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Marginal curtailment and the efficient cost of clean power

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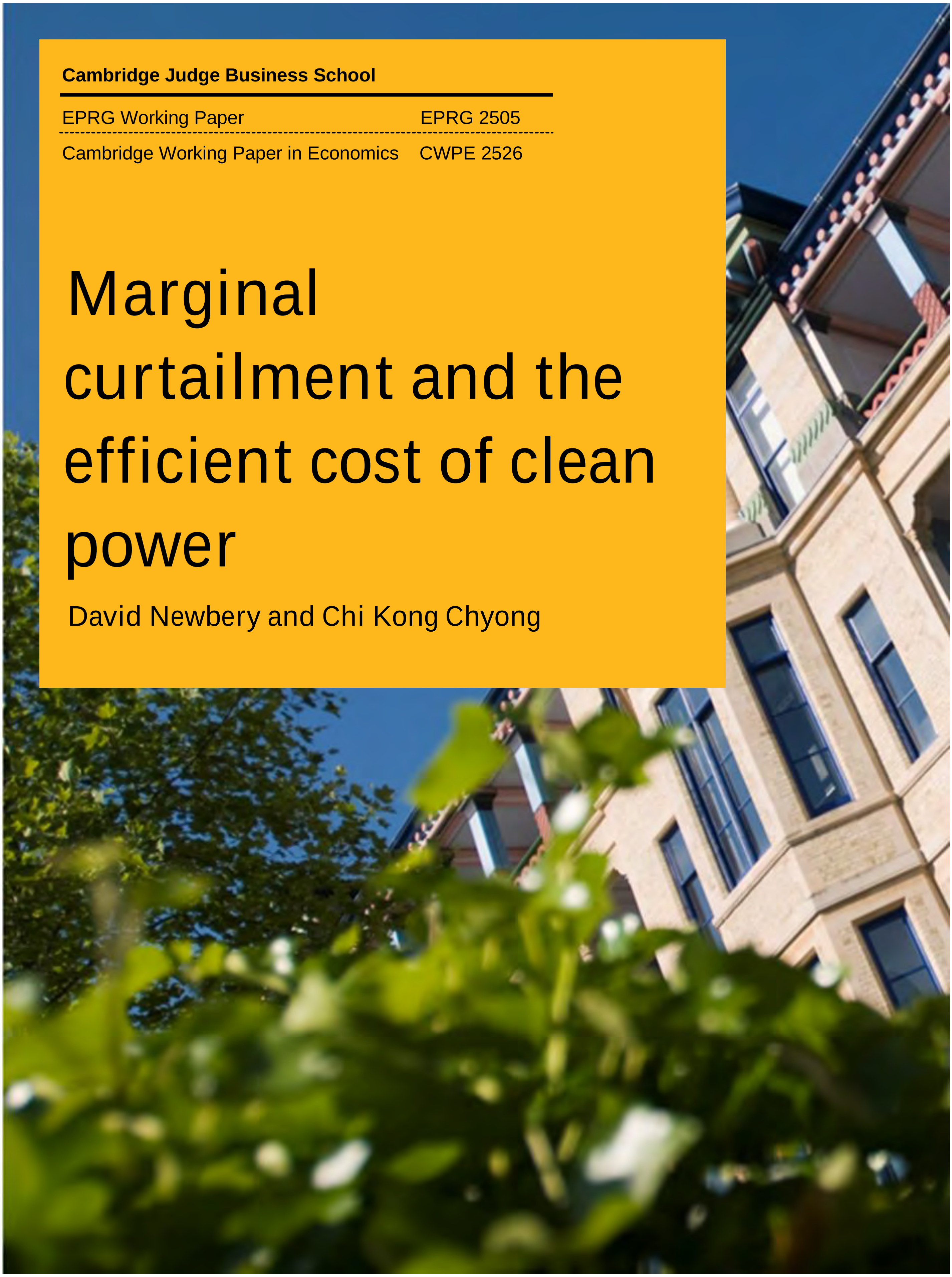

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Abstract : At high penetration levels, the marginal curtailment of an extra MW of wind is typically 3+ times its average. With a portfolio of different technologies (on- and offshore wind, solar PV), an extra MW of any single technology can increase the curtailment of all technologies, increasing the marginal: average curtailment ratio and the cost of displacing fossil generation. Higher expected future capacity factors amplify this ratio. Increasing nuclear output can also cause renewable curtailment but its effect is smaller than increasing VRE to give equivalent extra output. The choice of the VRE expansion plan depends on whether the potential, average, or marginal capacity factors are used. Storage and trade significantly increase the curtailment ratio but lower delivered costs, with higher VRE penetration in neighbouring markets further amplifying curtailment.

Keywords : Variable Renewable Electricity, Marginal Curtailment, Least-cost Expansion.

JEL Classification : H23; L94; Q28; Q42; Q48

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Marginal curtailment and the efficient cost of clean power[1]

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Abstract

As variable renewable electricity (VRE, wind and PV) penetration increases, the additional electricity delivered by one more unit of VRE capacity is substantially smaller than either its nominal output or average production: capacity of one VRE technology increases curtailment of other VRE technologies, magnifying its impact. Consequently, investment and policy decisions should be based on marginal rather than average delivered output, implying substantially higher marginal levelised costs than conventional LCoE calculations suggest. Their magnitude is calculated for a possible 2030 British scenario in which all internal congestion has been eliminated. The potential benefit of additional exports and storage depend on the extent of Continental VRE expansion. Additional nuclear power displaces some VRE, reducing its carbon benefit but by less than expanding VRE.

Keywords: variable renewable electricity, marginal curtailment, LCoE, support design,

JEL: H23; L94; Q42; Q48

1. Introduction

As variable renewable electricity (VRE: wind and solar PV) comes to dominate, electricity systems increasingly face periods in which potential VRE output cannot be fully absorbed. The surplus must be curtailed (i.e. spilled or wasted). Curtailment is now routine: in 2024, British (mainly Scottish) wind farms had about 13% of their potential output curtailed — 10.5 TWh out of 80.7 TWh of potential wind generation, against 264 TWh of consumption. Under most support arrangements, curtailed output is compensated at the support price, so failure to deliver (curtailment) imposes material costs on final consumers. A simple way to see the cost implication is that, if, as in Scotland, some wind farms were curtailed by more than half, that would double the cost of delivered electricity. Curtailment is not a peculiarly British problem and arises for a variety of reasons, including mid-day oversupply in PV-rich systems (Halttunen et al., 2020; O'Shaughnessy et al., 2020), transmission congestion (Bird et al., 2015), and system-wide operational constraints to maintain stability (Mehigan et al., 2020).

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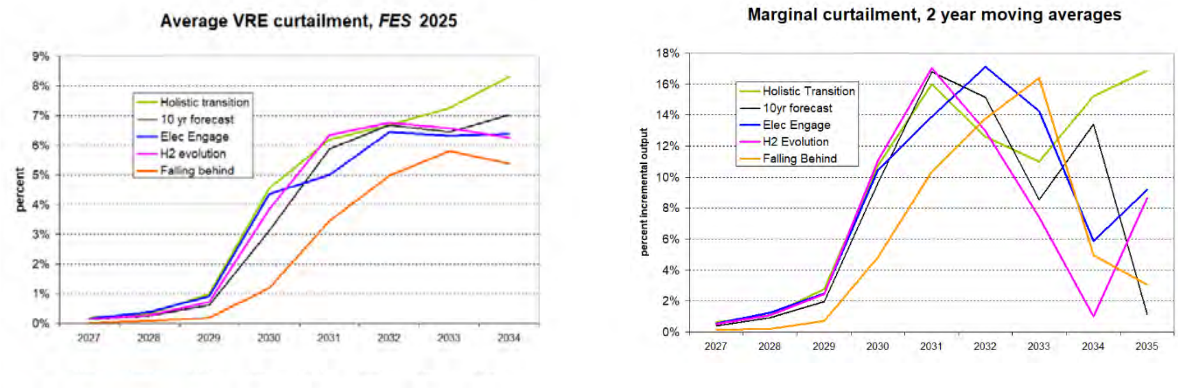
This raises a question that conventional cost comparisons sidestep. When an investor adds one more megawatt of renewable capacity, how much electricity does it actually deliver, and what does that delivered output cost? The usual answer – the levelised cost of electricity (LCoE) – assumes that all potential output is sold. Once curtailment is material, that assumption fails, and it fails differently for the average plant and for the marginal one. If a fraction of output is spilled, the cost per unit of energy actually delivered is scaled up by $1/(1 - c_a)$, where c_a is the share of output curtailed. At Great Britain (GB)'s 2024 13% average wind curtailment, delivered cost is already about 15% above the nominal LCoE – and above the price paid under GB's auctioned Contracts for Difference (CfDs).

Our central message is that even average curtailment understates the cost of expansion. Unless the transmission network is reinforced in step with new VRE, the cost-relevant quantity for an investment decision is not the average curtailment of the existing fleet but the *marginal* curtailment, c_m: the share of potential output of the last unit of capacity spilled. The long-run marginal cost of VRE then scales roughly as $1/(1 - c_m)$. Because curtailment occurs only when the system is already in surplus, the last unit added is exposed to those surplus hours far more than the average unit. For onshore wind in the Single Electricity Market (SEM) of Ireland, Newbery (2021) found that the marginal-to-average curtailment ratio, c_m/c_a, was typically above 3. The wedge between c_m and c_a is why curtailment accelerates as penetration rises when network expansion lags.

This article goes further to show that with more than one VRE technology, installing an extra MW of one technology one does not only curtail itself: by deepening the surplus in the hours it produces, it also forces the others off the system. These interactions are illustrated in Figure 3 below for a possible GB 2030 VRE portfolio. Interactions between different technologies were noted by López Prol and Zilberman (2023). They found that Californian solar penetration increased both solar and wind curtailment, and wind penetration increased solar curtailment. Novan & Wang (2024, p6) estimate that "an additional MWh of wind generation during the midday hours reduces utility-scale solar supply by 0.1 MWh. Similarly, a 1 MWh increase in small-scale solar only increases curtailment at utility-scale renewables by 0.033 MWh." The same logic extends to inflexible low-carbon plants: because spilling wind or solar is cheaper than turning down nuclear, additional nuclear running in surplus hours curtails VRE and so delivers less net-zero-carbon energy than its own output suggests. Such interactions have largely been overlooked or buried within the complexity of scenario models (e.g., NESO, 2024).

Figure 1 demonstrates why the distinction between average and marginal curtailment matters. NESO (2025) provides average curtailment year by year (Figure 1a), but does not provide marginal curtailment. The data allow this to be roughly estimated (while the underlying model would have allowed an accurate measure), as shown in Figure 1b.

Figure 1 a: Projected average and b: marginal curtailment rates, 2 yr. moving averages



Source: NESO (2025)

Notes: Note that the marginal curtailment axis is twice that of the average graph. Generation data excludes generation required to offset network constraints that would impact curtailment. *Holistic Transition* represents the fastest transition path (higher electrification rates), Electric Engagement less so, *Hydrogen Evolution* has lower electrification for heat and more fossil generation, while *Falling Behind* (Counterfactual in FES24) is what it says.

The implication is that the long-run marginal cost of delivered renewable electricity can lie well above its LCoE, and that the gap varies across technologies in ways the LCoE cannot reveal. That matters for least-cost planning and, directly, for auction design: a technology-neutral auction that ranks bids on nominal £/MWh need not select the cheapest addition once marginal curtailment and its spillovers are counted.

We quantify these effects with a unit commitment and economic dispatch (UCED) model calibrated to a plausible GB 2030 generation portfolio (NESO, 2024). We add a small increment of one technology at a time, re-solve the system, and read off the extra curtailment – for that technology and for the others. We then vary the system's flexibility: interconnection to neighbouring markets, storage, the level of European VRE, nuclear availability, and the controllability of distributed VRE. Throughout, we treat GB as a single "copper plate" with no internal transmission limits. This is deliberate: it isolates the curtailment that survives even when the internal grid has caught up with VRE – the curtailment driven by GB-wide surplus and by the need to keep enough synchronous plant running for stability – from the congestion-driven curtailment that dominates GB today, where the binding problem is the limited transfer capability from Scotland to England. A companion paper (Chyong and Newbery, 2026) adds those internal constraints and shows that they further magnify curtailment.

The article makes three contributions. First, we show that increasing investment in one VRE technology increases curtailment in all VRE technologies. That was theoretically demonstrated by Newbery (2025b) and is here quantified in a possible 2030 GB energy scenario. These spillovers magnify total marginal curtailment and reduce the net decarbonisation delivered by incremental capacity – an effect that extends to nuclear. Second, it derives long-run marginal costs for each VRE technology and shows that these LRMCs can diverge sharply from conventional LCoE rankings. Third, it quantifies how far additional uses of surplus VRE, such as exporting over expanded interconnectors and storage, reduce curtailment.

The remainder of the article is structured as follows. Section 2 reviews the literature on VRE integration, market value, and curtailment where directly relevant to the topics of this article. Section 3 sets out the definitions and methods used to compute average and marginal curtailment, as well as the implied long-run marginal cost measures. Section 4 presents results for the baseline configuration and for expanded trade and storage. Section 5 discusses implications for procurement and support design. Section 6 concludes.

2. The economics of marginal curtailment

2.1 Why the last megawatt is curtailed more than the average

Curtailment occurs only during hours when potential VRE output exceeds the system's capacity to absorb it. In every other hour, an extra MWh is sold in full. So the average MW curtails only in surplus hours, whereas the last MW added is, by construction, most exposed to those hours. This would be sharply revealed if the last entrant were the first to be curtailed and would bear the brunt of the required total curtailment. Average and marginal curtailment therefore differ – and they differ significantly.

A simple picture makes the mechanism concrete. Order the hours of the year by the size of the VRE surplus. As installed capacity V rises above the level V_0 at which surpluses first appear, the curtailed energy is roughly the area of a triangle whose height is the excess capacity ($V - V_0$) and whose width is the fraction of the year in surplus. Average curtailment is that area spread over all output; the triangle grows with the square of ($V - V_0$) but is divided by the larger base V. Adding one more MW raises the height of the triangle across its whole width, so the extra curtailment – the marginal rate – tracks the triangle's edge, not its average. The last unit is spilled far more than the typical unit.

Newbery and Biggar (2024) make this exact for a piecewise-linear surplus schedule in which new capacity is added in proportion to the existing fleet.[4] The marginal-to-average ratio is then

$$c_m/c_a = (V + V_0)/(V - V_0), \tag{1}$$

with V_0 the capacity at which curtailment begins.[5] Two comparative statics follow, and both appear in our results. Raising penetration (larger V, V_0 fixed) lowers the ratio; lowering average curtailment by deferring its onset (larger V_0) raises it. The ratio is large precisely when average curtailment is small relative to capacity – the situation a well-interconnected, high-VRE system is heading towards. NESO's own projections in Figure 1 above showed the difference between average and marginal curtailment.

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[4] Figure 3 is approximately piecewise linear.

[5]The geometric demonstration is simple. Curtailment is the area of the triangle of height $V - V_0$ and length y^* (the fraction of the year VRE is curtailed). Average curtailment is then ½($V-V_0$)·y^*/V. Adding 1 MW of capacity increases the curtailment triangle by raising the base roughly y^* MW, so $c_m/c_a \approx 2V/(V-V_0)$. A more accurate estimate lets potential output increase in proportion to existing potential output, so the curtailment increase is a trapezium (added to the hypotenuse of the curtailment triangle) of area ½(1+V_0/V)·y^* rather than y^*. The geometry is laid out in Newbery and Biggar (2025).

2.2 How one technology curtails all

When a surplus occurs, every VRE generating in that hour is curtailed. The effect of adding capacity is not confined to that technology. Suppose offshore wind expands. In the windy hours when offshore output is high, onshore wind – strongly correlated with it – is high too, and the deeper surplus spills some of that onshore output as well; any solar generating in those hours is likewise curtailed. The increase in one technology thus curtails the others. We call these cross-technology spillovers, and they are central to our results.

Spillovers depend on how each technology's output aligns with system-wide surpluses, which is why they differ across technologies. Wind and solar are negatively correlated in GB (Appendix B), so wind expansion spills relatively little solar, while solar expansion – concentrated in the same midday hours across a wide area – can spill a good deal of other solar. The upshot is that total marginal curtailment exceeds own-technology curtailment alone, and that the size of the spillover is a property of the portfolio, not of any technology in isolation. López Prol and Zilberman (2023) document the empirical counterpart in California; Newbery (2025b) provides the theory; Section 4 quantifies both for GB 2030.

The same mechanism links VRE to inflexible low-carbon plant. Nuclear output provides valuable system stability, but in surplus hours it is costlier to curtail than wind or solar, so it is the renewables that are curtailed. Additional nuclear running in those hours, therefore, curtails VRE, and its net contribution to zero-carbon electricity is less than its own generation. We return to this in Section 4.4.2.

2.3 From curtailment to delivered cost

To turn curtailment into cost, we need only a few quantities, defined here. For technology j, average curtailment $c_{a,j}$ is its curtailed energy over the year divided by its potential energy; marginal curtailment $c_{m,j}$ is the extra curtailed energy caused by a small increment of j, divided by that increment's potential energy. Crucially, this extra curtailed energy is measured system-wide: it includes the additional curtailment the increment induces on the other technologies – the spillovers of §2.2 – so the cost-relevant marginal curtailment is this system-wide quantity. It is what enters MCF in equation (3). Both are read directly from the model in Section 4.

Curtailment lowers the energy a plant delivers relative to its potential. The potential capacity factor PCF is the output a plant would achieve if nothing were spilled. After curtailment, the fleet achieves an average capacity factor ACF, and the marginal plant a marginal capacity factor MCF:

$$\mathrm{ACF}_j = (1 - c_{a,j})\cdot\mathrm{PCF}_j, \qquad (2)$$

$$\mathrm{MCF}_j = (1 - c_{m,j})\cdot\mathrm{PCF}_j. \qquad (3)$$

(We write c_a and c_m, not *ac* and *mc*, to avoid confusion with average and marginal cost.)

Because the fixed costs of a wind or solar plant are spread over the energy it delivers, its delivered cost moves inversely with its capacity factor. The average delivered cost therefore scales with PCF/ACF = $1/(1 - c_a)$, and the marginal delivered cost with PCF/MCF = $1/(1 - c_m)$. The last term is the heart of the paper: a marginal curtailment of, say, 40% raises the long-run marginal cost of new capacity by about two-thirds ($1/0.6 \approx 1.67$), even though construction costs and the wind or sun are unchanged. Section 5 converts these capacity-factor ratios into corresponding levelised costs and applies them to GB cost data; the intervening sections provide the curtailment numbers.

3. Model and scenarios

3.1 The model

We use a unit commitment and economic dispatch (UCED) model of the GB market and 19 neighbouring markets – 22 price zones in all – that co-optimises generation and cross-border trade subject to interconnector limits (Chyong and Newbery, 2022; Newbery and Chyong, 2025). GB itself is represented as a single copper plate, with internal transmission limits switched off. As explained in Section 1, this isolates the surplus-driven and stability-driven curtailment that remains once the internal grid has caught up with VRE from the congestion-driven curtailment that dominates GB today (the subject of Chyong and Newbery, 2026). Appendices A and B gives the model and data in full.

The experiment is the same throughout. We scale up the hourly potential-output profile of one technology so that it adds, on average, 100 MWh/hr over the year (876 GWh/yr.), re-solve the system, and record the change in curtailment, technology by technology. The increment is small relative to installed capacity – increasing it tenfold changes marginal curtailment per MW by about 3% – and the technology-by-technology effects are very nearly additive (summing three separate increments differs from a combined increment by about 0.5%). The same 100 MWh/hr increment is used for every technology and scenario. Because the increment is defined in equal potential-energy terms – not equal capacity – the resulting marginal curtailment factors are directly comparable across technologies per unit of potential energy, which is the normalisation required for the cost comparison.

3.2 What forces curtailment, and what we exclude

Two things force curtailment in the model. The first is a system-wide stability limit: because wind and solar supply none of the rotational inertia that keeps alternating-current frequency steady, instantaneous VRE is capped at 90% of system demand[6] to keep enough synchronous plant running (the mechanism, and the exact curtailment rule, are in Appendix A). The second is GB-wide surplus, when potential VRE exceeds demand even after exports and storage. In the base case, the resulting curtailment is shared across technologies pro rata to offered output; Section 5.2 and Appendix C consider efficient, cost-order curtailment instead.

What the copper-plate assumption excludes is internal congestion. The distinction is not merely definitional. Ireland's SEM, which reports the two separately, dispatched down 14% of wind in 2024 – 9.3 percentage points from transmission constraints and 4.3 from system-wide constraints (EirGrid/SONI, 2025). Modelling GB as a copper plate keeps only the second, the curtailment that survives grid reinforcement; the congestion that dominates GB today is added in Chyong and Newbery (2026) and further magnifies marginal curtailment.

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[6]We are indebted to Tim Green for the plausibility of this 2030 GB target, significantly above the present limit.

If technologies were instead curtailed by avoidable cost – onshore wind first (which has the highest variable O&M), then offshore, with PV (no avoidable cost) rarely curtailed at all – the outcome would follow from exposing VRE to efficient balancing-market prices. The market is moving in that direction: Elexon is consulting on removing distortions from CfD and Renewables Obligation support so that curtailment aligns with the bid stack merit order. However, EC guidance that no payment is due once prices reach zero could leave all VRE treated alike. The consequences for technology rankings are taken up in Section 5.2.

3.3 Scenarios

The baseline pairs the 2030 VRE capacities from the *Future Energy Scenarios* (*FES*) *Hydrogen Evolution* (*HE*) pathway (NESO, 2024) with 2023 levels of interconnection and storage – a system in which renewables have outrun their complementary ability to absorb surplus VRE. Successive scenarios then add that ability and stress it (Table 1): planned 2030 interconnection alone; interconnection plus 2030 storage; higher European VRE (which competes for the same export windows); delayed nuclear (HPC Unit 2); and embedded VRE, where 30% of renewables sit on the distribution network, invisible to the system operator and so uncurtailable. Each scenario isolates one margin of spatial or temporal flexibility while holding GB VRE capacity fixed.

Table 1. Summary of Input Assumptions across Scenarios

Input Parameter	Baseline	Interconnectors Only	Interconnectors & Storage	High EU VRE	Low Nuclear	Embedded VRE
VRE Installed Capacity (2030)	As per FES HE 2030 projections	Same as baseline	Same as baseline	Same as baseline	Same as baseline	Lower (grid only)
Interconnector Capacity	2023 levels (8.5 GW)	2030 levels (14.5 GW)	2030 levels	2030 levels	2030 levels	2030 levels
Storage Capacity	2023 level (7.4 GW)	7.4 GW	26.6 GW	26.6 GW	26.6 GW	26.6 GW
Demand Side Response (DSR)	1.3 GW	1.3 GW	2 GW	2 GW	2 GW	2 GW
Curtailment Visibility (VRE types)	All VRE controllable	Same as baseline	Same as baseline	Same as baseline	Same as baseline	Grid-connected only (70% of 2030)
European VRE Assumptions	FES HE 2030 baseline	Same as baseline	Same as baseline	NECP 2023 (higher EU VRE)	Same as baseline	Same as baseline
Nuclear Capacity	4.6 GW (HPC Units 1 & 2)	Same as baseline	Same as baseline	Same as baseline	2.5 GW (Unit 2 delayed)	Same as baseline

Notes: All scenarios use identical VRE increment modelling (average 100 MWh/hr. 876 GWh/yr.) to calculate marginal curtailment; curtailment treatment changes only in the Embedded VRE case, where 30% of VRE is uncurtailable; High EU VRE scenario increases VRE availability across interconnected EU countries in line with their National Energy and Climate Plans (NCEP), limiting GB's export potential; Low Nuclear scenario reflects commissioning delays at Hinkley Point C, reducing must-run nuclear output and altering VRE-nuclear interactions; Interconnectors & Storage case reflects full 2030 planned investment and serves as the most technologically enabled configuration.

