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Keywords Variable Renewable Electricity, Marginal Curtailment, Average Curtailment, Levelised Cost of Electricity, VRE support design.

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Abstract

High Variable Renewable Electricity (VRE) penetration inevitably causes curtailment (shedding), normally measured by average curtailment. Marginal curtailment (*mc,* the fraction of potential output curtailed by the last MW) can be many times higher, raising the long-run marginal cost of investment, proportional to 1/(1-*mc*). A unit commitment and efficient dispatch model of Britain, divided into seven zones by transmission constraints in 2030, demonstrates that these constraints considerably increase *mc* compared to