At baseline, 93% of annual National Demand (ND) is met by non-fossil sources (98% if biomass is included). Exports amount to 11.1% of ND, with net exports at 1.9%. Demand-side response (DSR) contributes an average of only 53 MW during curtailed hours, thereby playing a negligible role in mitigating VRE surpluses. The remaining scenarios are described as they arise in Section 4.

The three technologies' output profiles differ sharply – PV is strongly diurnal, and the two wind technologies differ in persistence and season – and it is these differences that drive the spillovers of Section 2.2. Figure 2 shows them as quarterly averages of hourly potential output. Appendix B provides a fuller description of the statistical properties of GB VRE and a breakdown between onshore and offshore wind.

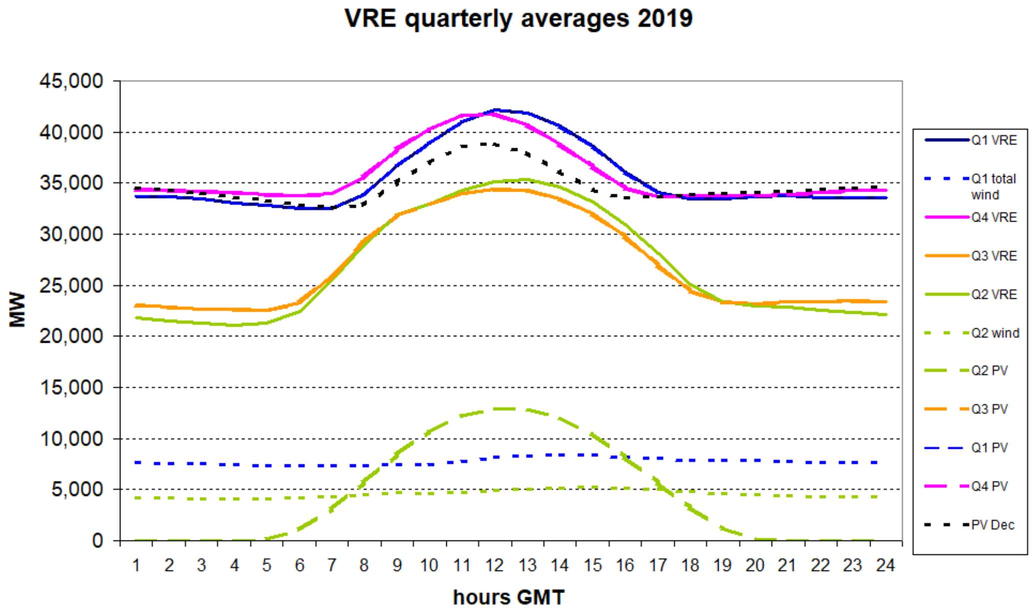

Figure 2 Quarterly averages of potential output per hour by technology and total VRE

Source: UCED outputs: Appendix A and B. Wind is combined on- and off-shore wind

4. Results

4.1 Baseline: 2030 renewables on a 2023 grid

Table 2 reports the baseline, in which 2030 VRE faces 2023 interconnection and storage. Panel A is the starting point: installed capacity, potential output, and the average curtailment c_a each technology would suffer. Offshore wind, for example, has 198,854 GWh of potential output and 14,902 GWh curtailed, an average rate of 7.5%.

Panels B–D run the increment experiment of Section 3. Each scales one technology's profile up by 100 MWh/hr (876 GWh/yr.) and re-solves; the rise in curtailment is then split into (i) the technology's own curtailment, (ii) the spillover onto each other technology, and (iii) the system-wide total (the "Total VRE" column).

Table 2. Pro-rated curtailment results for the baseline scenario (2023 storage and export capacity)

Metric	Total VRE	OFF	ON	PV	Curtailed hours
Panel A. Baseline system and average curtailment					
Baseline capacity (GW)	94.20	43.48	23.08	27.64	
Potential output (GWh/yr)	282,073	198,854	56,935	26,284	
Fleet PCF	34.2%	52.2%	28.2%	10.9%	
Potential capacity factor of new increment, PCF		60.0%	34.0%	11.0%	
Baseline curtailment (GWh)	21,338	14,902	5,021	1,415	2,548
Average curtailment, c_a	7.6%	7.5%	8.8%	5.4%	
Panel B. Increment in offshore wind (OFF)					
Capacity increment (MW)	166.7	166.7	0	0	
Potential increment (GWh/yr)	876	876	0	0	
Curtailment after increment (GWh)	21,720	15,178	5,109	1,433	2,584
Increase in curtailment (Δ), GWh	381	275	88	18	36
Marginal curtailment (% of increment)	43.5%	31.4%	10.1%	2.0%	
System-wide c_m/c_a ratio		5.81			
PCF/MCF = $1/(1 - c_{m,sys})$		1.77			
Panel C. Increment in onshore wind (ON)					
Capacity increment (MW)	294.1	0	294.1	0	
Potential increment (GWh/yr)	876	0	876	0	
Curtailment after increment (GWh)	21,805	15,231	5,132	1,442	2,588
Increase in curtailment (Δ), GWh	466	329	111	27	40
Marginal curtailment (% of increment)	53.2%	37.5%	12.7%	3.0%	
System-wide c_m/c_a ratio			6.04		
PCF/MCF = $1/(1 - c_{m,sys})$			2.14		
Panel D. Increment in solar PV (PV)					
Capacity increment (MW)	909.1	0	0	909.1	
Potential increment (GWh/yr)	876	0	0	876	
Curtailment after increment (GWh)	21,577	15,046	5,070	1,461	2,577
Increase in curtailment (Δ), GWh	239	144	49	46	29
Marginal curtailment (% of increment)	27.3%	16.5%	5.6%	5.3%	
System-wide c_m/c_a ratio				5.07	
PCF/MCF = $1/(1 - c_{m,sys})$				1.38	

Notes: c_a is average curtailment (curtailed output as a percentage of potential output). In each increment panel, one technology's hourly potential-output profile is proportionally scaled to add an average of 100 MWh/hr over the year (876 GWh/yr). The row "Marginal curtailment (% of increment)" reports the increase in curtailment as a percentage of the potential increment, decomposed by curtailed technology; the Total VRE entry is the system-wide marginal curtailment (the row sum). PCF and MCF denote potential and marginal capacity factors, with MCF = PCF$(1 - c_{m,sys})$ and PCF/MCF = $1/(1 - c_{m,sys})$. Assumed capacity factors are explained in Appendix C.

Offshore wind illustrates the decomposition. The 876 GWh/yr increment raises total curtailment by 381 GWh, a system-wide marginal curtailment of 43.5%. Of that, 31.4 points are offshore wind's own curtailment and 10.1 and 2.0 points are spillovers onto onshore wind and PV. Against an average rate of 7.5%, the marginal-to-average ratio is 5.8. The implied cost mark-up is PCF/MCF = $1/(1 - 0.435) = 1.77$: the long-run marginal cost of offshore wind is about 77% above its nominal LCoE, before any variable O&M. The onshore and PV increments tell the same story, with ratios of 6.0 and 5.1. The final column counts the curtailed hours – the periods in which the marginal value of VRE is near zero and GB-wide prices should fall to zero or below.

Two features stand out. First, average curtailment is low (7–9%) despite the large VRE build, because the copper-plate assumption removes internal congestion and leaves only the stability limit and GB-wide surplus to bind; the companion paper with internal constraints finds materially higher curtailment (Chyong and Newbery, 2026). A low c_a with a high c_m necessarily produces a high c_m/c_a. Second, the ratios here exceed the single-technology SEM estimates for two reasons. New turbines are assumed more productive than the ageing fleet – PCF 60% against the realised 2019 fleet load factor of 51.6% for offshore wind (a factor of 1.16), and 34% against 27% for onshore (1.26), benchmarked against the actual fleet in Table C.2 rather than the modelled 2030 fleet PCF of Table 2 – which, with V_0 raised, lifts c_m/c_a as Section 2.1 predicts. More importantly, the portfolio spillovers add the cross-technology terms that a single-technology calculation misses.

The marginal effects are robust (Section 3.1), but cross-technology comparisons need care, because they depend on the curtailment-ordering rule. Appendix C, Table C.2 repeats the exercise under efficient curtailment – onshore wind first, then offshore, PV last (and, in the base case, never). Total curtailment is unchanged, but its distribution across technologies, and hence the technology-specific ratios, change markedly; under that rule, PV is not curtailed at all in the base case, so a c_m/c_a for PV is not meaningful.

4.2 The impact of interconnector expansion on curtailment

GB's interconnector capacity is set to rise by about 70% by 2030, from 8.5 to 14.5 GW. Holding storage at 2023 levels, Table 3 raises interconnection to its 2030 level to isolate the value of trade alone.

Table 3. Curtailment rates and ratios, with planned interconnectors but no extra storage

Metric	Total VRE	OFF	ON	PV	Curtailed hours
Baseline curtailment with 2023 interconnectors (GWh)	21,338	14,902	5,021	1,415	2,549
Curtailment with 2030 interconnectors (GWh)	11,616	8,039	2,748	828	1,603
Reduction from interconnector expansion (GWh)	9,722	6,863	2,273	587	946
PCF/ACF = $1/(1 - c_a)$		1.04	1.05	1.03	
Curtailed hours/year (increment case)		1,615	1,615	1,602	
System-wide c_m/c_a ratio		5.97	7.40	4.92	
PCF/MCF = $1/(1 - c_{m,sys})$		1.32	1.56	1.18	

Notes: Baseline curtailment with 2023 interconnectors is repeated from Table 2 for comparison. Definitions and calculations as in Table 2. Full increment decompositions are reported in Appendix C, Table C.1

Trade is powerful in moderating curtailment. Baseline curtailment falls from 21,338 to 11,616 GWh – 9,722 GWh, or 46% – with the largest absolute fall for offshore wind and reductions for all three technologies; curtailed hours fall too, so periods of curtailment shorten as well as shrink. Average curtailment drops accordingly: PCF/ACF moves towards 1 for each technology, so delivered output approaches potential output. Marginal curtailment also falls, lowering PCF/MCF and, counterintuitively, even where cm/ca rises, the long-run marginal cost of new capacity – a result proved in Newbery (2025b). The cost ranking is unchanged (ON > OFF > PV). But the ratios stay high: trade eases the non-linearity of curtailment without removing it, and its value depends on neighbours having spare demand when GB is in surplus – the subject of Section 4.4.1.

4.3 The impact of additional storage on curtailment

Adding 2030 storage on top of 2030 interconnection isolates temporal flexibility. Storage rises from 7.4 to 21.7 GW and DSR from 1.3 to 2 GW.

Table 4. Curtailment rates and ratios, with planned interconnectors, storage and DSR

Metric	Total VRE	OFF	ON	PV	Curtailed hours
Curtailment with 2030 ICs only (GWh)	11,616	8,039	2,748	828	1,603
Curtailment with 2030 ICs + storage (GWh)	8,771	6,075	2,088	608	1,341
Reduction from storage + DSR (GWh)	2,845	1,964	660	220	262
PCF/ACF = $1/(1 - c_a)$		1.03	1.03	1.03	
System-wide marginal curtailment, $c_{m,sys}$		19.8%	27.9%	12.3%	
System-wide c_m/c_a ratio		7.44	9.18	5.41	
PCF/MCF = $1/(1 - c_{m,sys})$		1.25	1.39	1.14	

Notes: Top line is repeated from Table 3 for comparison. Definitions and calculations as in Table 2.

Curtailment falls further, from 11,616 to 8,771 GWh — another 2,845 GWh, or 24% – across all three technologies, with curtailed hours down from 1,603 to 1,341. Storage complements interconnection: one shifts surplus across space, the other across time. PCF/ACF moves closer still to one, and PCF/MCF falls again, lowering long-run marginal cost for every technology. Figure 3 shows the resulting curtailment curves, ranked by total curtailment; the way the technologies stack and interact is the visual counterpart of the spillovers in Section 2.2.

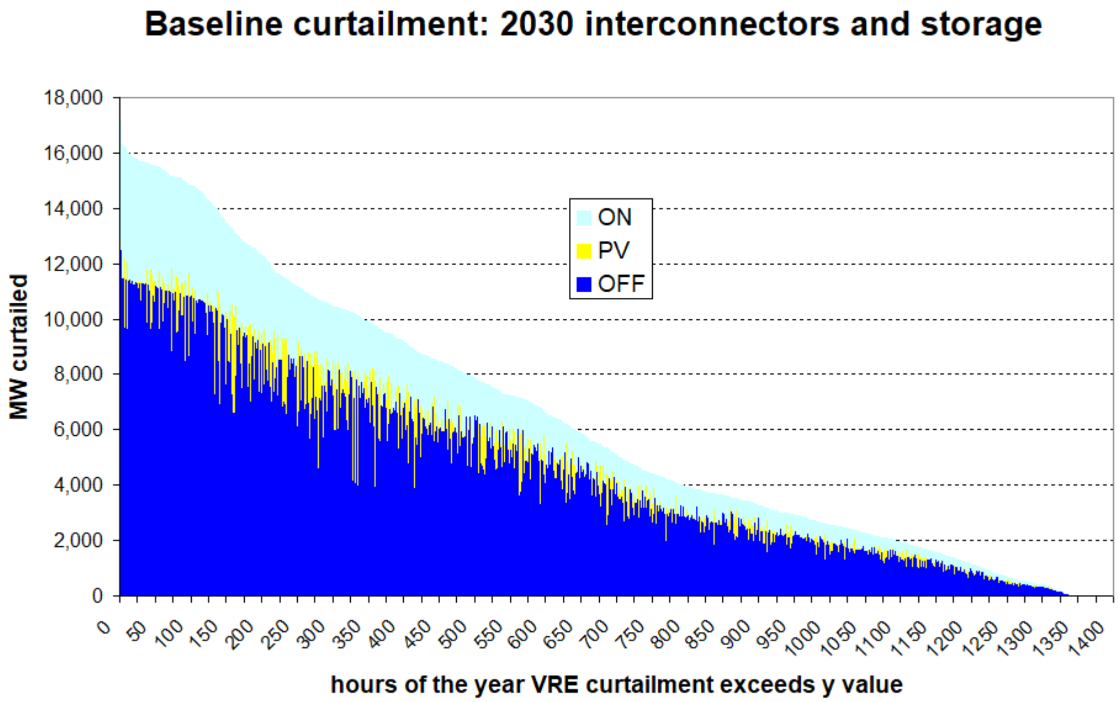

Figure 3 Curtailment curves for 2030 with planned interconnectors and storage ranked by total curtailment

Notes: Technologies ranked by total, pro-rata curtailment, 2030 storage & interconnector capacity. OFF is Offshore wind, ON is onshore wind and PV is Solar PV.
Source: as for Table 4.

The curtailment savings, however, are only a small part of what storage is worth. The extra 14.3 GW of storage and 0.7 GW of DSR (about 15 GW of flexibility) cut curtailment by 2,845 GWh and curtailed hours by 262. A four-hour battery fleet discharging for four hours a day would shift roughly 21,900 GWh/yr — nearly eight times the curtailment it would relieve. Valued against CCGT at a carbon-inclusive £145/MWh, the 2,845 GWh saving is worth about £411 million a year, or some £28/kW-yr across the 15 GW. Against the NREL (2023) mid-estimate of roughly £950/kW for a 2030 four-hour battery (2022 prices), curtailment relief alone covers only a small share of annualised capital cost: storage must earn most of its return from arbitrage, reserve and ancillary services, not from reducing curtailment.

4.4 Sensitivities: higher EU VRE, lower nuclear output, embedded VRE

Table 5 examines the implications for curtailment and cost of higher EU VRE, lower nuclear output and the consequences of an inability to curtail embedded (typically household and distribution-connected) VRE

Table 5. Capacities, outputs and curtailment under sensitivity cases

Metric	Nuclear	Total VRE	OFF	ON	PV	Curtailed hours
Panel A. Reference case: 2030 interconnectors + storage (FES EU VRE)						
Capacity (GW)	4.6	94.2	43.48	23.08	27.64	
Curtailment (GWh)		8,771	6,075	2,088	608	1,341
Output (GWh/yr)	31,536	273,301				
PCF/ACF = $1/(1 - c_a)$			1.03	1.03	1.03	
System-wide c_m/c_a ratio			7.44	9.18	5.41	
PCF/MCF = $1/(1 - c_{m,sys})$			1.25	1.39	1.14	
Panel B. High EU VRE (NECP-based European VRE expansion)						
Output (GWh/yr)	31,536	267,346				
Curtailment (GWh)		14,727	10,079	3,382	1,266	1,859
PCF/ACF = $1/(1 - c_a)$			1.05	1.05	1.05	
System-wide c_m/c_a ratio			6.1	8.2	4.0	
PCF/MCF = $1/(1 - c_{m,sys})$			1.37	1.68	1.24	
Panel C. Lower nuclear output (HPC delayed)						
Nuclear capacity (GW)	2.5	94.2	43.5	23.1	27.6	
Curtailment (GWh)		7,369	5,123	1,748	498	1,141
Output (GWh/yr)	20,012	274,704				
Change relative to reference (GWh/yr)	-11,524.2	-1,402.7	-951.9	-340.6	-110.2	-200
VRE curtailment per MWh of nuclear output change		12.2%				
Panel D. Embedded VRE (partial non-curtailability of embedded resources)						
Grid-connected capacity (GW)	4.6	65.9	30.4	16.2	19.4	
Grid output (GWh/yr)	31,536	197,451	139,197	39,854	18,399	
Embedded VRE output (GWh/yr)		84,622	59,656	17,080	7,885	
Grid-curtailed VRE (GWh)		7,085	4,909	1,681	495	1,234
PCF/ACF = $1/(1 - c_a)$			1.03	1.04	1.03	
System-wide c_m/c_a ratio			13.6	9.6	7.3	
PCF/MCF = $1/(1 - c_{m,sys})$			1.41	1.31	1.16	

Notes: Panel A repeats 2030 interconnectors + storage from Table 4. Definitions and calculations as in Table 2. In Panel C the “Change relative to reference” row is not homogeneous across columns: the Nuclear figure is the change in nuclear output (the reduction from delaying HPC Unit 2), the Total VRE, OFF, ON and PV figures are changes in curtailment (a negative value is a fall in curtailment, and hence a rise in delivered VRE), and the final figure is the change in curtailed hours.

4.4.1 Higher EU VRE output

Interconnection only relieves curtailment if neighbours can absorb the surplus. Replacing the FES view of European VRE with the more ambitious *National Energy and Climate Plans* (*NECP*) – Figure 4 – and holding GB unchanged, total GB curtailment rises from 8,771 to 14,727 GWh (+68%), with curtailed hours up from 1,341 to 1,859. All technologies are affected, PV most, reflecting the coincidence of midday solar across interconnected systems. Marginal curtailment rises but by less than average: PCF/MCF goes from 1.25 to 1.37 (offshore), 1.39 to 1.68 (onshore) and 1.14 to 1.24 (PV). Onshore costs rise most, as most European wind is onshore. The lesson is that the case for more interconnection to Europe is not automatic: when European VRE is high and correlated with GB's, export windows narrow, and domestic flexibility – storage above all – matters more.

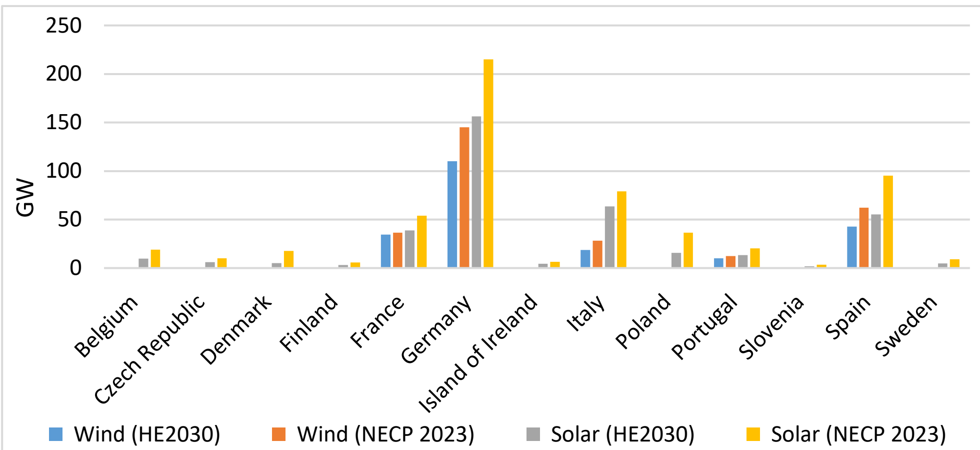

Figure 4 Projected wind and solar capacities for selected European countries under the *FES HE2030* baseline scenario and the *NECP 2023* high EU VRE scenario

Sources: (NESO 2024); NECP 2023 from: https://ember-energy.org/data/live-eu-necp-tracker

4.4.2. Lower nuclear output

In the reference case, nuclear supplies low-carbon, synchronous output, but in surplus hours it is costlier to turn down than VRE, so it adds to curtailment (Section 2.2). Cutting 2030 nuclear from 4.6 to 2.5 GW (HPC Unit 2 delayed) with everything else held constant, lowers total VRE curtailment from 8,771 to 7,369 GWh and curtailed hours from 1,341 to 1,141. The trade-off in delivered zero-carbon energy is the focus. Nuclear output falls by 11,524 GWh/yr, but because VRE curtailment falls, VRE delivery rises, so total zero-carbon output falls by only 10,121 GWh/yr. Put the other way, had Unit 2 run, its 11,524 GWh would have added only 10,121 GWh of net zero-carbon energy – about 88% of its output – the rest displaced as extra VRE curtailment. The relevant figure for appraising nuclear at high VRE penetration is this net contribution, not gross output. Flexibility in low-carbon plants, as discussed by Cany et al. (2018) and Mezősi et al. (2020), directly affects this margin.

4.4.3 Embedded VRE

Not all VRE is visible to or controllable by the operator – a gap GB's system operator has flagged as urgent[7] – because much onshore wind and most PV connect at distribution level. If this embedded output cannot be curtailed, it acts as a reduction in demand rather than as dispatchable supply, and the adjustment falls on the grid-connected fleet. Treating a uniform 30% of each technology as embedded and uncurtailable, grid-curtailed VRE is 7,085 GWh over 1,234 hours, and curtailment concentrates on the shrinking curtailable base. The resulting PCF/MCF markups are 1.41 (offshore), 1.31 (onshore), and 1.16 (PV)—above their baseline values for offshore wind and PV, while for onshore wind the markup is slightly below baseline, even though its c_m/c_a ratio rises. Making the embedded share uncurtailable lifts the ratio of marginal to average curtailment for all three technologies, as a smaller grid-connected base absorbs the same system adjustment.

This has both an operational and an economic reading. While embedded VRE is a must-take, the measured marginal curtailment for grid-connected technologies overstates the burden those technologies impose on their own, since part of it stems from uncurtailable embedded output. The remedy is not to discount the curtailment result but to improve the visibility, controllability and local flexibility of distributed resources, so that the adjustment need not fall so heavily on transmission-connected VRE.

5. Cost and policy implications

5.1 Which cost measure for which decision

Section 2.3 expressed delivered cost ratios as capacity factors; here, we translate them into money. Table 6 gives the cost assumptions – BEIS (2020) capital and O&M, uprated to 2023 prices – and the resulting LCoE at potential output: £62.48/MWh for offshore wind, £63.63 onshore, £53.67 for grid-scale PV (£79.53 mid-scale).

Table 6. Input cost assumptions for LCoE, LACoE and LMCoE calculations (£2023)

Cost input / parameter	OFF	ON	PV (grid-scale)	PV (mid-scale)
Potential capacity factor, PCF	60%	34%	11%	11%
Lifetime (years)	30	25	35	30
Degradation (%/yr)	1.0%	0.8%	0.5%	0.5%
Annualised fixed cost, F_j (5% real; £/kWyr)	£268.32	£152.64	£47.55	£71.33
Fixed-cost component at PCF (£/MWh)	£58.84	£56.34	£53.67	£79.53
Variable O&M, v_j (£/MWh)	£3.64	£7.29	£0.00	£0.00
LCoE at PCF (£/MWh)	**£62.48**	**£63.63**	**£53.67**	**£79.53**

Source: BEIS (2020) cost assumptions, uprated from 2018 to 2023 prices using CPI. Note: Mid-scale PV is 10–50 kW.

[7] https://www.neso.energy/about/innovation/our-innovation-projects/der-visibility-and-probabilistic-modelling

The LCoE assumes every potential megawatt-hour is delivered. With curtailment it must be adjusted, and which adjustment depends on the question. Annualising the fixed cost F_j over delivered rather than potential output gives the levelised average and marginal costs of delivered VRE:

$$\mathrm{LCoE} = F_j /(8760 \cdot \mathrm{PCF}_j) + v_j,$$

$$\mathrm{LACoE} = F_j /(8760 \cdot \mathrm{ACF}_j) + v_j, \tag{4}$$

$$\mathrm{LMCoE} = F_j /(8760 \cdot \mathrm{MCF}_j) + v_j, \tag{5}$$

where v_j is variable O&M (near zero except for wind). Setting $v_j = 0$,

$$\mathrm{LACoE/LCoE} = \mathrm{PCF}_j/\mathrm{ACF}_j = 1/(1 - c_{a,j}), \tag{6}$$

$$\mathrm{LMCoE/LCoE} = \mathrm{PCF}_j/\mathrm{MCF}_j = 1/(1 - c_{m,j}). \tag{7}$$

LACoE is the right measure for the existing fleet under proportional curtailment, and LMCoE for an incremental investment made while the network is held fixed (Engineering “system-LCoE” studies instead add integration costs – balancing, reserves, networks, backup – to the LCoE (Ueckerdt et al., 2013; Zerrahn and Schill, 2017); marginal curtailment is a distinct, and here often dominant, term.) These levelised costs should be read with care: in every case they assume an unchanged future pattern of curtailment, whereas investment in interconnection and storage is meant to reduce it. They are best treated as indicators of which technologies to prioritise and which to delay until that complementary investment arrives.

Table 7 applies equations (4)– (7) across the scenarios.

Table 7. Levelised cost estimates for VRE in 2030 (£2023)

2023 ICs & Storage, 2030 VRE	OFF	ON	PV	PV-mid
LCoE £/MWh	£62.48	£63.63	£53.67	£79.53
LACoE £/MWh, pro-rata curtailment	£66.57	£68.10	£56.77	£84.12
LMCoE £/MWh, pro-rata curtailment	£80.72	£94.05	£63.33	£93.85
LACoE £/MWh, efficient curtailment	£63.07	£85.48	£53.67	£79.53
LMCoE £/MWh, efficient curtailment	£107.78	£127.77	£73.80	£109.35
2023 storage, 2030 ICs & 2030 VRE				
LACoE £/MWh, pro-rata curtailment	£64.61	£66.05	£55.17	£81.76
LMCoE £/MWh, pro-rata curtailment	£81.31	£95.18	£63.33	£93.85
2030 ICs, Storage & FES EU VRE				
LACoE £/MWh, pro-rata curtailment	£64.09	£65.34	£55.17	£81.76
LMCoE £/MWh, pro-rata curtailment	£77.19	£85.60	£61.72	£91.46
2030 ICs, Storage, high EU VRE				
LACoE £/MWh, pro-rata curtailment	£65.15	£66.60	£56.23	£83.32
LMCoE £/MWh, pro-rata curtailment	£84.25	£101.94	£66.55	£98.62
2030 ICs, Storage, embedded VRE				
LACoE £/MWh, pro-rata curtailment	£64.30	£65.69	£55.17	£81.76
LMCoE £/MWh, pro-rata curtailment	£86.60	£81.10	£62.26	£92.25

Source: Tables 2–6. PV is grid-scale; PV-mid is 10–50 kW scale.

By 2030, average curtailment is low once interconnection and storage are built, so LACoE exceeds LCoE only modestly (3–5%). Newbery and Biggar (2025) show that in a new Renewable Energy Zone whose users pay for the deep network reinforcement that leaves incumbents no worse off, free entry guided by LACoE would be efficient. As expected, marginal curtailment is considerably higher than average curtailment: in every scenario, LMCoE is materially above both LCoE and LACoE, and rises with the marginal curtailment rate.

The distinction has implications for market design. Until 2020, CfD auctions priced output in £/MWh and compensated curtailment, so bidders could base bids on the LCoE.[8] Since 2020, VRE earns nothing when the GB-wide price falls to zero – which is when the system-wide curtailment modelled here occurs – so a bidder facing average curtailment on the wholesale market should bid the LACoE, while one facing non-firm access, or entering a saturated system as the marginal unit, should bid the LMCoE (as with the unsubsidised merchant entry of Simshauser and Newbery, 2024). The gap between LCoE and LMCoE in Table 7 is large across all technologies and widens as marginal curtailment increases. A technology can look competitive on LCoE yet be considerably more expensive at the margin.

5.2 Technology rankings and auction design

Table 7 shows that the ranking of technologies depends on the measure used. Rankings based on LCoE — or even LACoE — can differ from those based on LMCoE, the measure relevant to incremental procurement in a high-curtailment system. A technology-neutral auction that compares only nominal £/MWh bids may therefore not pick the least-cost addition from the system's point of view: two bids at the same strike price can carry very different marginal curtailment, and hence different LMCoE, once spillovers are included – most sharply where technologies differ in output timing and in their correlation with system surpluses, as offshore wind, onshore wind and PV do. This spillover is an externality: under pro-rata access an entrant internalises only its own incremental curtailment, so the bid it can profitably make reflects a private LMCoE that omits the extra curtailment it imposes on incumbents – the socially relevant comparison uses the full system-wide LMCoE, including those spillovers. Diallo and Kitzing (2020) make the related point that technology-neutral auctions can select socially less valuable technologies when several compete for the same price-independent support. However, they base their argument on the Market or Value LCoE discussed below and ignore marginal curtailment central to our argument.

This also questions the claim that some recent auctions are "subsidy-free". A strike price near the forward wholesale price does not make a technology costless to the system, nor the least-cost marginal addition; the relevant comparison is the cost of delivered marginal zero-carbon output, not of potential output. If curtailment is allocated efficiently rather than pro rata, the rankings shift again. While PV plainly has zero avoidable cost, the ranking of avoidable costs between onshore and offshore wind is less clear: most sources report only £ or $/kWyr operating

[8] https://assets.publishing.service.gov.uk/media/5fbc72958fa8f559e887e4f8/cfd-proposed-amendments-scheme-2020-ar4-government-response.pdf

costs (e.g. IRENA, 2025), whereas BEIS (2020), used here, separates fixed (£/MW-yr) from variable (£/MWh) O&M and shows onshore wind with the higher variable cost.

5.3 The marginal value of flexibility, and the value of output

Interconnection and storage both lower curtailment but in different ways, and both lower LMCoE because both lower marginal curtailment. Their value, though, is conditional. Interconnection's curtailment relief is reduced when neighbouring systems are in surplus at the same time (Section 4.4.1): its capacity remains unchanged, but its use for relieving curtailment does not. Spatial spreading still helps – output correlations fall with distance, improving the match of surplus to demand (Halttunen et al., 2020; Olauson and Bergkvist, 2016) – but surplus hours are increasingly correlated across space as European VRE rises. Storage remains useful in that setting, yet, as Section 4.3 showed, curtailment relief is only a modest part of its value; most of its value comes from arbitrage, reserves, and ancillary services.

Costs are only half the comparison: output is worth different amounts at different times. Table 8 reports each technology's market value as its output-weighted system marginal cost (SMC) – the price it would earn in non-stress hours in a competitive market – and a value ratio relative to the time-weighted SMC, which is one for a baseload plant. Cannibalisation, where VRE depresses prices in the hours it saturates, shows up as a value ratio below one 1 (Hirth, 2012 and Diallo and Kitzing, 2020 formalise this as the value factor used above). The wind value ratios are fairly stable across scenarios; PV's is more sensitive, falling as the scarcity mark-up on flexible plant rises. The SMC is not a complete value measure — it omits ancillary-service revenue and the scarcity mark-ups that flexible plant needs to recover capital — but those matter little for VRE, so the SMC is informative for comparing VRE technologies. Panel B's LMCoE/SMC ratio combines the two sides: technologies with similar nominal costs can have very different cost-to-value ratios once curtailment and timing are factored in.

Table 8. Output, value and relative cost/SMC for different sensitivities (£2023)

Panel / Scenario / Metric	Nuclear	Total VRE	OFF	ON	PV (grid-scale)	PV (mid-scale, 10–50 kW)
Panel A. Output and output-weighted system marginal cost (SMC)						
Reference: 2030 ICs + storage, FES EU VRE						
Output (GWh/yr)	31,536	273,301	189,295	65,066	18,940	-
Output-weighted SMC (£/MWh)	£54.83	£45.06	£45.22	£41.29	£51.96	£51.96
Value ratio	1.00	0.82	0.82	0.75	0.95	0.95
2030 ICs, 2023 storage, FES EU VRE						
Output (GWh/yr)	31,536	270,457	190,814	54,187	25,456	-
Output-weighted SMC (£/MWh)	£55.64	£45.98	£46.28	£42.37	£51.43	£51.43
Value ratio	1.00	0.83	0.83	0.76	0.92	0.92
2030 ICs + storage, high EU VRE						
Output (GWh/yr)	31,536	267,346	188,774	53,553	25,018	-
Output-weighted SMC (£/MWh)	£42.46	£34.19	£34.60	£31.69	£36.47	£36.47
Value ratio	1.00	0.81	0.81	0.75	0.86	0.86
2030 ICs + storage, embedded VRE						
Output (GWh/yr)	31,536	190,366	134,295	38,168	17,902	-
Output-weighted SMC (£/MWh)	£56.39	£46.96	£47.10	£43.45	£53.30	£53.30
Value ratio	1.00	0.83	0.84	0.77	0.95	0.95
Panel B. LMCoE/SMC ratio (dimensionless, VRE only)						
2030 ICs + storage, FES EU VRE	-	-	1.48	1.8	1.03	1.53
2030 ICs, 2023 storage, FES EU VRE	-	-	1.52	1.93	1.07	1.59
2030 ICs + storage, high EU VRE	-	-	2.12	2.8	1.59	2.35
2030 ICs + storage, embedded VRE	-	-	1.6	1.62	1.02	1.51

Source: UCED model outputs and Table 7 LMCoE estimates. Notes: SMC denotes the UCED model system marginal cost; output-weighted SMC is delivered VRE output weighted by the SMC; "-" indicates not applicable. The ratio of demand-weighted to output-weighted SMC is about 1.05.

The message for appraisal is that a high-VRE portfolio must be judged on both the marginal delivered cost after curtailment and the time profile of output value. Average curtailment and nominal LCoE are useful summaries but not sufficient for efficient portfolio design.

5.4 Implications and caveats

Three implications follow. First, the value of interconnection is conditional on conditions abroad: as European VRE rises, trade relieves less curtailment, raising the premium on domestic flexibility – storage, flexible demand, perhaps electrolysis – where cost and local price signals allow it to absorb surpluses. Second, nuclear and VRE should be judged together: beyond the point at which nuclear's inertia is needed for stability, extra nuclear begins to curtail VRE, so its net contribution to emissions reduction falls, and a least-cost zero-carbon portfolio must weigh these interactions. Third, embedded VRE shifts curtailment onto the grid-visible fleet; if distributed resources cannot be controlled, they raise marginal curtailment for transmission-connected VRE, strengthening the case for better observability and control.

Some caveats are warranted. The cost assumptions (Table 6) are based on BEIS values uprated to 2023 and should be refreshed as new data become available. The SMC comparisons (Table 8) are output-weighted and comparable across technologies (less so for PV). Still, they are not at full market value, since they omit the scarcity conditions under which flexible plant earns its mark-up (which are more relevant for conventional plant). Most important, we model GB as a copper plate, so the results are best read as the equilibrium towards which the system moves once internal constraints are relaxed; those constraints are likely to bind at least to 2030, and Chyong and Newbery (2026) show that adding them amplifies c_m/c_a and raises costs further, notably in Scotland.

None of this changes the central point: once curtailment is structural, efficient investment and support design must use marginal, not average, curtailment, and these depend on the portfolio and on system flexibility. Because the levelised costs assume an unchanged pattern of curtailment, while in reality it will change as transmission, interconnection and storage are built, a high LMCoE is best read as a signal to reconsider the choice or its timing, and to let complementary infrastructure catch up.

6. Conclusions

This paper asks how much electricity an extra unit of renewable capacity delivers at high penetration and what that output costs. The answer turns on curtailment at the margin. Because spilling occurs only when the system is already in surplus, the last megawatt added is curtailed far more than the average: in a 2030 GB system modelled as a copper plate, marginal curtailment runs at roughly five to nine times the average rate. With several renewable technologies present, adding one increases the curtailment of the others, and these spillovers – together with the more productive new plant assumed here – push marginal curtailment higher still and amplify differences across technologies. The same logic applies to inflexible nuclear, whose net contribution to zero-carbon energy at high VRE penetration is less than its gross output.

These curtailment effects translate into delivered cost. The levelised cost of potential output (LCoE) understates the cost of clean electricity once curtailment is structural. The cost-relevant measures are the levelised average cost (LACoE) for the existing fleet under proportional curtailment – the right guide for free entry only where users fund the deep network reinforcement that leaves incumbents no worse off – and the levelised marginal cost (LMCoE) for incremental investment made while the network is held fixed. For GB 2030, we find LACoE only modestly above LCoE once interconnection and storage are built, but LMCoE is materially above both and rises with marginal curtailment.

Interconnection and storage both reduce curtailment and, hence, LMCoE, but their value is conditional. Interconnection relieves curtailment less when neighbouring systems are simultaneously in surplus, and storage earns most of its return from arbitrage, reserve and ancillary services rather than from curtailment relief. Curtailment, and therefore marginal cost, is a property of the whole portfolio and of the flexibility around it, not of any technology in isolation.

The policy implications are direct. Efficient investment and support design should focus on marginal, not just average, curtailment. A technology-neutral auction that ranks nominal £/MWh bids need not select the least-cost addition, and a strike price near the wholesale price does not make a technology costless to the system. Because the levelised costs computed here assume an unchanged pattern of curtailment, while transmission, interconnection and storage will change it, a high marginal cost is best read as a signal to reconsider a choice, or its timing, and to let complementary infrastructure catch up. Relaxing the copper-plate assumption – adding the internal network constraints that bind GB today – only sharpens these conclusions (Chyong and Newbery, 2026).

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Appendix A Methods

VRE curtailment

The closed economy spreadsheet model takes the same demand and VRE data as the UCED model (see below), which is based on the ESO (2024) *Hydrogen Evolution* scenario (one of the more cautious scenarios in terms of expected VRE capacity additions by 2030, retaining considerable gas-fired generation).

ESO (2024) gives 2030 assumed capacities of VRE for European countries that we also use. The hourly projections are simple scalars for each category of the 1998 hourly values (see Appendix B), preserving the hourly patterns for consistency across VRE outputs (at home and abroad) and related demand. Figure A1 shows that 2030 onshore wind has a slightly higher mean output in mid-day hours, whereas offshore wind has a slightly higher mean output in mid-morning and evening peak hours. The data Appendix B provides statistical data on correlations between different VREs.

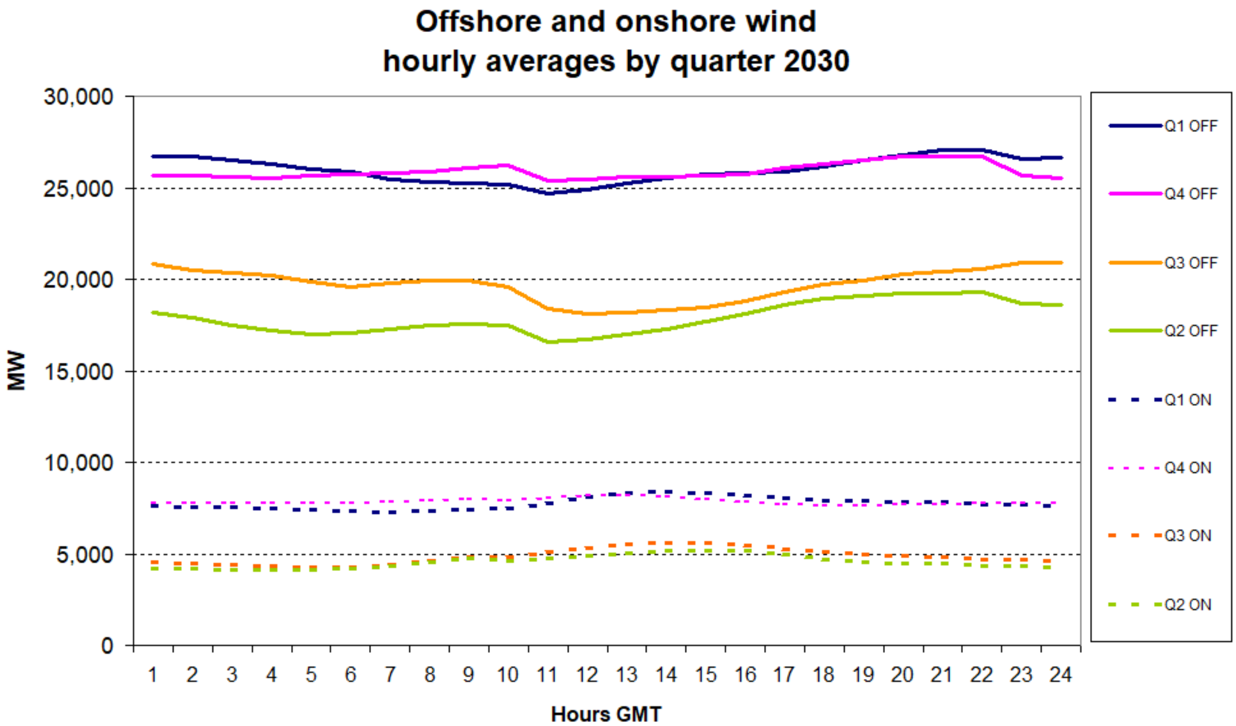

Figure A1 Quarterly averages of potential output per hour for off- and onshore wind, 2030
Source: see data Appendix B. Note: OFF is offshore wind, ON is onshore wind

The initial level of curtailment depends on the amount remaining from total demand, *D*, (which includes demand for exports, injections into pumped storage, and demand for hydrolysis) after allowing for the necessary priority dispatch of nuclear power and waste-to-energy (both of which incur costs from ramping down, in contrast to VRE). After that, the system is constrained to have no more than 90% VRE penetration to maintain adequate inertia for stability (strictly, this is a limit on Simultaneous Non-Synchronous Penetration, SNSP, which also includes imports over DC links and battery discharges, irrelevant if there is surplus VRE). Must-run spinning capacity (mainly Nuclear output), N, is needed for inertia but may be insufficient for the required minimum capacity for inertia, βD ($\beta =$ 1-SNSP). The maximum amount of VRE that can be absorbed, V_a, is D - Max(N, βD) = Max$\{D - N, (1-\beta)D\}$, and so Curtailment, K = Max(0,$V - V_a$) = Max(0, V - Min$\{D - N, (1-\beta)D\}$), where in this case β is 10%. Its allocation to the three technologies is pro-rata to the total potential output in that hour (or, if efficiently curtailed, first curtails onshore wind up to the maximum level offered, then any remaining curtailment is allocated to offshore wind, and finally to PV, in the order of decreasing avoidable cost). The annual sum gives the total curtailment for each technology, which, divided by total capacity, gives curtailment per MW and effective output per MW (potential output less curtailment).

UCED model

The UCED model, an extension of the existing model developed by Chyong and Newbery (2022), considers 19 European national electricity markets (listed in Table B.1), dividing them into 28 zones to consider key transmission constraints explicitly. Thus, GB has seven zones, Denmark has two zones, and Norway has three zones. As nodal pricing for the GB market has been ruled out by HM Government's *Review of Electricity Market Arrangements*,[9] and as it is not yet clear whether zonal pricing will be introduced, the model ignores GB transmission constraints, treating GB as a "copper plate". The impact of zonal pricing is left for future research.

[9] See https://www.gov.uk/government/publications/review-of-electricity-market-arrangements-rema-technical-research-supporting-consultation

Appendix B Data Sources for the UCED Model

Demand

The model considers 19 European national electricity markets (Table B.1), dividing them into 28 zones to explicitly consider key transmission constraints for GB (7 zones), Denmark (2 zones), and Norway (3 Zones).

Table B.1: Annual electricity demand (TWh) projection for 2030

Country	Country Code	2030
GB	GB	314.37
Austria	AT	84.35
Belgium	BE	99.47
Switzerland	CH	71.68
Czech Republic	CZ	80.96
Germany	DE	684.36
Denmark	DK	54.42
Spain	ES	286.63
Finland	FI	103.15
France	FR	516.22
Italy	IT	380.75
Luxembourg	LU	9.01
Netherlands	NL	180.39
Norway	NO	170.26
Poland	PL	197.60
Portugal	PT	60.88
Sweden	SE	168.69
SEM	SEM	52.17
Slovenia	SI	16.59

Annual electricity demand (in TWh) shown in Table B.1 was taken from *Future Energy Scenarios "Hydrogen Evolution"* (FES)[10] produced by the GB's National Energy System Operator (NESO). These annual projections were then multiplied with hourly load profiles to arrive at hourly load time series used in the dispatch model.

The hourly load profiles were taken from the PECD dataset (the 1998 climate year was chosen to represent a normal year; for details on definitions and clustering of weather years, see Ah-Voun et al., 2024) to ensure spatial correlation between the GB and European electricity markets and hourly wind and solar capacity factors (also taken from TYNDP 2022, ENTSO-E, 2022). These hourly load profiles vary by scenario and are created bottom-up based on different types of demand (such as electric vehicles, heat pumps/electric heating, etc.). For more information, see "Appendix VI: Demand" in TYNDP (2022) "Scenario Building Guidelines".[11]

[10] ESO (2024). The databook is at https://www.neso.energy/fes-data-workbook-2024; electricity demand for GB was taken from the databook, tab "ES1" and for European countries are taken from tab "ES2".

[11] https://2022.entsos-tyndp-scenarios.eu/wp-content/uploads/2022/04/TYNDP_2022_Scenario_Building_Guidelines_Version_April_2022.pdf

Generation

Electricity generation includes gas CCGTs, thermal coal, oil, biomass, hydrogen CCGTs, nuclear, solar, wind, and other renewable supplies (RES, such as marine and waste-to-energy). Gross installed capacity was taken from FES HE scenario 2030 for GB (tab "ES1") and Europe (tab "ES2"). Table B.2 reports the total installed generation capacity per country in the model.

Technoecomomic parameters such as ramp rates, minimum up and downtime, start and shut down costs, thermal efficiency, and variable operating and maintenance (non-fuel) costs of dispatchable generation were primarily taken from the ENTSO-E (2024).[12] All costs and prices used in the model are Euro 2023 prices.

Biomass, gas, coal, oil and hydrogen-based electricity generation technologies are modelled endogenously (i.e. based on their respective short-run marginal costs). In contrast, wind, solar, nuclear and other RES are modelled exogenously, assuming either near zero short-run marginal cost (for wind and solar and other RES) or must-run due to technical and high cycling costs (for nuclear).

Exogenous generation technologies include Solar PV, Offshore Wind, Onshore Wind, Nuclear, Marine, Waste, and Other Renewables. The data-sourcing approach for exogenous technologies involves sourcing data from established datasets, making adjustments for regional consistency, and calculating relevant parameters such as capacity factors, thermal efficiencies, and carbon intensities.

The installed capacities were primarily sourced from the FES (HE 2030) dataset, with solar and wind hourly capacity factor profiles obtained from the PECD dataset[13] (1998 climate year data). Profiles for Nuclear and other RES were averaged from the hourly 2015–2022 actual generation data available on the ENTSO-E Transparency Platform.

For solar technologies, the analysis distinguished between utility-scale and rooftop PV installations. Rooftop solar profiles were adjusted for utility-scale PV using a factor of 1.11 derived from Jacobson and Jadhav (2018), which accounts for differences in sunlight incidence due to panel tilt and tracking. Weighted averages were then calculated for each zone, incorporating sub-zonal capacities for utility and rooftop solar. Onshore and offshore wind capacity factor profiles were computed using installed capacity weights for each sub-zone, following a similar methodology to solar. While calculating wind profiles was less complex, it relied on accurate sub-zonal capacity splits to ensure precision in the resulting hourly capacity factor profiles.

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[12] https://eepublicdownloads.blob.core.windows.net/public-cdn-container/clean-documents/sdc-documents/ERAA/2023/ERAA2023%20PEMMDB%20Generation.xlsx. The original source for these parameters is the worksheet titled "Thermal Properties" within the Excel file named "ERAA2023 PEMMDB Generation.xlsx", derived from the Pan-European Market Modelling Database.

[13] https://zenodo.org/records/7224854

Table B.2: Electricity generation capacity by fuels in 2030 (MW)

	Biomass	Coal	Gas	Oil	Hydrogen	Other RES	Solar	Wind Onshore	Nuclear	Wind Offshore	**Total**
Austria	585		1,997	164		293	9,620	8,691			**21,349**
Belgium	668		8,772	150		452	9,590	4,396	2,077	5,805	**31,909**
Czech Republic	410	3,690	856		500		6,080	1,506	3,936		**16,978**
Denmark	2,534		628				5,029	5,479		9,730	**23,401**
Finland	1,600		2,969				3,185	14,326	3,380	7,101	**32,561**
France	2,120		12,486	1,041	500	240	38,769	29,632	60,320	4,964	**150,072**
Germany	12,110		35,604	857	500	2,100	156,298	82,128		28,021	**317,619**
Great Britain	4,227		43,414	363	1,260	5,820	27,644	23,081	4,570	43,476	**153,854**
Island of Ireland (SEM)			7,723	693		103	4,496	8,749		4,344	**26,107**
Italy	4,672		50,222				63,568	16,743		1,940	**137,145**
Netherlands	1,059		15,386				28,084	7,795	485	16,979	**69,788**
Norway	732						2,563	6,369		8,779	**18,444**
Poland	1,535	16,584	8,182				15,597	15,554		10,560	**68,012**
Portugal	700		4,016				13,490	9,751		330	**28,287**
Slovenia	23	539	460				1,768	981	696		**4,467**
Spain	1,100		18,875		200		55,227	41,035	4,104	1,680	**122,221**
Sweden	2,220						4,830	22,459	6,881	1,599	**37,989**
Switzerland	400					200	10,264	495	1,220		**12,580**
Total	**36,695**	**20,813**	**211,589**	**3,268**	**2,960**	**9,207**	**456,646**	**299,405**	**87,669**	**145,308**	**275,324**

Characteristics of GB VRE

Table B.3 gives summary statistical data about the projected GB VRE.

Table B.3 Correlations and characteristics of 2030 GB VRE

	ON	OFF	PV	VRE	tot Wind
ON	100%	84%	-8%	88%	92%
OFF	84%	100%	-18%	91%	99%
PV	-8%	-18%	100%	21%	-16%
VRE	88%	91%	21%	100%	93%
total wind	92%	99%	-16%	93%	100%
Demand closed	22%	20%	24%	29%	21%
All Demand	70%	73%	9%	78%	75%
Res D closed	-77%	-82%	-8%	-86%	-83%
Res all demand	-56%	-57%	-22%	-67%	-59%
Max to capacity	68%	89%	86%	73%	81%
CF on max output	40%	56%	14%	46%	52%

Notes: The top box gives the correlation coefficients between elements in the columns and rows, the last two lines gives first, the ratio of the maximum recorded output of each aggregate technology to its installed capacity and below the capacity factor taking the maximum observed output as the effective capacity. Demand closed is total national demand excluding demand for exports and storage, all demand is total demand including for exports and storage.
Res D is residual demand, either for the closed case or including all demand.

Thus onshore and offshore wind have a correlation coefficient of 84% but PV has a negative correlation (-16%) with all wind, showing the complementarity between wind and solar PV. VRE has a modest correlation with demand in the closed economy (29%, as wind dominates and is higher in the higher demand winter period) but a much higher correlation (78%) with total demand, showing that additional sources of demand help match VRE output. All VRE is negatively correlated with residual demand, which in turn is likely positively correlated with the wholesale price, reducing the value of VRE. This value impact is alleviated with increasing uses of surplus VRE by exports and storage. For an example of the relationship of correlations to value see Azevedo et al. (2024).

A critical issue to address before calculating LCoEs is the projected capacity factors for wind, which have dramatically changed since the previous estimates in BEIS (2020), as shown in Table B.4 below. The figures from BEIS are the potential capacity factors, while the figures from the FES HE are the average capacity factors, which will be below their potential. Capacity factors have changed dramatically in a relatively short time period as new technologies are deployed. IRENA (2019, p11) notes, “For onshore wind plants, global weighted average capacity factors would increase from 34% in 2018 to a range of 30% to 55% in 2030 and 32% to 58% in 2050. For offshore wind farms, even higher progress would be achieved, with capacity factors in the range of 36% to 58% in 2030 and 43% to 60% in 2050, compared to an average of 43% in 2018.”

Recent offshore wind developments suggest that the move to larger turbines (14 MW) has accelerated and, with them, higher CFs. A recent wind farm in Shetland has a very high CF that is effectively offshore.[14] Onshore wind farms will increasingly have to locate closer to demand to avoid grid congestion, and so will access less windy sites. Taking both considerations, a 2030 offshore wind might well exceed 60% potential PCF, but relative to the average fleet delivering in 2030, a scaling factor of 1.2 seems appropriate, or 60% of offshore wind, 34% for onshore wind.

Table B.4 Projected VRE capacity factors from UK Government

	OFF	ON	OFF	ON
	capacity	factors	output multiples of 2019	
2019 actual	51.6%	28%	1	1
BEIS(2020) for 2030	57%	34%	1.1	1.2
BEIS(2020) for 2035	**60%**	**34%**	**1.2**	**1.2**
BEIS (2023) for 2025	61%	45%	1.2	1.6
BEIS (2023) for 2030	65%	48%	1.3	1.7
FES HE for 2030	43.3%	26.5%		

Sources: BEIS (2020, 2023) ESO (2024). Figures in bold are the preferred values used in the text.
Note: The FES figures are for average (post curtailment) CFs, others are potential CFs

Storage

Conventional storage (pumped storage, hydroelectric generation with reservoir, batteries, compressed and liquid air energy storage) and demand-side response (DSR: load shifting and peak shaving) are modelled (see Table B.5).

[14] https://www.sserenewables.com/news-and-views/2023/08/final-turbine-installed-at-viking-wind-farm-in-shetland/

Table B.5: Electricity storage and demand side response capacity in 2030

	Conventional storage		**DSR**	
	Discharge, MW	**Duration,* hours**	**Discharge, MW**	**Duration*, hours**
Austria	16,463	125	1,400	14
Belgium	2,130	3	10,107	11
Czech Republic	4,105	3		
Denmark	364	8		
Finland	4,030	571	4,641	4
France	28,588	152	9,999	11
Germany	32,652	49	6,722	5
Great Britain	27,747	3	4,131	6
Island of Ireland	2,179	3	667	4
Italy	25,431	134	2,286	4
Luxembourg	62	1	90	5
Netherlands	2,362	2	1,687	4
Norway	36,303	4,786	19,713	7
Poland	3,607	2		
Portugal	8,598	271		
Slovenia	1,399	8	110	13
Spain	25,590	527	2,000	4
Sweden	16,826	1,024	3,478	19
Switzerland	18,029	303		

Notes: * average for all storage technologies

All storage and DSR assumptions are taken from FES and ERAA 2023 (ENTSOe, 2024). Table B.6 summarises GB data.

Table B.6 Storage options in 2030 FES HE Scenario

Storage type	GW	GWh
Battery, BES	22.625	40.538
LAES	0.155	0.918
CAES	0.003	0.016
PHS	3.566	44.372
BES+PS	26.191	84.910

Source: FES24 Table ES.18

Hydro energy inflow data, discharge and charge capacities for the modelled market zones are derived from the Pan-European Market Modelling Database (PEMMDB),[15] part of the ERAA2023 study. Hydro inflows are sourced from the "Storage_technology – Year Dependent" sheet in files accessible via Hydro Inflows ZIP,[16] with the reference year set to 1998 under

[15] https://eepublicdownloads.blob.core.windows.net/public-cdn-container/clean-documents/sdc-documents/ERAA/2023/ERAA2023%20PEMMDB%20Generation.xlsx

[16] https://2024.entsos-tyndp-scenarios.eu/wp-content/uploads/2024/draft2024-input-output/Hydro-Inflows.zip

normal climatic conditions. Discharge, charge, and volume capacities are obtained from the sheet "TY2030" in ERAA 2023 PEMMDB Generation.xlsx.

Assumptions and data processing for hydro and PS technologies:

- Zones with positive discharge capacity but zero volume capacity assume discharge capacity equals volume capacity.
- Efficiency losses for pumped storage are assumed to be 25%.

Battery and DSR discharge, charge, and volume capacities are primarily based on FES, supplemented by ERAA 2023 PEMMDB Generation.xlsx for non-GB zones. DSR capacities for Great Britain (GB) are sourced from FES, while for other regions, data is derived from the "TY2030" in ERAA 2023 PEMMDB Generation.xlsx. Note that we take hydro generation capacity from the PEMMDB dataset. In particular, according to the PEMMDB dataset, GB has 2,219.5 MW of hydro-run-of-river generation capacity with storage capability (pondage). Therefore, GB's total storage capacity (discharge, Table B.3) is slightly higher (1,560 MW higher) than the total storage capacity reported under the FES 2030 HE due to additions of pondage storage capacity.

Assumptions and data processing for batteries and DSR:

- GB DSR capacity values are exclusively based on FES, while other zones use PEMMDB data.
- Battery storage calculations are based on the injection/offtake ratio in TYNDP, assuming 3 hours of energy storage for zones without specific data.
- Roundtrip efficiency losses for batteries are assumed to be 15%.
- Implicit (load shifting) DSR assumes a uniform 4-hour "storage" (or shifting) capacity.
- Peak shaving is modelled in great detail following assumptions on price bands, capacity and availability hours, according to ERAA 2023 PEMMDB.

According to FES HE 2030, GB's total consumer DSR (residential, industrial, and commercial consumers) may provide up to 2.07 GW of demand reduction at its peak in 2030. Further, FES HE 2030 assumes 8.16 GW of demand flexibility from smart EV charging (1.97 GW) and flexibility from domestic and industrial heat storage, hybrid heat pumps and thermal storage. Thus, in total, GB is projected to have 10.22 GW of demand-side flexibility by 2030 in the FES HE scenario, which is rather ambitious and sits at the high end of forecasts from other stakeholders and institutions (e.g. Torriti, 2024. Carbon Trust and Imperial College London forecasts optimal DSR capacity to be between 4.1 GW and 11.4 GW by 2030). In our dispatch model, we assume 2.07 GW of implicit DSR (load shifting) and another 2.07 GW of peak shaving, totalling 4.13 GW of DSR for GB by 2030. Note that peak shaving capacity will unlikely help reduce curtailment. They are designed to reduce peak hour demand rather than provide intertemporal flexibility to shift the residual load and lower the curtailment amount.

FES reports capacity for Compressed Air and Liquid Air Storage for GB only. Their discharge, charge and volume capacities for compressed air and liquid air storage are derived from FES data. Data from other regions is unavailable. Other storage options are shown in Table B.5.

Assumptions and data processing for Compressed Air and Liquid Air Storage:

- Installed capacities for compressed and liquid air storage reported in the FES databook are treated as discharge and charge capacities.
- Discharge durations are assumed to be 3 hours for compressed air[17] and 5 hours for liquid air: see Vecchi et al. (2021).
- Roundtrip efficiency is assumed to be 57.5% for both technologies, representing the midpoint of the 45–70% range cited by Vecchi et al. (2021).

Network

The network data for interconnections between zones in the model includes Net Transfer Capacities (NTCs), their assumed hourly availability profiles, and associated losses. The primary source for this data is the Pan-European Market Modelling Database (PEMMDB), specifically the file PEMMDB_Transfer_Capacities_2030.xlsx, which contains information on both HVDC and HVAC lines for European market zones. Supplementary data was drawn from FES, Ofgem[18] and public sources to calculate interconnections between GB zones and the rest of Europe.

To create the interconnector data, only interconnections where both connected nodes are listed within the relevant zones were included in the analysis. The NTC values for these interconnections were derived directly from their rated power. Availability profiles for the interconnections were assumed to be 1 (i.e., available at all hours). Where multiple interconnections existed between the same zones, they were categorised as additional lines.

In particular, given public data and our assumptions for 2030, GB is projected to have 14,514 MW of interconnection capacity with the rest of Europe:

1. 2,400 MW with Belgium
2. 1,400 MW with Germany
3. 1,400 MW with Denmark
4. 1000 MW with Netherlands
5. 1,464 MW with Norway
6. 1,450 MW with the Island of Ireland
7. 5,400 MW with France

The final dataset includes the processed NTC values and interconnections availability profiles, incorporating the adjustments for GB sub-zones. This approach provides a robust and consistent basis for modelling interconnection capacities across the GB and European power systems.

[17] https://www.modernpowersystems.com/analysis/compressed-and-liquid-air-for-long-duration-high-capacity-11065946/

[18] https://www.ofgem.gov.uk/energy-policy-and-regulation/policy-and-regulatory-programmes/interconnectors

Costs and prices

Load curtailment cost is assumed to be €4,000/MWh-e, which aligns with the ERAA 2023 price cap assumption. A carbon price is assumed to be €50/tCO_2 in 2030 for both GB and European power markets. Fuel prices were sourced from the BEIS (2023[19]) *Electricity Generation Costs 2023* report (Table B.7).

Table B.7: Assumed fuel prices

	€2023 per MWh-th
Dedicated biomass	11.83
Biomass CHP	14.64
Biomass CCS*	22.02
Hydrogen	66.60
Diesel	79.16
Natural Gas	34.58
Thermal coal	29.48

Notes: * 2020 BEIS cost report, MWh-th is MWh of fuel (thermal content)

Assumed avoidable (variable non-fuel) cost for exogenous generation (non-dispatchable generation) was assumed as follows:

1. Other RES: €40.53/MWh-e.
2. Wave energy: €26.69/MWh-e;
3. Landfill gas: €14.83/MWh-e;
4. Hydroelectric; €10.38/MWh-e;
5. Wind onshore: €8.90/MWh-e;
6. Wind offshore: €1.48/MWh-e;
7. Solar PV: €0/MWh-e;
8. Nuclear: -€10 /MWh-e.

The negative nuclear avoidable cost is an artificial construct designed to ensure that the dispatch model curtails nuclear power only as a last resort. This assumed variable (non-fuel) cost structure prioritises curtailment of other renewable energy sources (RES) first, as they are treated as the most expensive, while solar PV and nuclear power are curtailed last. When solar PV is curtailed, the shadow price of the demand-supply constraint (system marginal cost) will be zero. However, if nuclear power is also curtailed, this value could drop to negative €10.

Costs of GB VRE

The most recent GB data from BEIS (2020) is somewhat outdated. The projected costs £(2018) are shown in Table B.8.

[19] https://assets.publishing.service.gov.uk/media/6555cb6d046ed4000d8b99bb/annex-a-additional-estimates-and-key-assumptions.xlsx

Table B.8 Annual costs for VRE in 2030 £(2018)

annual costs	OFF	ON	PV large	PV 10-50kW	PV<10kW
fixed at 3.5% £k/MWyr	£199.87	£108.60	£34.34	£50.20	£66.81
fixed at 5% £k/MWyr	£220.96	£125.70	£39.16	£58.74	£78.56
Var O&M £/MWh	£1.00	£6.00	£0.00	£0.00	£0.00

Source: BEIS (2020), with degradation rates from Table 8. To uprate to 2024 prices using the CPI index multiply by 1.25

Emissions factors for fossil fuels

Table B.9 CO_2 emissions factors (tCO_2/MWh-th)

	CCGT	CCGT-CCS*	Oil	Coal
Emissions factors, tCO_2/MWh-th	0.2052	0.0205	0.2808	0.3384

Source: UK Government conversion factors for reporting of greenhouse gas emissions.[20]

Note: MWh-th is the CO_2 content of the fuel so emissions depend on the thermal efficiency of the plant; * we assume a 90% capture rate for CCGT-CCS.

Hydrogen Demand

Hydrogen demand data is sourced from the sheet titled "Hourly H2 Data" in MMStandardOutputFile_NT2030_Plexos_CY2009_2.5_v40.xlsx. The column "Demand [MWH2] (losses included)" provides hourly demand values for relevant zones. Since the dataset contains 8736 hourly values up to 30th December, the values from 30th December are assumed to represent 31st December. This assumption ensures data continuity.

Electrolysis

Electrolysis capacity data for GB is derived from the "ES.R" sheet in FES 2024 *Data Workbook* under the parameter "Networked Electrolysis." For other zones, electrolysis data is sourced from the ERAA 2023 PEMMDB Generation.xlsx, under the parameter "Electrolyser." The techno-economic parameters for electrolysis are also included in this analysis. Electrolysis efficiency is assumed to be 70%.

Hydrogen Storage

Hydrogen storage data, including charge and discharge capacities and availability profiles, is also sourced from MMStandardOutputFile_NT2030_Plexos_CY2009_2.5_v40.xlsx. Charge and discharge profiles are derived from the columns "H2 storage charge (load) [MWH2]" and "H2 storage discharge (gen.) [MWH2]." Capacities are extracted from the "Max [MWH2]:" row.

Volume capacities are sourced from the "H2 storages" sheet, which relies on ERAA, PECD, and PEMMDB data. This information is available for download from ENTSO-E's hydrogen data repository. The volume capacities are taken from the "Max Capacity" column.

[20] https://www.gov.uk/government/collections/government-conversion-factors-for-company-reporting

Hydrogen Network

The hydrogen network data, including NTC values and profiles, is from the “Crossborder H2 exchanges” sheet in MMStandardOutputFile_NT2030_Plexos_CY2009_2.5_v40.xlsx. NTC values are extracted from the “Max [MWH2]:” row, and profiles are calculated in a manner similar to hydrogen storage, representing line-specific data.

Some complexities in the data required specific assumptions. For instance, negative profile values indicate power leaving the system, necessitating a reversal of start and end nodes. In such cases, the NTC is determined as the minimum value. Composite zones like “IB” (representing Iberia, i.e., Spain and Portugal) were split into constituent zones. For example, a composite zone, “IBIT” was divided into PT (Portugal), ES (Spain), and IT (Italy). Interconnections were manually categorised into sequences such as PT → ES → IT → final zone.

Appendix C Supplementary tables

Table C1 Simplest spreadsheet results for 2030, no storage, no exports, no flexibility

	nuclear	Total VRE	OFF	ON	PV	hours
baseline curtailment MWh	0	39,244,636	27,137,187	8,866,572	2,774,557	3,819
baseline cap MW	3,660	94,089	43,365	23,081	27,644	
av. curtailment MWh/MW, *ac*		417	626	384	100	
capacity increment MW	0	100	100	0	0	
incremented curtailment MWh		39,092,270	27,382,432	8,919,017	2,790,821	3,816
delta MWh		313,954	245,245	52,445	16,264	-3
marg curtail MWh/MW VRE, *mc*		3,140	2,452	524	163	
ratio *mc/ac*			5.02			
capacity increment MW	0	100	0	100	0	
incremented curtailment MWh		38,974,509	27,240,228	8,949,397	2,784,884	3,809
delta MWh		196,193	103,041	82,825	10,328	-10
marg curtail MWh/MW VRE, *mc*		1,962	1,030	828	103	
ratio *mc/ac*				5.11		
capacity increment MW	0	100	0	0	100	
incremented curtailment MWh		38,822,273	27,156,853	8,872,931	2,792,488	3,806
delta MWh		43,957	19,666	6,360	17,931	-13
marg curtail MWh/MW VRE, *mc*		440	197	64	179	
ratio *mc/ac*					4.38	
capacity increment MW	157	0	0	0	0	
incremented curtailment MWh		39,745,309	27,825,300	9,073,691	2,846,318	3,852
delta MWh		966,993	688,112	207,120	71,761	33
marg. curtail MWh/100MW av.		9,670	6,881	2,071	718	
capacity increment MW	0	705	277.2	147.1	281.1	
incremented curtailment MWh		40,068,088	28,028,438	9,153,223	2,886,427	3859
delta MWh		1,289,773	891,251	286,652	111,871	40
marg. curtail MWh/100MW av.		12,898	8,913	2,867	1,119	

Notes: Assumes constant nuclear output of 3,660 MW + average run-of river of 562 MW, demand includes a constant 1,962 MW electrolysis demand.

Table C1 shows the raw data from the simple closed economy spreadsheet model with no dispatchable flexibility, instead taking constant average values (as they affect inertia). Its layout shows how the compressed Table 2 is abbreviated where MWh/MW = hours/yr expressed as a percentage. Table 2 includes elements (electrolysis, run-of-river storage, energy from waste) that are dispatched in the UCED model (subject in some cases to ramp constraints) and whose hourly values has been transferred to the spreadsheet to allow a fairer comparison between the two sets of results. Table C1 ignores all flexibility (including their average values). These average additions to demand and must-run capacity relax the inertia constraint, but their lack of responsiveness to surplus VRE increases curtailment by 15% compared to Table 2. As usual, higher curtailment lowers marginal: average curtailment ratios.

Table C2 shows efficient curtailment for the same underlying data as Table 2b.

Table C.2 Efficient curtailment results for 2030 scenario, no storage, no exports

Spreadsheet model	Total VRE	OFF	ON	PV	hours
ac	4.1%	2.2%	12.7%	0.0%	40.4%
mc		35.4%	22.1%	4.3%	
mc: ac		16.3	1.7	n.a.	
MCF		24.6%	11.9%	6.7%.	
UCED model					
ac	4.0%	2.1%	12.6%	0.0%	
mc		32.3%	25.8%	4.3%	
mc: ac		15.6	2.1	n.a.	
MCF		27.7%	8.2%	6.7%	

Note: Source as for Table 2b. ON curtailed first, then OFF, finally PV

Table C3 considers the various cost measures for the two models. With efficient curtailment, onshore wind is curtailed to such an extent that it makes little economic sense to expand its capacity, and indeed, the only efficient VRE at the margin is grid-scale PV. The resulting individual cost rankings are PV<OFF<ON for all measures.

Table C3 Cost metrics with efficient curtailment, £(2018)

Spreadsheet model	OFF	ON	PV
LCoE £/MWh	£43.04	£48.20	£40.64
LACoE £/MWh	£44.62	£73.52	£40.64
LMCoE £/MWh	£103.54	£126.58	£66.42
UCED model			
LCoE £/MWh	£43.04	£48.20	£40.64
LACoE £/MWh	£44.55	£72.92	£40.64
LMCoE £/MWh	£92.16	£180.73	£66.42

Marginal curtailment and the efficient cost of clean power[1]

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Abstract

As variable renewable electricity (VRE, wind and PV) penetration increases, the additional electricity delivered by one more unit of VRE capacity is substantially smaller than either its nominal output or average production: capacity of one VRE technology increases curtailment of other VRE technologies, magnifying its impact. Consequently, investment and policy decisions should be based on marginal rather than average delivered output, implying substantially higher marginal levelised costs than conventional LCoE calculations suggest. Their magnitude is calculated for a possible 2030 British scenario in which all internal congestion has been eliminated. The potential benefit of additional exports and storage depend on the extent of Continental VRE expansion. Additional nuclear power displaces some VRE, reducing its carbon benefit but by less than expanding VRE.

Keywords: variable renewable electricity, marginal curtailment, LCoE, support design,

JEL: H23; L94; Q42; Q48

1. Introduction

As variable renewable electricity (VRE: wind and solar PV) comes to dominate, electricity systems increasingly face periods in which potential VRE output cannot be fully absorbed. The surplus must be curtailed (i.e. spilled or wasted). Curtailment is now routine: in 2024, British (mainly Scottish) wind farms had about 13% of their potential output curtailed — 10.5 TWh out of 80.7 TWh of potential wind generation, against 264 TWh of consumption. Under most support arrangements, curtailed output is compensated at the support price, so failure to deliver (curtailment) imposes material costs on final consumers. A simple way to see the cost implication is that, if, as in Scotland, some wind farms were curtailed by more than half, that would double the cost of delivered electricity. Curtailment is not a peculiarly British problem and arises for a variety of reasons, including mid-day oversupply in PV-rich systems (Halttunen et al., 2020; O'Shaughnessy et al., 2020), transmission congestion (Bird et al., 2015), and system-wide operational constraints to maintain stability (Mehigan et al., 2020).

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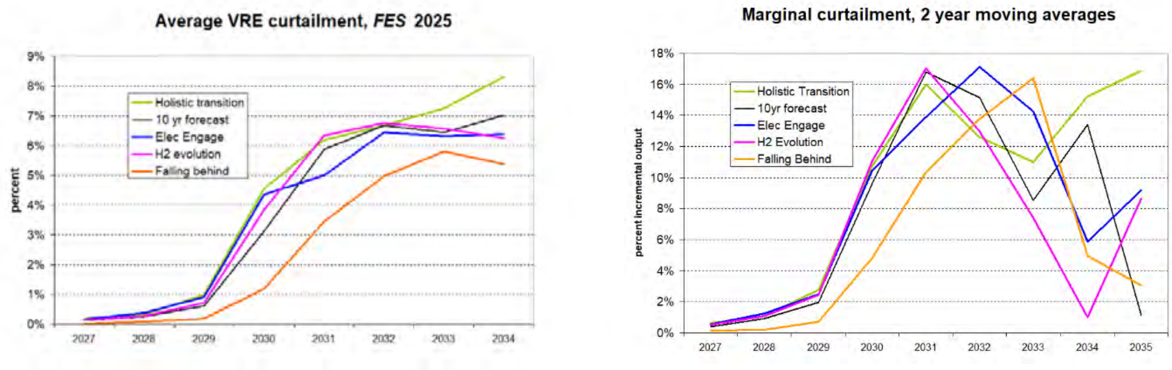
This raises a question that conventional cost comparisons sidestep. When an investor adds one more megawatt of renewable capacity, how much electricity does it actually deliver, and what does that delivered output cost? The usual answer – the levelised cost of electricity (LCoE) – assumes that all potential output is sold. Once curtailment is material, that assumption fails, and it fails differently for the average plant and for the marginal one. If a fraction of output is spilled, the cost per unit of energy actually delivered is scaled up by $1/(1 - c_a)$, where c_a is the share of output curtailed. At Great Britain (GB)'s 2024 13% average wind curtailment, delivered cost is already about 15% above the nominal LCoE – and above the price paid under GB's auctioned Contracts for Difference (CfDs).

Our central message is that even average curtailment understates the cost of expansion. Unless the transmission network is reinforced in step with new VRE, the cost-relevant quantity for an investment decision is not the average curtailment of the existing fleet but the *marginal* curtailment, c_m: the share of potential output of the last unit of capacity spilled. The long-run marginal cost of VRE then scales roughly as $1/(1 - c_m)$. Because curtailment occurs only when the system is already in surplus, the last unit added is exposed to those surplus hours far more than the average unit. For onshore wind in the Single Electricity Market (SEM) of Ireland, Newbery (2021) found that the marginal-to-average curtailment ratio, c_m/c_a, was typically above 3. The wedge between c_m and c_a is why curtailment accelerates as penetration rises when network expansion lags.

This article goes further to show that with more than one VRE technology, installing an extra MW of one technology one does not only curtail itself: by deepening the surplus in the hours it produces, it also forces the others off the system. These interactions are illustrated in Figure 3 below for a possible GB 2030 VRE portfolio. Interactions between different technologies were noted by López Prol and Zilberman (2023). They found that Californian solar penetration increased both solar and wind curtailment, and wind penetration increased solar curtailment. Novan & Wang (2024, p6) estimate that "an additional MWh of wind generation during the midday hours reduces utility-scale solar supply by 0.1 MWh. Similarly, a 1 MWh increase in small-scale solar only increases curtailment at utility-scale renewables by 0.033 MWh." The same logic extends to inflexible low-carbon plants: because spilling wind or solar is cheaper than turning down nuclear, additional nuclear running in surplus hours curtails VRE and so delivers less net-zero-carbon energy than its own output suggests. Such interactions have largely been overlooked or buried within the complexity of scenario models (e.g., NESO, 2024).

Figure 1 demonstrates why the distinction between average and marginal curtailment matters. NESO (2025) provides average curtailment year by year (Figure 1a), but does not provide marginal curtailment. The data allow this to be roughly estimated (while the underlying model would have allowed an accurate measure), as shown in Figure 1b.

Figure 1 a: Projected average and b: marginal curtailment rates, 2 yr. moving averages



Source: NESO (2025)

Notes: Note that the marginal curtailment axis is twice that of the average graph. Generation data excludes generation required to offset network constraints that would impact curtailment. *Holistic Transition* represents the fastest transition path (higher electrification rates), Electric Engagement less so, *Hydrogen Evolution* has lower electrification for heat and more fossil generation, while *Falling Behind* (Counterfactual in FES24) is what it says.

The implication is that the long-run marginal cost of delivered renewable electricity can lie well above its LCoE, and that the gap varies across technologies in ways the LCoE cannot reveal. That matters for least-cost planning and, directly, for auction design: a technology-neutral auction that ranks bids on nominal £/MWh need not select the cheapest addition once marginal curtailment and its spillovers are counted.

We quantify these effects with a unit commitment and economic dispatch (UCED) model calibrated to a plausible GB 2030 generation portfolio (NESO, 2024). We add a small increment of one technology at a time, re-solve the system, and read off the extra curtailment – for that technology and for the others. We then vary the system's flexibility: interconnection to neighbouring markets, storage, the level of European VRE, nuclear availability, and the controllability of distributed VRE. Throughout, we treat GB as a single "copper plate" with no internal transmission limits. This is deliberate: it isolates the curtailment that survives even when the internal grid has caught up with VRE – the curtailment driven by GB-wide surplus and by the need to keep enough synchronous plant running for stability – from the congestion-driven curtailment that dominates GB today, where the binding problem is the limited transfer capability from Scotland to England. A companion paper (Chyong and Newbery, 2026) adds those internal constraints and shows that they further magnify curtailment.

The article makes three contributions. First, we show that increasing investment in one VRE technology increases curtailment in all VRE technologies. That was theoretically demonstrated by Newbery (2025b) and is here quantified in a possible 2030 GB energy scenario. These spillovers magnify total marginal curtailment and reduce the net decarbonisation delivered by incremental capacity – an effect that extends to nuclear. Second, it derives long-run marginal costs for each VRE technology and shows that these LRMCs can diverge sharply from conventional LCoE rankings. Third, it quantifies how far additional uses of surplus VRE, such as exporting over expanded interconnectors and storage, reduce curtailment.

The remainder of the article is structured as follows. Section 2 reviews the literature on VRE integration, market value, and curtailment where directly relevant to the topics of this article. Section 3 sets out the definitions and methods used to compute average and marginal curtailment, as well as the implied long-run marginal cost measures. Section 4 presents results for the baseline configuration and for expanded trade and storage. Section 5 discusses implications for procurement and support design. Section 6 concludes.

2. The economics of marginal curtailment

2.1 Why the last megawatt is curtailed more than the average

Curtailment occurs only during hours when potential VRE output exceeds the system's capacity to absorb it. In every other hour, an extra MWh is sold in full. So the average MW curtails only in surplus hours, whereas the last MW added is, by construction, most exposed to those hours. This would be sharply revealed if the last entrant were the first to be curtailed and would bear the brunt of the required total curtailment. Average and marginal curtailment therefore differ – and they differ significantly.

A simple picture makes the mechanism concrete. Order the hours of the year by the size of the VRE surplus. As installed capacity V rises above the level V_0 at which surpluses first appear, the curtailed energy is roughly the area of a triangle whose height is the excess capacity ($V - V_0$) and whose width is the fraction of the year in surplus. Average curtailment is that area spread over all output; the triangle grows with the square of ($V - V_0$) but is divided by the larger base V. Adding one more MW raises the height of the triangle across its whole width, so the extra curtailment – the marginal rate – tracks the triangle's edge, not its average. The last unit is spilled far more than the typical unit.

Newbery and Biggar (2024) make this exact for a piecewise-linear surplus schedule in which new capacity is added in proportion to the existing fleet.[4] The marginal-to-average ratio is then

$$c_m/c_a = (V + V_0)/(V - V_0), \tag{1}$$

with V_0 the capacity at which curtailment begins.[5] Two comparative statics follow, and both appear in our results. Raising penetration (larger V, V_0 fixed) lowers the ratio; lowering average curtailment by deferring its onset (larger V_0) raises it. The ratio is large precisely when average curtailment is small relative to capacity – the situation a well-interconnected, high-VRE system is heading towards. NESO's own projections in Figure 1 above showed the difference between average and marginal curtailment.

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[4] Figure 3 is approximately piecewise linear.

[5]The geometric demonstration is simple. Curtailment is the area of the triangle of height $V - V_0$ and length y^* (the fraction of the year VRE is curtailed). Average curtailment is then $\frac{1}{2}(V-V_0)\cdot y^*/V$. Adding 1 MW of capacity increases the curtailment triangle by raising the base roughly y^* MW, so $c_m/c_a \approx 2V/(V-V_0)$. A more accurate estimate lets potential output increase in proportion to existing potential output, so the curtailment increase is a trapezium (added to the hypotenuse of the curtailment triangle) of area $\frac{1}{2}(1+V_0/V)\cdot y^*$ rather than y^*. The geometry is laid out in Newbery and Biggar (2025).

2.2 How one technology curtails all

When a surplus occurs, every VRE generating in that hour is curtailed. The effect of adding capacity is not confined to that technology. Suppose offshore wind expands. In the windy hours when offshore output is high, onshore wind – strongly correlated with it – is high too, and the deeper surplus spills some of that onshore output as well; any solar generating in those hours is likewise curtailed. The increase in one technology thus curtails the others. We call these cross-technology spillovers, and they are central to our results.

Spillovers depend on how each technology's output aligns with system-wide surpluses, which is why they differ across technologies. Wind and solar are negatively correlated in GB (Appendix B), so wind expansion spills relatively little solar, while solar expansion – concentrated in the same midday hours across a wide area – can spill a good deal of other solar. The upshot is that total marginal curtailment exceeds own-technology curtailment alone, and that the size of the spillover is a property of the portfolio, not of any technology in isolation. López Prol and Zilberman (2023) document the empirical counterpart in California; Newbery (2025b) provides the theory; Section 4 quantifies both for GB 2030.

The same mechanism links VRE to inflexible low-carbon plant. Nuclear output provides valuable system stability, but in surplus hours it is costlier to curtail than wind or solar, so it is the renewables that are curtailed. Additional nuclear running in those hours, therefore, curtails VRE, and its net contribution to zero-carbon electricity is less than its own generation. We return to this in Section 4.4.2.

2.3 From curtailment to delivered cost

To turn curtailment into cost, we need only a few quantities, defined here. For technology j, average curtailment $c_{a,j}$ is its curtailed energy over the year divided by its potential energy; marginal curtailment $c_{m,j}$ is the extra curtailed energy caused by a small increment of j, divided by that increment's potential energy. Crucially, this extra curtailed energy is measured system-wide: it includes the additional curtailment the increment induces on the other technologies – the spillovers of §2.2 – so the cost-relevant marginal curtailment is this system-wide quantity. It is what enters MCF in equation (3). Both are read directly from the model in Section 4.

Curtailment lowers the energy a plant delivers relative to its potential. The potential capacity factor PCF is the output a plant would achieve if nothing were spilled. After curtailment, the fleet achieves an average capacity factor ACF, and the marginal plant a marginal capacity factor MCF:

$$\mathrm{ACF}_j = (1 - c_{a,j})\cdot\mathrm{PCF}_j, \tag{2}$$

$$\mathrm{MCF}_j = (1 - c_{m,j})\cdot\mathrm{PCF}_j. \tag{3}$$

(We write c_a and c_m, not *ac* and *mc*, to avoid confusion with average and marginal cost.)

Because the fixed costs of a wind or solar plant are spread over the energy it delivers, its delivered cost moves inversely with its capacity factor. The average delivered cost therefore scales with PCF/ACF = $1/(1 - c_a)$, and the marginal delivered cost with PCF/MCF = $1/(1 - c_m)$. The last term is the heart of the paper: a marginal curtailment of, say, 40% raises the long-run marginal cost of new capacity by about two-thirds ($1/0.6 \approx 1.67$), even though construction costs and the wind or sun are unchanged. Section 5 converts these capacity-factor ratios into corresponding levelised costs and applies them to GB cost data; the intervening sections provide the curtailment numbers.

3. Model and scenarios

3.1 The model

We use a unit commitment and economic dispatch (UCED) model of the GB market and 19 neighbouring markets – 22 price zones in all – that co-optimises generation and cross-border trade subject to interconnector limits (Chyong and Newbery, 2022; Newbery and Chyong, 2025). GB itself is represented as a single copper plate, with internal transmission limits switched off. As explained in Section 1, this isolates the surplus-driven and stability-driven curtailment that remains once the internal grid has caught up with VRE from the congestion-driven curtailment that dominates GB today (the subject of Chyong and Newbery, 2026). Appendices A and B gives the model and data in full.

The experiment is the same throughout. We scale up the hourly potential-output profile of one technology so that it adds, on average, 100 MWh/hr over the year (876 GWh/yr.), re-solve the system, and record the change in curtailment, technology by technology. The increment is small relative to installed capacity – increasing it tenfold changes marginal curtailment per MW by about 3% – and the technology-by-technology effects are very nearly additive (summing three separate increments differs from a combined increment by about 0.5%). The same 100 MWh/hr increment is used for every technology and scenario. Because the increment is defined in equal potential-energy terms – not equal capacity – the resulting marginal curtailment factors are directly comparable across technologies per unit of potential energy, which is the normalisation required for the cost comparison.

3.2 What forces curtailment, and what we exclude

Two things force curtailment in the model. The first is a system-wide stability limit: because wind and solar supply none of the rotational inertia that keeps alternating-current frequency steady, instantaneous VRE is capped at 90% of system demand[6] to keep enough synchronous plant running (the mechanism, and the exact curtailment rule, are in Appendix A). The second is GB-wide surplus, when potential VRE exceeds demand even after exports and storage. In the base case, the resulting curtailment is shared across technologies pro rata to offered output; Section 5.2 and Appendix C consider efficient, cost-order curtailment instead.

What the copper-plate assumption excludes is internal congestion. The distinction is not merely definitional. Ireland's SEM, which reports the two separately, dispatched down 14% of wind in 2024 – 9.3 percentage points from transmission constraints and 4.3 from system-wide constraints (EirGrid/SONI, 2025). Modelling GB as a copper plate keeps only the second, the curtailment that survives grid reinforcement; the congestion that dominates GB today is added in Chyong and Newbery (2026) and further magnifies marginal curtailment.

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[6]We are indebted to Tim Green for the plausibility of this 2030 GB target, significantly above the present limit.

If technologies were instead curtailed by avoidable cost – onshore wind first (which has the highest variable O&M), then offshore, with PV (no avoidable cost) rarely curtailed at all – the outcome would follow from exposing VRE to efficient balancing-market prices. The market is moving in that direction: Elexon is consulting on removing distortions from CfD and Renewables Obligation support so that curtailment aligns with the bid stack merit order. However, EC guidance that no payment is due once prices reach zero could leave all VRE treated alike. The consequences for technology rankings are taken up in Section 5.2.

3.3 Scenarios

The baseline pairs the 2030 VRE capacities from the *Future Energy Scenarios* (*FES*) *Hydrogen Evolution* (*HE*) pathway (NESO, 2024) with 2023 levels of interconnection and storage – a system in which renewables have outrun their complementary ability to absorb surplus VRE. Successive scenarios then add that ability and stress it (Table 1): planned 2030 interconnection alone; interconnection plus 2030 storage; higher European VRE (which competes for the same export windows); delayed nuclear (HPC Unit 2); and embedded VRE, where 30% of renewables sit on the distribution network, invisible to the system operator and so uncurtailable. Each scenario isolates one margin of spatial or temporal flexibility while holding GB VRE capacity fixed.

Table 1. Summary of Input Assumptions across Scenarios

Input Parameter	Baseline	Interconnectors Only	Interconnectors & Storage	High EU VRE	Low Nuclear	Embedded VRE
VRE Installed Capacity (2030)	As per FES HE 2030 projections	Same as baseline	Same as baseline	Same as baseline	Same as baseline	Lower (grid only)
Interconnector Capacity	2023 levels (8.5 GW)	2030 levels (14.5 GW)	2030 levels	2030 levels	2030 levels	2030 levels
Storage Capacity	2023 level (7.4 GW)	7.4 GW	26.6 GW	26.6 GW	26.6 GW	26.6 GW
Demand Side Response (DSR)	1.3 GW	1.3 GW	2 GW	2 GW	2 GW	2 GW
Curtailment Visibility (VRE types)	All VRE controllable	Same as baseline	Same as baseline	Same as baseline	Same as baseline	Grid-connected only (70% of 2030)
European VRE Assumptions	FES HE 2030 baseline	Same as baseline	Same as baseline	NECP 2023 (higher EU VRE)	Same as baseline	Same as baseline
Nuclear Capacity	4.6 GW (HPC Units 1 & 2)	Same as baseline	Same as baseline	Same as baseline	2.5 GW (Unit 2 delayed)	Same as baseline

Notes: All scenarios use identical VRE increment modelling (average 100 MWh/hr. 876 GWh/yr.) to calculate marginal curtailment; curtailment treatment changes only in the Embedded VRE case, where 30% of VRE is uncurtailable; High EU VRE scenario increases VRE availability across interconnected EU countries in line with their National Energy and Climate Plans (NCEP), limiting GB's export potential; Low Nuclear scenario reflects commissioning delays at Hinkley Point C, reducing must-run nuclear output and altering VRE-nuclear interactions; Interconnectors & Storage case reflects full 2030 planned investment and serves as the most technologically enabled configuration.

At baseline, 93% of annual National Demand (ND) is met by non-fossil sources (98% if biomass is included). Exports amount to 11.1% of ND, with net exports at 1.9%. Demand-side response (DSR) contributes an average of only 53 MW during curtailed hours, thereby playing a negligible role in mitigating VRE surpluses. The remaining scenarios are described as they arise in Section 4.

The three technologies' output profiles differ sharply – PV is strongly diurnal, and the two wind technologies differ in persistence and season – and it is these differences that drive the spillovers of Section 2.2. Figure 2 shows them as quarterly averages of hourly potential output. Appendix B provides a fuller description of the statistical properties of GB VRE and a breakdown between onshore and offshore wind.

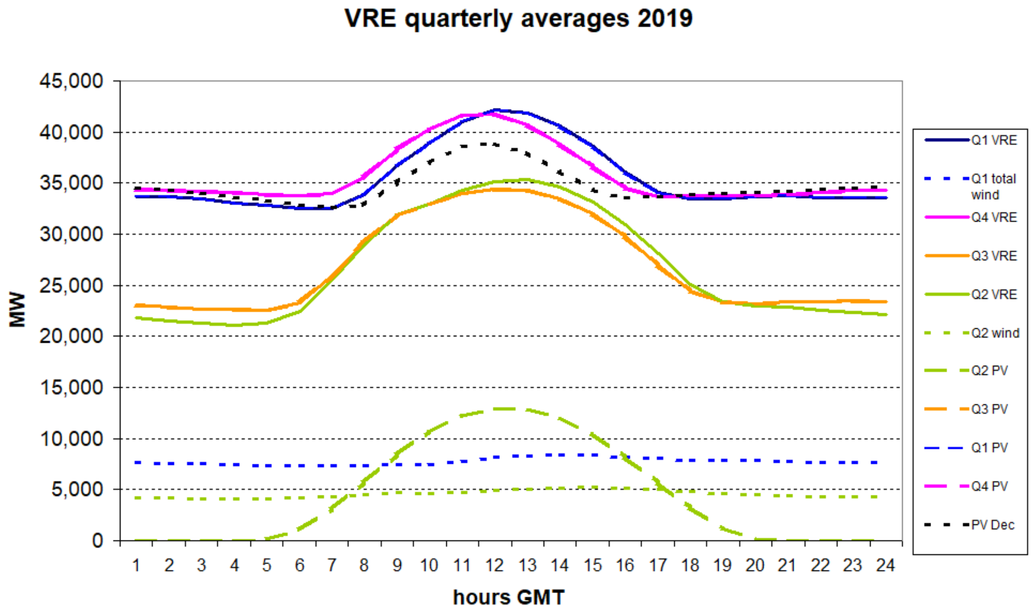

Figure 2 Quarterly averages of potential output per hour by technology and total VRE

Source: UCED outputs: Appendix A and B. Wind is combined on- and off-shore wind

4. Results

4.1 Baseline: 2030 renewables on a 2023 grid

Table 2 reports the baseline, in which 2030 VRE faces 2023 interconnection and storage. Panel A is the starting point: installed capacity, potential output, and the average curtailment c_a each technology would suffer. Offshore wind, for example, has 198,854 GWh of potential output and 14,902 GWh curtailed, an average rate of 7.5%.

Panels B–D run the increment experiment of Section 3. Each scales one technology's profile up by 100 MWh/hr (876 GWh/yr.) and re-solves; the rise in curtailment is then split into (i) the technology's own curtailment, (ii) the spillover onto each other technology, and (iii) the system-wide total (the "Total VRE" column).

Table 2. Pro-rated curtailment results for the baseline scenario (2023 storage and export capacity)

Metric	Total VRE	OFF	ON	PV	Curtailed hours
Panel A. Baseline system and average curtailment					
Baseline capacity (GW)	94.20	43.48	23.08	27.64	
Potential output (GWh/yr)	282,073	198,854	56,935	26,284	
Fleet PCF	34.2%	52.2%	28.2%	10.9%	
Potential capacity factor of new increment, PCF		60.0%	34.0%	11.0%	
Baseline curtailment (GWh)	21,338	14,902	5,021	1,415	2,548
Average curtailment, c_a	7.6%	7.5%	8.8%	5.4%	
Panel B. Increment in offshore wind (OFF)					
Capacity increment (MW)	166.7	166.7	0	0	
Potential increment (GWh/yr)	876	876	0	0	
Curtailment after increment (GWh)	21,720	15,178	5,109	1,433	2,584
Increase in curtailment (Δ), GWh	381	275	88	18	36
Marginal curtailment (% of increment)	43.5%	31.4%	10.1%	2.0%	
System-wide c_m/c_a ratio		5.81			
PCF/MCF = $1/(1 - c_{m,sys})$		1.77			
Panel C. Increment in onshore wind (ON)					
Capacity increment (MW)	294.1	0	294.1	0	
Potential increment (GWh/yr)	876	0	876	0	
Curtailment after increment (GWh)	21,805	15,231	5,132	1,442	2,588
Increase in curtailment (Δ), GWh	466	329	111	27	40
Marginal curtailment (% of increment)	53.2%	37.5%	12.7%	3.0%	
System-wide c_m/c_a ratio			6.04		
PCF/MCF = $1/(1 - c_{m,sys})$			2.14		
Panel D. Increment in solar PV (PV)					
Capacity increment (MW)	909.1	0	0	909.1	
Potential increment (GWh/yr)	876	0	0	876	
Curtailment after increment (GWh)	21,577	15,046	5,070	1,461	2,577
Increase in curtailment (Δ), GWh	239	144	49	46	29
Marginal curtailment (% of increment)	27.3%	16.5%	5.6%	5.3%	
System-wide c_m/c_a ratio				5.07	
PCF/MCF = $1/(1 - c_{m,sys})$				1.38	

Notes: c_a is average curtailment (curtailed output as a percentage of potential output). In each increment panel, one technology's hourly potential-output profile is proportionally scaled to add an average of 100 MWh/hr over the year (876 GWh/yr). The row "Marginal curtailment (% of increment)" reports the increase in curtailment as a percentage of the potential increment, decomposed by curtailed technology; the Total VRE entry is the system-wide marginal curtailment (the row sum). PCF and MCF denote potential and marginal capacity factors, with MCF = PCF$(1 - c_{m,sys})$ and PCF/MCF = $1/(1 - c_{m,sys})$. Assumed capacity factors are explained in Appendix C.

Offshore wind illustrates the decomposition. The 876 GWh/yr increment raises total curtailment by 381 GWh, a system-wide marginal curtailment of 43.5%. Of that, 31.4 points are offshore wind's own curtailment and 10.1 and 2.0 points are spillovers onto onshore wind and PV. Against an average rate of 7.5%, the marginal-to-average ratio is 5.8. The implied cost mark-up is PCF/MCF = $1/(1 - 0.435) = 1.77$: the long-run marginal cost of offshore wind is about 77% above its nominal LCoE, before any variable O&M. The onshore and PV increments tell the same story, with ratios of 6.0 and 5.1. The final column counts the curtailed hours – the periods in which the marginal value of VRE is near zero and GB-wide prices should fall to zero or below.

Two features stand out. First, average curtailment is low (7–9%) despite the large VRE build, because the copper-plate assumption removes internal congestion and leaves only the stability limit and GB-wide surplus to bind; the companion paper with internal constraints finds materially higher curtailment (Chyong and Newbery, 2026). A low c_a with a high c_m necessarily produces a high c_m/c_a. Second, the ratios here exceed the single-technology SEM estimates for two reasons. New turbines are assumed more productive than the ageing fleet – PCF 60% against the realised 2019 fleet load factor of 51.6% for offshore wind (a factor of 1.16), and 34% against 27% for onshore (1.26), benchmarked against the actual fleet in Table C.2 rather than the modelled 2030 fleet PCF of Table 2 – which, with V_0 raised, lifts c_m/c_a as Section 2.1 predicts. More importantly, the portfolio spillovers add the cross-technology terms that a single-technology calculation misses.

The marginal effects are robust (Section 3.1), but cross-technology comparisons need care, because they depend on the curtailment-ordering rule. Appendix C, Table C.2 repeats the exercise under efficient curtailment – onshore wind first, then offshore, PV last (and, in the base case, never). Total curtailment is unchanged, but its distribution across technologies, and hence the technology-specific ratios, change markedly; under that rule, PV is not curtailed at all in the base case, so a c_m/c_a for PV is not meaningful.

4.2 The impact of interconnector expansion on curtailment

GB's interconnector capacity is set to rise by about 70% by 2030, from 8.5 to 14.5 GW. Holding storage at 2023 levels, Table 3 raises interconnection to its 2030 level to isolate the value of trade alone.

Table 3. Curtailment rates and ratios, with planned interconnectors but no extra storage

Metric	Total VRE	OFF	ON	PV	Curtailed hours
Baseline curtailment with 2023 interconnectors (GWh)	21,338	14,902	5,021	1,415	2,549
Curtailment with 2030 interconnectors (GWh)	11,616	8,039	2,748	828	1,603
Reduction from interconnector expansion (GWh)	9,722	6,863	2,273	587	946
PCF/ACF = $1/(1 - c_a)$		1.04	1.05	1.03	
Curtailed hours/year (increment case)		1,615	1,615	1,602	
System-wide c_m/c_a ratio		5.97	7.40	4.92	
PCF/MCF = $1/(1 - c_{m,sys})$		1.32	1.56	1.18	

Notes: Baseline curtailment with 2023 interconnectors is repeated from Table 2 for comparison. Definitions and calculations as in Table 2. Full increment decompositions are reported in Appendix C, Table C.1

Trade is powerful in moderating curtailment. Baseline curtailment falls from 21,338 to 11,616 GWh – 9,722 GWh, or 46% – with the largest absolute fall for offshore wind and reductions for all three technologies; curtailed hours fall too, so periods of curtailment shorten as well as shrink. Average curtailment drops accordingly: PCF/ACF moves towards 1 for each technology, so delivered output approaches potential output. Marginal curtailment also falls, lowering PCF/MCF and, counterintuitively, even where cm/ca rises, the long-run marginal cost of new capacity – a result proved in Newbery (2025b). The cost ranking is unchanged (ON > OFF > PV). But the ratios stay high: trade eases the non-linearity of curtailment without removing it, and its value depends on neighbours having spare demand when GB is in surplus – the subject of Section 4.4.1.

4.3 The impact of additional storage on curtailment

Adding 2030 storage on top of 2030 interconnection isolates temporal flexibility. Storage rises from 7.4 to 21.7 GW and DSR from 1.3 to 2 GW.

Table 4. Curtailment rates and ratios, with planned interconnectors, storage and DSR

Metric	Total VRE	OFF	ON	PV	Curtailed hours
Curtailment with 2030 ICs only (GWh)	11,616	8,039	2,748	828	1,603
Curtailment with 2030 ICs + storage (GWh)	8,771	6,075	2,088	608	1,341
Reduction from storage + DSR (GWh)	2,845	1,964	660	220	262
PCF/ACF = $1/(1 - c_a)$		1.03	1.03	1.03	
System-wide marginal curtailment, $c_{m,sys}$		19.8%	27.9%	12.3%	
System-wide c_m/c_a ratio		7.44	9.18	5.41	
PCF/MCF = $1/(1 - c_{m,sys})$		1.25	1.39	1.14	

Notes: Top line is repeated from Table 3 for comparison. Definitions and calculations as in Table 2.

Curtailment falls further, from 11,616 to 8,771 GWh — another 2,845 GWh, or 24% – across all three technologies, with curtailed hours down from 1,603 to 1,341. Storage complements interconnection: one shifts surplus across space, the other across time. PCF/ACF moves closer still to one, and PCF/MCF falls again, lowering long-run marginal cost for every technology. Figure 3 shows the resulting curtailment curves, ranked by total curtailment; the way the technologies stack and interact is the visual counterpart of the spillovers in Section 2.2.

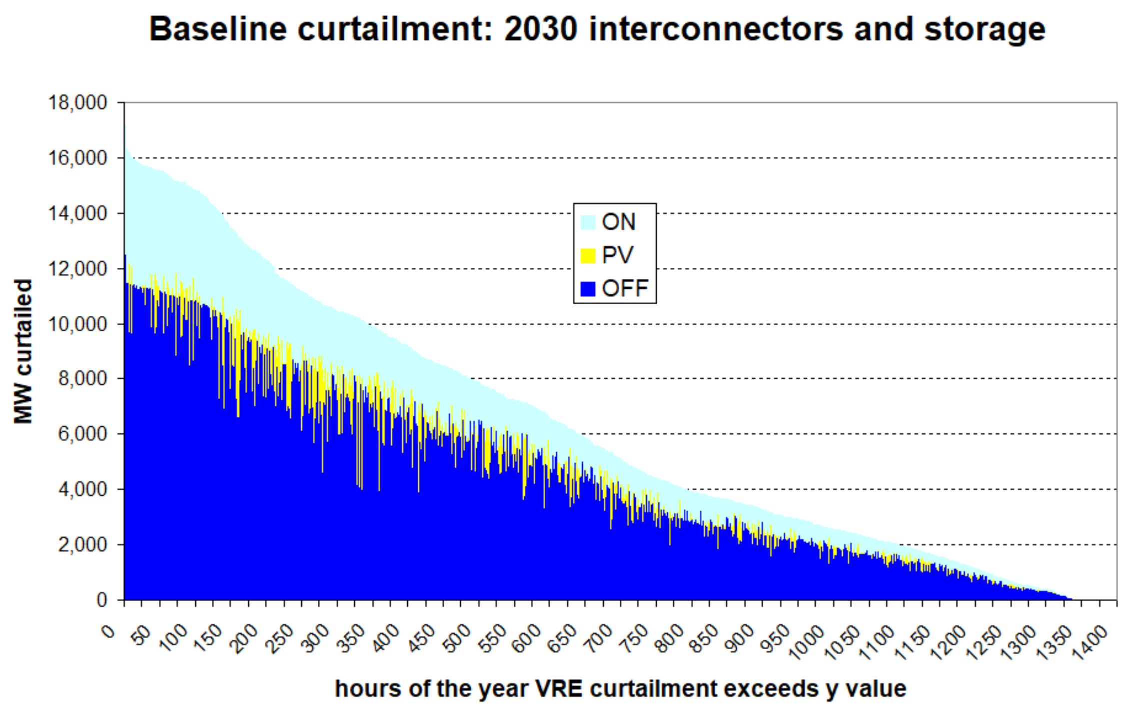

Figure 3 Curtailment curves for 2030 with planned interconnectors and storage ranked by total curtailment

Notes: Technologies ranked by total, pro-rata curtailment, 2030 storage & interconnector capacity. OFF is Offshore wind, ON is onshore wind and PV is Solar PV.
Source: as for Table 4.

The curtailment savings, however, are only a small part of what storage is worth. The extra 14.3 GW of storage and 0.7 GW of DSR (about 15 GW of flexibility) cut curtailment by 2,845 GWh and curtailed hours by 262. A four-hour battery fleet discharging for four hours a day would shift roughly 21,900 GWh/yr — nearly eight times the curtailment it would relieve. Valued against CCGT at a carbon-inclusive £145/MWh, the 2,845 GWh saving is worth about £411 million a year, or some £28/kW-yr across the 15 GW. Against the NREL (2023) mid-estimate of roughly £950/kW for a 2030 four-hour battery (2022 prices), curtailment relief alone covers only a small share of annualised capital cost: storage must earn most of its return from arbitrage, reserve and ancillary services, not from reducing curtailment.

4.4 Sensitivities: higher EU VRE, lower nuclear output, embedded VRE

Table 5 examines the implications for curtailment and cost of higher EU VRE, lower nuclear output and the consequences of an inability to curtail embedded (typically household and distribution-connected) VRE

Table 5. Capacities, outputs and curtailment under sensitivity cases

Metric	Nuclear	Total VRE	OFF	ON	PV	Curtailed hours
Panel A. Reference case: 2030 interconnectors + storage (FES EU VRE)						
Capacity (GW)	4.6	94.2	43.48	23.08	27.64	
Curtailment (GWh)		8,771	6,075	2,088	608	1,341
Output (GWh/yr)	31,536	273,301				
PCF/ACF = $1/(1 - c_a)$			1.03	1.03	1.03	
System-wide c_m/c_a ratio			7.44	9.18	5.41	
PCF/MCF = $1/(1 - c_{m,sys})$			1.25	1.39	1.14	
Panel B. High EU VRE (NECP-based European VRE expansion)						
Output (GWh/yr)	31,536	267,346				
Curtailment (GWh)		14,727	10,079	3,382	1,266	1,859
PCF/ACF = $1/(1 - c_a)$			1.05	1.05	1.05	
System-wide c_m/c_a ratio			6.1	8.2	4.0	
PCF/MCF = $1/(1 - c_{m,sys})$			1.37	1.68	1.24	
Panel C. Lower nuclear output (HPC delayed)						
Nuclear capacity (GW)	2.5	94.2	43.5	23.1	27.6	
Curtailment (GWh)		7,369	5,123	1,748	498	1,141
Output (GWh/yr)	20,012	274,704				
Change relative to reference (GWh/yr)	-11,524.2	-1,402.7	-951.9	-340.6	-110.2	-200
VRE curtailment per MWh of nuclear output change		12.2%				
Panel D. Embedded VRE (partial non-curtailability of embedded resources)						
Grid-connected capacity (GW)	4.6	65.9	30.4	16.2	19.4	
Grid output (GWh/yr)	31,536	197,451	139,197	39,854	18,399	
Embedded VRE output (GWh/yr)		84,622	59,656	17,080	7,885	
Grid-curtailed VRE (GWh)		7,085	4,909	1,681	495	1,234
PCF/ACF = $1/(1 - c_a)$			1.03	1.04	1.03	
System-wide c_m/c_a ratio			13.6	9.6	7.3	
PCF/MCF = $1/(1 - c_{m,sys})$			1.41	1.31	1.16	

Notes: Panel A repeats 2030 interconnectors + storage from Table 4. Definitions and calculations as in Table 2. In Panel C the "Change relative to reference" row is not homogeneous across columns: the Nuclear figure is the change in nuclear output (the reduction from delaying HPC Unit 2), the Total VRE, OFF, ON and PV figures are changes in curtailment (a negative value is a fall in curtailment, and hence a rise in delivered VRE), and the final figure is the change in curtailed hours.

4.4.1 Higher EU VRE output

Interconnection only relieves curtailment if neighbours can absorb the surplus. Replacing the FES view of European VRE with the more ambitious *National Energy and Climate Plans* (*NECP*) – Figure 4 – and holding GB unchanged, total GB curtailment rises from 8,771 to 14,727 GWh (+68%), with curtailed hours up from 1,341 to 1,859. All technologies are affected, PV most, reflecting the coincidence of midday solar across interconnected systems. Marginal curtailment rises but by less than average: PCF/MCF goes from 1.25 to 1.37 (offshore), 1.39 to 1.68 (onshore) and 1.14 to 1.24 (PV). Onshore costs rise most, as most European wind is onshore. The lesson is that the case for more interconnection to Europe is not automatic: when European VRE is high and correlated with GB's, export windows narrow, and domestic flexibility – storage above all – matters more.

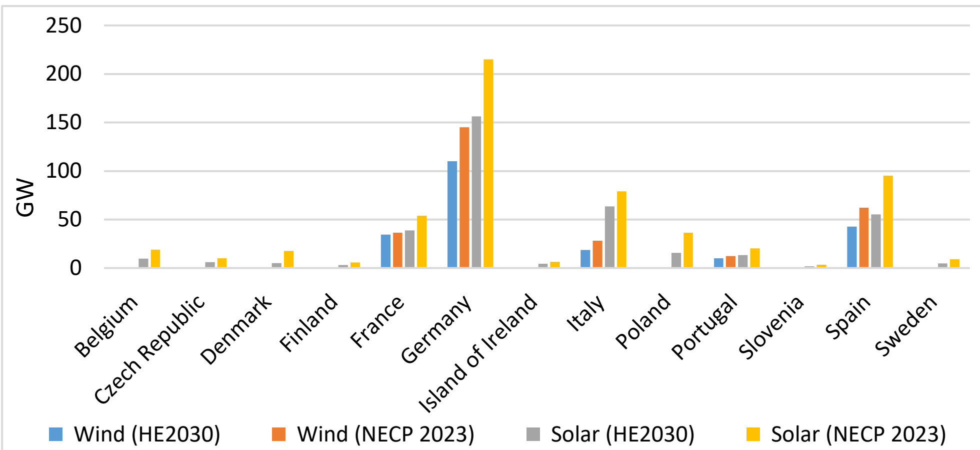

Figure 4 Projected wind and solar capacities for selected European countries under the *FES HE2030* baseline scenario and the *NECP 2023* high EU VRE scenario

Sources: (NESO 2024); NECP 2023 from: https://ember-energy.org/data/live-eu-necp-tracker

4.4.2. Lower nuclear output

In the reference case, nuclear supplies low-carbon, synchronous output, but in surplus hours it is costlier to turn down than VRE, so it adds to curtailment (Section 2.2). Cutting 2030 nuclear from 4.6 to 2.5 GW (HPC Unit 2 delayed) with everything else held constant, lowers total VRE curtailment from 8,771 to 7,369 GWh and curtailed hours from 1,341 to 1,141. The trade-off in delivered zero-carbon energy is the focus. Nuclear output falls by 11,524 GWh/yr, but because VRE curtailment falls, VRE delivery rises, so total zero-carbon output falls by only 10,121 GWh/yr. Put the other way, had Unit 2 run, its 11,524 GWh would have added only 10,121 GWh of net zero-carbon energy – about 88% of its output – the rest displaced as extra VRE curtailment. The relevant figure for appraising nuclear at high VRE penetration is this net contribution, not gross output. Flexibility in low-carbon plants, as discussed by Cany et al. (2018) and Mezősi et al. (2020), directly affects this margin.

4.4.3 Embedded VRE

Not all VRE is visible to or controllable by the operator – a gap GB's system operator has flagged as urgent[7] – because much onshore wind and most PV connect at distribution level. If this embedded output cannot be curtailed, it acts as a reduction in demand rather than as dispatchable supply, and the adjustment falls on the grid-connected fleet. Treating a uniform 30% of each technology as embedded and uncurtailable, grid-curtailed VRE is 7,085 GWh over 1,234 hours, and curtailment concentrates on the shrinking curtailable base. The resulting PCF/MCF markups are 1.41 (offshore), 1.31 (onshore), and 1.16 (PV)—above their baseline values for offshore wind and PV, while for onshore wind the markup is slightly below baseline, even though its c_m/c_a ratio rises. Making the embedded share uncurtailable lifts the ratio of marginal to average curtailment for all three technologies, as a smaller grid-connected base absorbs the same system adjustment.

This has both an operational and an economic reading. While embedded VRE is a must-take, the measured marginal curtailment for grid-connected technologies overstates the burden those technologies impose on their own, since part of it stems from uncurtailable embedded output. The remedy is not to discount the curtailment result but to improve the visibility, controllability and local flexibility of distributed resources, so that the adjustment need not fall so heavily on transmission-connected VRE.

5. Cost and policy implications

5.1 Which cost measure for which decision

Section 2.3 expressed delivered cost ratios as capacity factors; here, we translate them into money. Table 6 gives the cost assumptions – BEIS (2020) capital and O&M, uprated to 2023 prices – and the resulting LCoE at potential output: £62.48/MWh for offshore wind, £63.63 onshore, £53.67 for grid-scale PV (£79.53 mid-scale).

Table 6. Input cost assumptions for LCoE, LACoE and LMCoE calculations (£2023)

Cost input / parameter	OFF	ON	PV (grid-scale)	PV (mid-scale)
Potential capacity factor, PCF	60%	34%	11%	11%
Lifetime (years)	30	25	35	30
Degradation (%/yr)	1.0%	0.8%	0.5%	0.5%
Annualised fixed cost, F_j (5% real; £/kWyr)	£268.32	£152.64	£47.55	£71.33
Fixed-cost component at PCF (£/MWh)	£58.84	£56.34	£53.67	£79.53
Variable O&M, v_j (£/MWh)	£3.64	£7.29	£0.00	£0.00
LCoE at PCF (£/MWh)	**£62.48**	**£63.63**	**£53.67**	**£79.53**

Source: BEIS (2020) cost assumptions, uprated from 2018 to 2023 prices using CPI. Note: Mid-scale PV is 10–50 kW.

[7] https://www.neso.energy/about/innovation/our-innovation-projects/der-visibility-and-probabilistic-modelling

The LCoE assumes every potential megawatt-hour is delivered. With curtailment it must be adjusted, and which adjustment depends on the question. Annualising the fixed cost F_j over delivered rather than potential output gives the levelised average and marginal costs of delivered VRE:

$$\text{LCoE} = F_j /(8760 \cdot \text{PCF}_j) + v_j,$$

$$\text{LACoE} = F_j /(8760 \cdot \text{ACF}_j) + v_j, \quad (4)$$

$$\text{LMCoE} = F_j /(8760 \cdot \text{MCF}_j) + v_j, \quad (5)$$

where v_j is variable O&M (near zero except for wind). Setting $v_j = 0$,

$$\text{LACoE/LCoE} = \text{PCF}_j/\text{ACF}_j = 1/(1 - c_{a,j}), \quad (6)$$

$$\text{LMCoE/LCoE} = \text{PCF}_j/\text{MCF}_j = 1/(1 - c_{m,j}). \quad (7)$$

LACoE is the right measure for the existing fleet under proportional curtailment, and LMCoE for an incremental investment made while the network is held fixed (Engineering "system-LCoE" studies instead add integration costs – balancing, reserves, networks, backup – to the LCoE (Ueckerdt et al., 2013; Zerrahn and Schill, 2017); marginal curtailment is a distinct, and here often dominant, term.) These levelised costs should be read with care: in every case they assume an unchanged future pattern of curtailment, whereas investment in interconnection and storage is meant to reduce it. They are best treated as indicators of which technologies to prioritise and which to delay until that complementary investment arrives.

Table 7 applies equations (4)– (7) across the scenarios.

Table 7. Levelised cost estimates for VRE in 2030 (£2023)

2023 ICs & Storage, 2030 VRE	OFF	ON	PV	PV-mid
LCoE £/MWh	£62.48	£63.63	£53.67	£79.53
LACoE £/MWh, pro-rata curtailment	£66.57	£68.10	£56.77	£84.12
LMCoE £/MWh, pro-rata curtailment	£80.72	£94.05	£63.33	£93.85
LACoE £/MWh, efficient curtailment	£63.07	£85.48	£53.67	£79.53
LMCoE £/MWh, efficient curtailment	£107.78	£127.77	£73.80	£109.35
2023 storage, 2030 ICs & 2030 VRE				
LACoE £/MWh, pro-rata curtailment	£64.61	£66.05	£55.17	£81.76
LMCoE £/MWh, pro-rata curtailment	£81.31	£95.18	£63.33	£93.85
2030 ICs, Storage & FES EU VRE				
LACoE £/MWh, pro-rata curtailment	£64.09	£65.34	£55.17	£81.76
LMCoE £/MWh, pro-rata curtailment	£77.19	£85.60	£61.72	£91.46
2030 ICs, Storage, high EU VRE				
LACoE £/MWh, pro-rata curtailment	£65.15	£66.60	£56.23	£83.32
LMCoE £/MWh, pro-rata curtailment	£84.25	£101.94	£66.55	£98.62
2030 ICs, Storage, embedded VRE				
LACoE £/MWh, pro-rata curtailment	£64.30	£65.69	£55.17	£81.76
LMCoE £/MWh, pro-rata curtailment	£86.60	£81.10	£62.26	£92.25

Source: Tables 2–6. PV is grid-scale; PV-mid is 10–50 kW scale.

By 2030, average curtailment is low once interconnection and storage are built, so LACoE exceeds LCoE only modestly (3–5%). Newbery and Biggar (2025) show that in a new Renewable Energy Zone whose users pay for the deep network reinforcement that leaves incumbents no worse off, free entry guided by LACoE would be efficient. As expected, marginal curtailment is considerably higher than average curtailment: in every scenario, LMCoE is materially above both LCoE and LACoE, and rises with the marginal curtailment rate.

The distinction has implications for market design. Until 2020, CfD auctions priced output in £/MWh and compensated curtailment, so bidders could base bids on the LCoE.[8] Since 2020, VRE earns nothing when the GB-wide price falls to zero – which is when the system-wide curtailment modelled here occurs – so a bidder facing average curtailment on the wholesale market should bid the LACoE, while one facing non-firm access, or entering a saturated system as the marginal unit, should bid the LMCoE (as with the unsubsidised merchant entry of Simshauser and Newbery, 2024). The gap between LCoE and LMCoE in Table 7 is large across all technologies and widens as marginal curtailment increases. A technology can look competitive on LCoE yet be considerably more expensive at the margin.

5.2 Technology rankings and auction design

Table 7 shows that the ranking of technologies depends on the measure used. Rankings based on LCoE — or even LACoE — can differ from those based on LMCoE, the measure relevant to incremental procurement in a high-curtailment system. A technology-neutral auction that compares only nominal £/MWh bids may therefore not pick the least-cost addition from the system's point of view: two bids at the same strike price can carry very different marginal curtailment, and hence different LMCoE, once spillovers are included – most sharply where technologies differ in output timing and in their correlation with system surpluses, as offshore wind, onshore wind and PV do. This spillover is an externality: under pro-rata access an entrant internalises only its own incremental curtailment, so the bid it can profitably make reflects a private LMCoE that omits the extra curtailment it imposes on incumbents – the socially relevant comparison uses the full system-wide LMCoE, including those spillovers. Diallo and Kitzing (2020) make the related point that technology-neutral auctions can select socially less valuable technologies when several compete for the same price-independent support. However, they base their argument on the Market or Value LCoE discussed below and ignore marginal curtailment central to our argument.

This also questions the claim that some recent auctions are "subsidy-free". A strike price near the forward wholesale price does not make a technology costless to the system, nor the least-cost marginal addition; the relevant comparison is the cost of delivered marginal zero-carbon output, not of potential output. If curtailment is allocated efficiently rather than pro rata, the rankings shift again. While PV plainly has zero avoidable cost, the ranking of avoidable costs between onshore and offshore wind is less clear: most sources report only £ or $/kWyr operating

[8] https://assets.publishing.service.gov.uk/media/5fbc72958fa8f559e887e4f8/cfd-proposed-amendments-scheme-2020-ar4-government-response.pdf

costs (e.g. IRENA, 2025), whereas BEIS (2020), used here, separates fixed (£/MW-yr) from variable (£/MWh) O&M and shows onshore wind with the higher variable cost.

5.3 The marginal value of flexibility, and the value of output

Interconnection and storage both lower curtailment but in different ways, and both lower LMCoE because both lower marginal curtailment. Their value, though, is conditional. Interconnection's curtailment relief is reduced when neighbouring systems are in surplus at the same time (Section 4.4.1): its capacity remains unchanged, but its use for relieving curtailment does not. Spatial spreading still helps – output correlations fall with distance, improving the match of surplus to demand (Halttunen et al., 2020; Olauson and Bergkvist, 2016) – but surplus hours are increasingly correlated across space as European VRE rises. Storage remains useful in that setting, yet, as Section 4.3 showed, curtailment relief is only a modest part of its value; most of its value comes from arbitrage, reserves, and ancillary services.

Costs are only half the comparison: output is worth different amounts at different times. Table 8 reports each technology's market value as its output-weighted system marginal cost (SMC) – the price it would earn in non-stress hours in a competitive market – and a value ratio relative to the time-weighted SMC, which is one for a baseload plant. Cannibalisation, where VRE depresses prices in the hours it saturates, shows up as a value ratio below one 1 (Hirth, 2012 and Diallo and Kitzing, 2020 formalise this as the value factor used above). The wind value ratios are fairly stable across scenarios; PV's is more sensitive, falling as the scarcity mark-up on flexible plant rises. The SMC is not a complete value measure — it omits ancillary-service revenue and the scarcity mark-ups that flexible plant needs to recover capital — but those matter little for VRE, so the SMC is informative for comparing VRE technologies. Panel B's LMCoE/SMC ratio combines the two sides: technologies with similar nominal costs can have very different cost-to-value ratios once curtailment and timing are factored in.

Table 8. Output, value and relative cost/SMC for different sensitivities (£2023)

Panel / Scenario / Metric	Nuclear	Total VRE	OFF	ON	PV (grid-scale)	PV (mid-scale, 10–50 kW)
Panel A. Output and output-weighted system marginal cost (SMC)						
Reference: 2030 ICs + storage, FES EU VRE						
Output (GWh/yr)	31,536	273,301	189,295	65,066	18,940	-
Output-weighted SMC (£/MWh)	£54.83	£45.06	£45.22	£41.29	£51.96	£51.96
Value ratio	1.00	0.82	0.82	0.75	0.95	0.95
2030 ICs, 2023 storage, FES EU VRE						
Output (GWh/yr)	31,536	270,457	190,814	54,187	25,456	-
Output-weighted SMC (£/MWh)	£55.64	£45.98	£46.28	£42.37	£51.43	£51.43
Value ratio	1.00	0.83	0.83	0.76	0.92	0.92
2030 ICs + storage, high EU VRE						
Output (GWh/yr)	31,536	267,346	188,774	53,553	25,018	-
Output-weighted SMC (£/MWh)	£42.46	£34.19	£34.60	£31.69	£36.47	£36.47
Value ratio	1.00	0.81	0.81	0.75	0.86	0.86
2030 ICs + storage, embedded VRE						
Output (GWh/yr)	31,536	190,366	134,295	38,168	17,902	-
Output-weighted SMC (£/MWh)	£56.39	£46.96	£47.10	£43.45	£53.30	£53.30
Value ratio	1.00	0.83	0.84	0.77	0.95	0.95
Panel B. LMCoE/SMC ratio (dimensionless, VRE only)						
2030 ICs + storage, FES EU VRE	-	-	1.48	1.8	1.03	1.53
2030 ICs, 2023 storage, FES EU VRE	-	-	1.52	1.93	1.07	1.59
2030 ICs + storage, high EU VRE	-	-	2.12	2.8	1.59	2.35
2030 ICs + storage, embedded VRE	-	-	1.6	1.62	1.02	1.51

Source: UCED model outputs and Table 7 LMCoE estimates. Notes: SMC denotes the UCED model system marginal cost; output-weighted SMC is delivered VRE output weighted by the SMC; “-” indicates not applicable. The ratio of demand-weighted to output-weighted SMC is about 1.05.

The message for appraisal is that a high-VRE portfolio must be judged on both the marginal delivered cost after curtailment and the time profile of output value. Average curtailment and nominal LCoE are useful summaries but not sufficient for efficient portfolio design.

5.4 Implications and caveats

Three implications follow. First, the value of interconnection is conditional on conditions abroad: as European VRE rises, trade relieves less curtailment, raising the premium on domestic flexibility – storage, flexible demand, perhaps electrolysis – where cost and local price signals allow it to absorb surpluses. Second, nuclear and VRE should be judged together: beyond the point at which nuclear’s inertia is needed for stability, extra nuclear begins to curtail VRE, so its net contribution to emissions reduction falls, and a least-cost zero-carbon portfolio must weigh these interactions. Third, embedded VRE shifts curtailment onto the grid-visible fleet; if distributed resources cannot be controlled, they raise marginal curtailment for transmission-connected VRE, strengthening the case for better observability and control.

Some caveats are warranted. The cost assumptions (Table 6) are based on BEIS values uprated to 2023 and should be refreshed as new data become available. The SMC comparisons (Table 8) are output-weighted and comparable across technologies (less so for PV). Still, they are not at full market value, since they omit the scarcity conditions under which flexible plant earns its mark-up (which are more relevant for conventional plant). Most important, we model GB as a copper plate, so the results are best read as the equilibrium towards which the system moves once internal constraints are relaxed; those constraints are likely to bind at least to 2030, and Chyong and Newbery (2026) show that adding them amplifies c_m/c_a and raises costs further, notably in Scotland.

None of this changes the central point: once curtailment is structural, efficient investment and support design must use marginal, not average, curtailment, and these depend on the portfolio and on system flexibility. Because the levelised costs assume an unchanged pattern of curtailment, while in reality it will change as transmission, interconnection and storage are built, a high LMCoE is best read as a signal to reconsider the choice or its timing, and to let complementary infrastructure catch up.

6. Conclusions

This paper asks how much electricity an extra unit of renewable capacity delivers at high penetration and what that output costs. The answer turns on curtailment at the margin. Because spilling occurs only when the system is already in surplus, the last megawatt added is curtailed far more than the average: in a 2030 GB system modelled as a copper plate, marginal curtailment runs at roughly five to nine times the average rate. With several renewable technologies present, adding one increases the curtailment of the others, and these spillovers – together with the more productive new plant assumed here – push marginal curtailment higher still and amplify differences across technologies. The same logic applies to inflexible nuclear, whose net contribution to zero-carbon energy at high VRE penetration is less than its gross output.

These curtailment effects translate into delivered cost. The levelised cost of potential output (LCoE) understates the cost of clean electricity once curtailment is structural. The cost-relevant measures are the levelised average cost (LACoE) for the existing fleet under proportional curtailment – the right guide for free entry only where users fund the deep network reinforcement that leaves incumbents no worse off – and the levelised marginal cost (LMCoE) for incremental investment made while the network is held fixed. For GB 2030, we find LACoE only modestly above LCoE once interconnection and storage are built, but LMCoE is materially above both and rises with marginal curtailment.

Interconnection and storage both reduce curtailment and, hence, LMCoE, but their value is conditional. Interconnection relieves curtailment less when neighbouring systems are simultaneously in surplus, and storage earns most of its return from arbitrage, reserve and ancillary services rather than from curtailment relief. Curtailment, and therefore marginal cost, is a property of the whole portfolio and of the flexibility around it, not of any technology in isolation.

The policy implications are direct. Efficient investment and support design should focus on marginal, not just average, curtailment. A technology-neutral auction that ranks nominal £/MWh bids need not select the least-cost addition, and a strike price near the wholesale price does not make a technology costless to the system. Because the levelised costs computed here assume an unchanged pattern of curtailment, while transmission, interconnection and storage will change it, a high marginal cost is best read as a signal to reconsider a choice, or its timing, and to let complementary infrastructure catch up. Relaxing the copper-plate assumption – adding the internal network constraints that bind GB today – only sharpens these conclusions (Chyong and Newbery, 2026).

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Appendix A Methods

VRE curtailment

The closed economy spreadsheet model takes the same demand and VRE data as the UCED model (see below), which is based on the ESO (2024) *Hydrogen Evolution* scenario (one of the more cautious scenarios in terms of expected VRE capacity additions by 2030, retaining considerable gas-fired generation).

ESO (2024) gives 2030 assumed capacities of VRE for European countries that we also use. The hourly projections are simple scalars for each category of the 1998 hourly values (see Appendix B), preserving the hourly patterns for consistency across VRE outputs (at home and abroad) and related demand. Figure A1 shows that 2030 onshore wind has a slightly higher mean output in mid-day hours, whereas offshore wind has a slightly higher mean output in mid-morning and evening peak hours. The data Appendix B provides statistical data on correlations between different VREs.

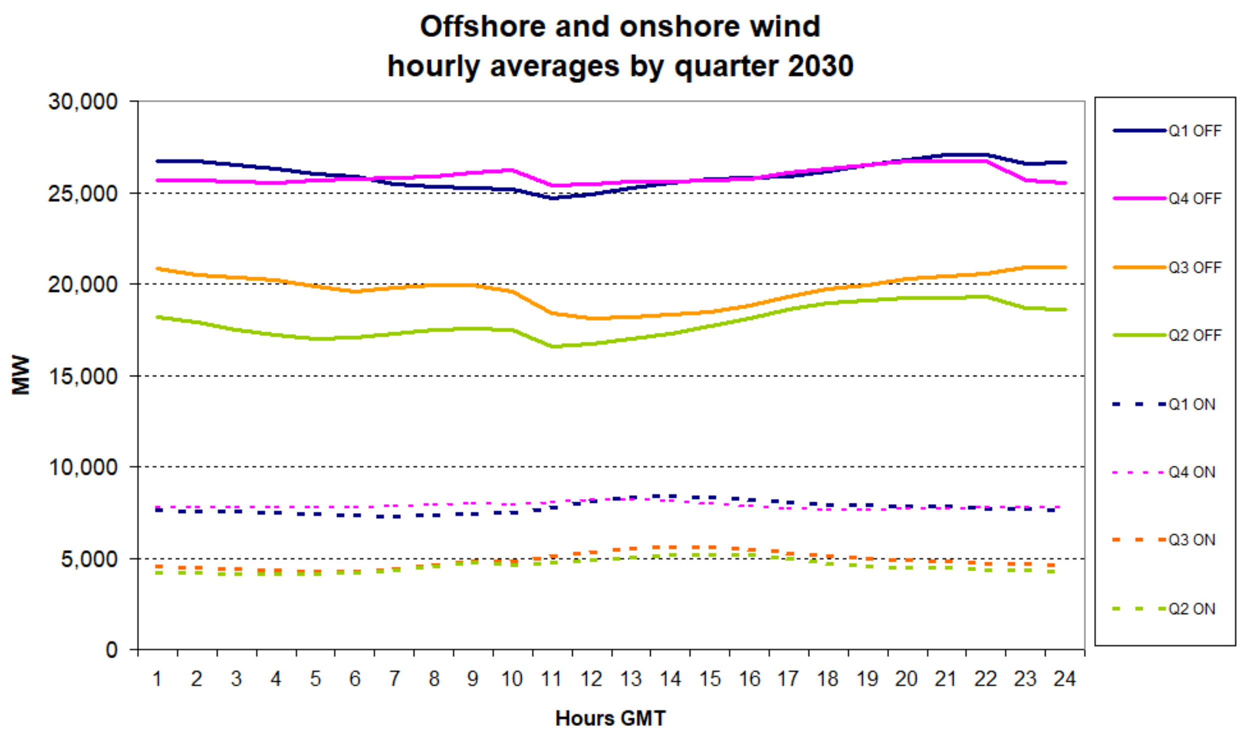

Figure A1 Quarterly averages of potential output per hour for off- and onshore wind, 2030

Source: see data Appendix B. Note: OFF is offshore wind, ON is onshore wind

The initial level of curtailment depends on the amount remaining from total demand, *D*, (which includes demand for exports, injections into pumped storage, and demand for hydrolysis) after allowing for the necessary priority dispatch of nuclear power and waste-to-energy (both of which incur costs from ramping down, in contrast to VRE). After that, the system is constrained to have no more than 90% VRE penetration to maintain adequate inertia for stability (strictly, this is a limit on Simultaneous Non-Synchronous Penetration, SNSP, which also includes imports over DC links and battery discharges, irrelevant if there is surplus VRE). Must-run spinning capacity (mainly Nuclear output), N, is needed for inertia but may be insufficient for the required minimum capacity for inertia, βD ($\beta =$ 1-SNSP). The maximum amount of VRE that can be absorbed, V_a, is D - Max(N, βD) = Max$\{D - N, (1-\beta)D\}$, and so Curtailment, K = Max(0,V - V_a) = Max(0, V - Min$\{D - N, (1-\beta)D\}$), where in this case β is 10%. Its allocation to the three technologies is pro-rata to the total potential output in that hour (or, if efficiently curtailed, first curtails onshore wind up to the maximum level offered, then any remaining curtailment is allocated to offshore wind, and finally to PV, in the order of decreasing avoidable cost). The annual sum gives the total curtailment for each technology, which, divided by total capacity, gives curtailment per MW and effective output per MW (potential output less curtailment).

UCED model

The UCED model, an extension of the existing model developed by Chyong and Newbery (2022), considers 19 European national electricity markets (listed in Table B.1), dividing them into 28 zones to consider key transmission constraints explicitly. Thus, GB has seven zones, Denmark has two zones, and Norway has three zones. As nodal pricing for the GB market has been ruled out by HM Government's *Review of Electricity Market Arrangements*,[9] and as it is not yet clear whether zonal pricing will be introduced, the model ignores GB transmission constraints, treating GB as a "copper plate". The impact of zonal pricing is left for future research.

[9] See https://www.gov.uk/government/publications/review-of-electricity-market-arrangements-rema-technical-research-supporting-consultation

Appendix B Data Sources for the UCED Model

Demand

The model considers 19 European national electricity markets (Table B.1), dividing them into 28 zones to explicitly consider key transmission constraints for GB (7 zones), Denmark (2 zones), and Norway (3 Zones).

Table B.1: Annual electricity demand (TWh) projection for 2030

Country	Country Code	2030
GB	GB	314.37
Austria	AT	84.35
Belgium	BE	99.47
Switzerland	CH	71.68
Czech Republic	CZ	80.96
Germany	DE	684.36
Denmark	DK	54.42
Spain	ES	286.63
Finland	FI	103.15
France	FR	516.22
Italy	IT	380.75
Luxembourg	LU	9.01
Netherlands	NL	180.39
Norway	NO	170.26
Poland	PL	197.60
Portugal	PT	60.88
Sweden	SE	168.69
SEM	SEM	52.17
Slovenia	SI	16.59

Annual electricity demand (in TWh) shown in Table B.1 was taken from *Future Energy Scenarios "Hydrogen Evolution"* (FES)[10] produced by the GB's National Energy System Operator (NESO). These annual projections were then multiplied with hourly load profiles to arrive at hourly load time series used in the dispatch model.

The hourly load profiles were taken from the PECD dataset (the 1998 climate year was chosen to represent a normal year; for details on definitions and clustering of weather years, see Ah-Voun et al., 2024) to ensure spatial correlation between the GB and European electricity markets and hourly wind and solar capacity factors (also taken from TYNDP 2022, ENTSO-E, 2022). These hourly load profiles vary by scenario and are created bottom-up based on different types of demand (such as electric vehicles, heat pumps/electric heating, etc.). For more information, see "Appendix VI: Demand" in TYNDP (2022) "Scenario Building Guidelines".[11]

[10] ESO (2024). The databook is at https://www.neso.energy/fes-data-workbook-2024; electricity demand for GB was taken from the databook, tab "ES1" and for European countries are taken from tab "ES2".

[11] https://2022.entsos-tyndp-scenarios.eu/wp-content/uploads/2022/04/TYNDP_2022_Scenario_Building_Guidelines_Version_April_2022.pdf

Generation

Electricity generation includes gas CCGTs, thermal coal, oil, biomass, hydrogen CCGTs, nuclear, solar, wind, and other renewable supplies (RES, such as marine and waste-to-energy). Gross installed capacity was taken from FES HE scenario 2030 for GB (tab "ES1") and Europe (tab "ES2"). Table B.2 reports the total installed generation capacity per country in the model.

Technoecomomic parameters such as ramp rates, minimum up and downtime, start and shut down costs, thermal efficiency, and variable operating and maintenance (non-fuel) costs of dispatchable generation were primarily taken from the ENTSO-E (2024).[12] All costs and prices used in the model are Euro 2023 prices.

Biomass, gas, coal, oil and hydrogen-based electricity generation technologies are modelled endogenously (i.e. based on their respective short-run marginal costs). In contrast, wind, solar, nuclear and other RES are modelled exogenously, assuming either near zero short-run marginal cost (for wind and solar and other RES) or must-run due to technical and high cycling costs (for nuclear).

Exogenous generation technologies include Solar PV, Offshore Wind, Onshore Wind, Nuclear, Marine, Waste, and Other Renewables. The data-sourcing approach for exogenous technologies involves sourcing data from established datasets, making adjustments for regional consistency, and calculating relevant parameters such as capacity factors, thermal efficiencies, and carbon intensities.

The installed capacities were primarily sourced from the FES (HE 2030) dataset, with solar and wind hourly capacity factor profiles obtained from the PECD dataset[13] (1998 climate year data). Profiles for Nuclear and other RES were averaged from the hourly 2015–2022 actual generation data available on the ENTSO-E Transparency Platform.

For solar technologies, the analysis distinguished between utility-scale and rooftop PV installations. Rooftop solar profiles were adjusted for utility-scale PV using a factor of 1.11 derived from Jacobson and Jadhav (2018), which accounts for differences in sunlight incidence due to panel tilt and tracking. Weighted averages were then calculated for each zone, incorporating sub-zonal capacities for utility and rooftop solar. Onshore and offshore wind capacity factor profiles were computed using installed capacity weights for each sub-zone, following a similar methodology to solar. While calculating wind profiles was less complex, it relied on accurate sub-zonal capacity splits to ensure precision in the resulting hourly capacity factor profiles.

[12] https://eepublicdownloads.blob.core.windows.net/public-cdn-container/clean-documents/sdc-documents/ERAA/2023/ERAA2023%20PEMMDB%20Generation.xlsx. The original source for these parameters is the worksheet titled "Thermal Properties" within the Excel file named "ERAA2023 PEMMDB Generation.xlsx", derived from the Pan-European Market Modelling Database.

[13] https://zenodo.org/records/7224854

Table B.2: Electricity generation capacity by fuels in 2030 (MW)

	Biomass	Coal	Gas	Oil	Hydrogen	Other RES	Solar	Wind Onshore	Nuclear	Wind Offshore	**Total**
Austria	585		1,997	164		293	9,620	8,691			**21,349**
Belgium	668		8,772	150		452	9,590	4,396	2,077	5,805	**31,909**
Czech Republic	410	3,690	856		500		6,080	1,506	3,936		**16,978**
Denmark	2,534		628				5,029	5,479		9,730	**23,401**
Finland	1,600		2,969				3,185	14,326	3,380	7,101	**32,561**
France	2,120		12,486	1,041	500	240	38,769	29,632	60,320	4,964	**150,072**
Germany	12,110		35,604	857	500	2,100	156,298	82,128		28,021	**317,619**
Great Britain	4,227		43,414	363	1,260	5,820	27,644	23,081	4,570	43,476	**153,854**
Island of Ireland (SEM)			7,723	693		103	4,496	8,749		4,344	**26,107**
Italy	4,672		50,222				63,568	16,743		1,940	**137,145**
Netherlands	1,059		15,386				28,084	7,795	485	16,979	**69,788**
Norway	732						2,563	6,369		8,779	**18,444**
Poland	1,535	16,584	8,182				15,597	15,554		10,560	**68,012**
Portugal	700		4,016				13,490	9,751		330	**28,287**
Slovenia	23	539	460				1,768	981	696		**4,467**
Spain	1,100		18,875		200		55,227	41,035	4,104	1,680	**122,221**
Sweden	2,220						4,830	22,459	6,881	1,599	**37,989**
Switzerland	400					200	10,264	495	1,220		**12,580**
Total	**36,695**	**20,813**	**211,589**	**3,268**	**2,960**	**9,207**	**456,646**	**299,405**	**87,669**	**145,308**	**275,324**

Characteristics of GB VRE

Table B.3 gives summary statistical data about the projected GB VRE.

Table B.3 Correlations and characteristics of 2030 GB VRE

	ON	OFF	PV	VRE	tot Wind
ON	100%	84%	-8%	88%	92%
OFF	84%	100%	-18%	91%	99%
PV	-8%	-18%	100%	21%	-16%
VRE	88%	91%	21%	100%	93%
total wind	92%	99%	-16%	93%	100%
Demand closed	22%	20%	24%	29%	21%
All Demand	70%	73%	9%	78%	75%
Res D closed	-77%	-82%	-8%	-86%	-83%
Res all demand	-56%	-57%	-22%	-67%	-59%
Max to capacity	68%	89%	86%	73%	81%
CF on max output	40%	56%	14%	46%	52%

Notes: The top box gives the correlation coefficients between elements in the columns and rows, the last two lines gives first, the ratio of the maximum recorded output of each aggregate technology to its installed capacity and below the capacity factor taking the maximum observed output as the effective capacity. Demand closed is total national demand excluding demand for exports and storage, all demand is total demand including for exports and storage.
Res D is residual demand, either for the closed case or including all demand.

Thus onshore and offshore wind have a correlation coefficient of 84% but PV has a negative correlation (-16%) with all wind, showing the complementarity between wind and solar PV. VRE has a modest correlation with demand in the closed economy (29%, as wind dominates and is higher in the higher demand winter period) but a much higher correlation (78%) with total demand, showing that additional sources of demand help match VRE output. All VRE is negatively correlated with residual demand, which in turn is likely positively correlated with the wholesale price, reducing the value of VRE. This value impact is alleviated with increasing uses of surplus VRE by exports and storage. For an example of the relationship of correlations to value see Azevedo et al. (2024).

A critical issue to address before calculating LCoEs is the projected capacity factors for wind, which have dramatically changed since the previous estimates in BEIS (2020), as shown in Table B.4 below. The figures from BEIS are the potential capacity factors, while the figures from the FES HE are the average capacity factors, which will be below their potential. Capacity factors have changed dramatically in a relatively short time period as new technologies are deployed. IRENA (2019, p11) notes, “For onshore wind plants, global weighted average capacity factors would increase from 34% in 2018 to a range of 30% to 55% in 2030 and 32% to 58% in 2050. For offshore wind farms, even higher progress would be achieved, with capacity factors in the range of 36% to 58% in 2030 and 43% to 60% in 2050, compared to an average of 43% in 2018.”

Recent offshore wind developments suggest that the move to larger turbines (14 MW) has accelerated and, with them, higher CFs. A recent wind farm in Shetland has a very high CF that is effectively offshore.[14] Onshore wind farms will increasingly have to locate closer to demand to avoid grid congestion, and so will access less windy sites. Taking both considerations, a 2030 offshore wind might well exceed 60% potential PCF, but relative to the average fleet delivering in 2030, a scaling factor of 1.2 seems appropriate, or 60% of offshore wind, 34% for onshore wind.

Table B.4 Projected VRE capacity factors from UK Government

	OFF	ON	OFF	ON
	capacity	factors	output multiples of 2019	
2019 actual	51.6%	28%	1	1
BEIS(2020) for 2030	57%	34%	1.1	1.2
BEIS(2020) for 2035	**60%**	**34%**	**1.2**	**1.2**
BEIS (2023) for 2025	61%	45%	1.2	1.6
BEIS (2023) for 2030	65%	48%	1.3	1.7
FES HE for 2030	43.3%	26.5%		

Sources: BEIS (2020, 2023) ESO (2024). Figures in bold are the preferred values used in the text.
Note: The FES figures are for average (post curtailment) CFs, others are potential CFs

Storage

Conventional storage (pumped storage, hydroelectric generation with reservoir, batteries, compressed and liquid air energy storage) and demand-side response (DSR: load shifting and peak shaving) are modelled (see Table B.5).

[14] https://www.sserenewables.com/news-and-views/2023/08/final-turbine-installed-at-viking-wind-farm-in-shetland/

Table B.5: Electricity storage and demand side response capacity in 2030

	Conventional storage		**DSR**	
	Discharge, MW	**Duration,* hours**	**Discharge, MW**	**Duration*, hours**
Austria	16,463	125	1,400	14
Belgium	2,130	3	10,107	11
Czech Republic	4,105	3		
Denmark	364	8		
Finland	4,030	571	4,641	4
France	28,588	152	9,999	11
Germany	32,652	49	6,722	5
Great Britain	27,747	3	4,131	6
Island of Ireland	2,179	3	667	4
Italy	25,431	134	2,286	4
Luxembourg	62	1	90	5
Netherlands	2,362	2	1,687	4
Norway	36,303	4,786	19,713	7
Poland	3,607	2		
Portugal	8,598	271		
Slovenia	1,399	8	110	13
Spain	25,590	527	2,000	4
Sweden	16,826	1,024	3,478	19
Switzerland	18,029	303		

Notes: * average for all storage technologies

All storage and DSR assumptions are taken from FES and ERAA 2023 (ENTSOe, 2024). Table B.6 summarises GB data.

Table B.6 Storage options in 2030 FES HE Scenario

Storage type	GW	GWh
Battery, BES	22.625	40.538
LAES	0.155	0.918
CAES	0.003	0.016
PHS	3.566	44.372
BES+PS	26.191	84.910

Source: FES24 Table ES.18

Hydro energy inflow data, discharge and charge capacities for the modelled market zones are derived from the Pan-European Market Modelling Database (PEMMDB),[15] part of the ERAA2023 study. Hydro inflows are sourced from the “Storage_technology – Year Dependent” sheet in files accessible via Hydro Inflows ZIP,[16] with the reference year set to 1998 under

[15] https://eepublicdownloads.blob.core.windows.net/public-cdn-container/clean-documents/sdc-documents/ERAA/2023/ERAA2023%20PEMMDB%20Generation.xlsx
[16] https://2024.entsos-tyndp-scenarios.eu/wp-content/uploads/2024/draft2024-input-output/Hydro-Inflows.zip

normal climatic conditions. Discharge, charge, and volume capacities are obtained from the sheet "TY2030" in ERAA 2023 PEMMDB Generation.xlsx.

Assumptions and data processing for hydro and PS technologies:

- Zones with positive discharge capacity but zero volume capacity assume discharge capacity equals volume capacity.
- Efficiency losses for pumped storage are assumed to be 25%.

Battery and DSR discharge, charge, and volume capacities are primarily based on FES, supplemented by ERAA 2023 PEMMDB Generation.xlsx for non-GB zones. DSR capacities for Great Britain (GB) are sourced from FES, while for other regions, data is derived from the "TY2030" in ERAA 2023 PEMMDB Generation.xlsx. Note that we take hydro generation capacity from the PEMMDB dataset. In particular, according to the PEMMDB dataset, GB has 2,219.5 MW of hydro-run-of-river generation capacity with storage capability (pondage). Therefore, GB's total storage capacity (discharge, Table B.3) is slightly higher (1,560 MW higher) than the total storage capacity reported under the FES 2030 HE due to additions of pondage storage capacity.

Assumptions and data processing for batteries and DSR:

- GB DSR capacity values are exclusively based on FES, while other zones use PEMMDB data.
- Battery storage calculations are based on the injection/offtake ratio in TYNDP, assuming 3 hours of energy storage for zones without specific data.
- Roundtrip efficiency losses for batteries are assumed to be 15%.
- Implicit (load shifting) DSR assumes a uniform 4-hour "storage" (or shifting) capacity.
- Peak shaving is modelled in great detail following assumptions on price bands, capacity and availability hours, according to ERAA 2023 PEMMDB.

According to FES HE 2030, GB's total consumer DSR (residential, industrial, and commercial consumers) may provide up to 2.07 GW of demand reduction at its peak in 2030. Further, FES HE 2030 assumes 8.16 GW of demand flexibility from smart EV charging (1.97 GW) and flexibility from domestic and industrial heat storage, hybrid heat pumps and thermal storage. Thus, in total, GB is projected to have 10.22 GW of demand-side flexibility by 2030 in the FES HE scenario, which is rather ambitious and sits at the high end of forecasts from other stakeholders and institutions (e.g. Torriti, 2024. Carbon Trust and Imperial College London forecasts optimal DSR capacity to be between 4.1 GW and 11.4 GW by 2030). In our dispatch model, we assume 2.07 GW of implicit DSR (load shifting) and another 2.07 GW of peak shaving, totalling 4.13 GW of DSR for GB by 2030. Note that peak shaving capacity will unlikely help reduce curtailment. They are designed to reduce peak hour demand rather than provide intertemporal flexibility to shift the residual load and lower the curtailment amount.

FES reports capacity for Compressed Air and Liquid Air Storage for GB only. Their discharge, charge and volume capacities for compressed air and liquid air storage are derived from FES data. Data from other regions is unavailable. Other storage options are shown in Table B.5.

Assumptions and data processing for Compressed Air and Liquid Air Storage:

- Installed capacities for compressed and liquid air storage reported in the FES databook are treated as discharge and charge capacities.
- Discharge durations are assumed to be 3 hours for compressed air[17] and 5 hours for liquid air: see Vecchi et al. (2021).
- Roundtrip efficiency is assumed to be 57.5% for both technologies, representing the midpoint of the 45–70% range cited by Vecchi et al. (2021).

Network

The network data for interconnections between zones in the model includes Net Transfer Capacities (NTCs), their assumed hourly availability profiles, and associated losses. The primary source for this data is the Pan-European Market Modelling Database (PEMMDB), specifically the file PEMMDB_Transfer_Capacities_2030.xlsx, which contains information on both HVDC and HVAC lines for European market zones. Supplementary data was drawn from FES, Ofgem[18] and public sources to calculate interconnections between GB zones and the rest of Europe.

To create the interconnector data, only interconnections where both connected nodes are listed within the relevant zones were included in the analysis. The NTC values for these interconnections were derived directly from their rated power. Availability profiles for the interconnections were assumed to be 1 (i.e., available at all hours). Where multiple interconnections existed between the same zones, they were categorised as additional lines.

In particular, given public data and our assumptions for 2030, GB is projected to have 14,514 MW of interconnection capacity with the rest of Europe:

1. 2,400 MW with Belgium
2. 1,400 MW with Germany
3. 1,400 MW with Denmark
4. 1000 MW with Netherlands
5. 1,464 MW with Norway
6. 1,450 MW with the Island of Ireland
7. 5,400 MW with France

The final dataset includes the processed NTC values and interconnections availability profiles, incorporating the adjustments for GB sub-zones. This approach provides a robust and consistent basis for modelling interconnection capacities across the GB and European power systems.

[17] https://www.modernpowersystems.com/analysis/compressed-and-liquid-air-for-long-duration-high-capacity-11065946/

[18] https://www.ofgem.gov.uk/energy-policy-and-regulation/policy-and-regulatory-programmes/interconnectors

Costs and prices

Load curtailment cost is assumed to be €4,000/MWh-e, which aligns with the ERAA 2023 price cap assumption. A carbon price is assumed to be €50/tCO_2 in 2030 for both GB and European power markets. Fuel prices were sourced from the BEIS (2023[19]) *Electricity Generation Costs 2023* report (Table B.7).

Table B.7: Assumed fuel prices

	€2023 per MWh-th
Dedicated biomass	11.83
Biomass CHP	14.64
Biomass CCS*	22.02
Hydrogen	66.60
Diesel	79.16
Natural Gas	34.58
Thermal coal	29.48

Notes: * 2020 BEIS cost report, MWh-th is MWh of fuel (thermal content)

Assumed avoidable (variable non-fuel) cost for exogenous generation (non-dispatchable generation) was assumed as follows:

1. Other RES: €40.53/MWh-e.
2. Wave energy: €26.69/MWh-e;
3. Landfill gas: €14.83/MWh-e;
4. Hydroelectric; €10.38/MWh-e;
5. Wind onshore: €8.90/MWh-e;
6. Wind offshore: €1.48/MWh-e;
7. Solar PV: €0/MWh-e;
8. Nuclear: -€10 /MWh-e.

The negative nuclear avoidable cost is an artificial construct designed to ensure that the dispatch model curtails nuclear power only as a last resort. This assumed variable (non-fuel) cost structure prioritises curtailment of other renewable energy sources (RES) first, as they are treated as the most expensive, while solar PV and nuclear power are curtailed last. When solar PV is curtailed, the shadow price of the demand-supply constraint (system marginal cost) will be zero. However, if nuclear power is also curtailed, this value could drop to negative €10.

Costs of GB VRE

The most recent GB data from BEIS (2020) is somewhat outdated. The projected costs £(2018) are shown in Table B.8.

[19] https://assets.publishing.service.gov.uk/media/6555cb6d046ed4000d8b99bb/annex-a-additional-estimates-and-key-assumptions.xlsx

Table B.8 Annual costs for VRE in 2030 £(2018)

annual costs	OFF	ON	PV large	PV 10-50kW	PV<10kW
fixed at 3.5% £k/MWyr	£199.87	£108.60	£34.34	£50.20	£66.81
fixed at 5% £k/MWyr	£220.96	£125.70	£39.16	£58.74	£78.56
Var O&M £/MWh	£1.00	£6.00	£0.00	£0.00	£0.00

Source: BEIS (2020), with degradation rates from Table 8. To uprate to 2024 prices using the CPI index multiply by 1.25

Emissions factors for fossil fuels

Table B.9 CO_2 emissions factors (tCO_2/MWh-th)

	CCGT	CCGT-CCS*	Oil	Coal
Emissions factors, tCO_2/MWh-th	0.2052	0.0205	0.2808	0.3384

Source: UK Government conversion factors for reporting of greenhouse gas emissions.[20]
Note: MWh-th is the CO_2 content of the fuel so emissions depend on the thermal efficiency of the plant; * we assume a 90% capture rate for CCGT-CCS.

Hydrogen Demand

Hydrogen demand data is sourced from the sheet titled “Hourly H2 Data” in MMStandardOutputFile_NT2030_Plexos_CY2009_2.5_v40.xlsx. The column “Demand [MWH2] (losses included)” provides hourly demand values for relevant zones. Since the dataset contains 8736 hourly values up to 30th December, the values from 30th December are assumed to represent 31st December. This assumption ensures data continuity.

Electrolysis

Electrolysis capacity data for GB is derived from the “ES.R” sheet in FES 2024 *Data Workbook* under the parameter “Networked Electrolysis.” For other zones, electrolysis data is sourced from the ERAA 2023 PEMMDB Generation.xlsx, under the parameter “Electrolyser.” The techno-economic parameters for electrolysis are also included in this analysis. Electrolysis efficiency is assumed to be 70%.

Hydrogen Storage

Hydrogen storage data, including charge and discharge capacities and availability profiles, is also sourced from MMStandardOutputFile_NT2030_Plexos_CY2009_2.5_v40.xlsx. Charge and discharge profiles are derived from the columns “H2 storage charge (load) [MWH2]” and “H2 storage discharge (gen.) [MWH2].” Capacities are extracted from the “Max [MWH2]:” row.

Volume capacities are sourced from the “H2 storages” sheet, which relies on ERAA, PECD, and PEMMDB data. This information is available for download from ENTSO-E’s hydrogen data repository. The volume capacities are taken from the “Max Capacity” column.

[20] https://www.gov.uk/government/collections/government-conversion-factors-for-company-reporting

Hydrogen Network

The hydrogen network data, including NTC values and profiles, is from the "Crossborder H2 exchanges" sheet in MMStandardOutputFile_NT2030_Plexos_CY2009_2.5_v40.xlsx. NTC values are extracted from the "Max [MWH2]:" row, and profiles are calculated in a manner similar to hydrogen storage, representing line-specific data.

Some complexities in the data required specific assumptions. For instance, negative profile values indicate power leaving the system, necessitating a reversal of start and end nodes. In such cases, the NTC is determined as the minimum value. Composite zones like "IB" (representing Iberia, i.e., Spain and Portugal) were split into constituent zones. For example, a composite zone, "IBIT" was divided into PT (Portugal), ES (Spain), and IT (Italy). Interconnections were manually categorised into sequences such as PT → ES → IT → final zone.

Appendix C Supplementary tables

Table C1 Simplest spreadsheet results for 2030, no storage, no exports, no flexibility

	nuclear	Total VRE	OFF	ON	PV	hours
baseline curtailment MWh	0	39,244,636	27,137,187	8,866,572	2,774,557	3,819
baseline cap MW	3,660	94,089	43,365	23,081	27,644	
av. curtailment MWh/MW, *ac*		417	626	384	100	
capacity increment MW	0	100	100	0	0	
incremented curtailment MWh		39,092,270	27,382,432	8,919,017	2,790,821	3,816
delta MWh		313,954	245,245	52,445	16,264	-3
marg curtail MWh/MW VRE, *mc*		3,140	2,452	524	163	
ratio *mc/ac*			5.02			
capacity increment MW	0	100	0	100	0	
incremented curtailment MWh		38,974,509	27,240,228	8,949,397	2,784,884	3,809
delta MWh		196,193	103,041	82,825	10,328	-10
marg curtail MWh/MW VRE, *mc*		1,962	1,030	828	103	
ratio *mc/ac*				5.11		
capacity increment MW	0	100	0	0	100	
incremented curtailment MWh		38,822,273	27,156,853	8,872,931	2,792,488	3,806
delta MWh		43,957	19,666	6,360	17,931	-13
marg curtail MWh/MW VRE, *mc*		440	197	64	179	
ratio *mc/ac*					4.38	
capacity increment MW	157	0	0	0	0	
incremented curtailment MWh		39,745,309	27,825,300	9,073,691	2,846,318	3,852
delta MWh		966,993	688,112	207,120	71,761	33
marg. curtail MWh/100MW av.		9,670	6,881	2,071	718	
capacity increment MW	0	705	277.2	147.1	281.1	
incremented curtailment MWh		40,068,088	28,028,438	9,153,223	2,886,427	3859
delta MWh		1,289,773	891,251	286,652	111,871	40
marg. curtail MWh/100MW av.		12,898	8,913	2,867	1,119	

Notes: Assumes constant nuclear output of 3,660 MW + average run-of river of 562 MW, demand includes a constant 1,962 MW electrolysis demand.

Table C1 shows the raw data from the simple closed economy spreadsheet model with no dispatchable flexibility, instead taking constant average values (as they affect inertia). Its layout shows how the compressed Table 2 is abbreviated where MWh/MW = hours/yr expressed as a percentage. Table 2 includes elements (electrolysis, run-of-river storage, energy from waste) that are dispatched in the UCED model (subject in some cases to ramp constraints) and whose hourly values has been transferred to the spreadsheet to allow a fairer comparison between the two sets of results. Table C1 ignores all flexibility (including their average values). These average additions to demand and must-run capacity relax the inertia constraint, but their lack of responsiveness to surplus VRE increases curtailment by 15% compared to Table 2. As usual, higher curtailment lowers marginal: average curtailment ratios.

Table C2 shows efficient curtailment for the same underlying data as Table 2b.

Table C.2 Efficient curtailment results for 2030 scenario, no storage, no exports

Spreadsheet model	Total VRE	OFF	ON	PV	hours
ac	4.1%	2.2%	12.7%	0.0%	40.4%
mc		35.4%	22.1%	4.3%	
mc: ac		16.3	1.7	n.a.	
MCF		24.6%	11.9%	6.7%.	
UCED model					
ac	4.0%	2.1%	12.6%	0.0%	
mc		32.3%	25.8%	4.3%	
mc: ac		15.6	2.1	n.a.	
MCF		27.7%	8.2%	6.7%	

Note: Source as for Table 2b. ON curtailed first, then OFF, finally PV

Table C3 considers the various cost measures for the two models. With efficient curtailment, onshore wind is curtailed to such an extent that it makes little economic sense to expand its capacity, and indeed, the only efficient VRE at the margin is grid-scale PV. The resulting individual cost rankings are PV<OFF<ON for all measures.

Table C3 Cost metrics with efficient curtailment, £(2018)

Spreadsheet model	OFF	ON	PV
LCoE £/MWh	£43.04	£48.20	£40.64
LACoE £/MWh	£44.62	£73.52	£40.64
LMCoE £/MWh	£103.54	£126.58	£66.42
UCED model			
LCoE £/MWh	£43.04	£48.20	£40.64
LACoE £/MWh	£44.55	£72.92	£40.64
LMCoE £/MWh	£92.16	£180.73	£66.42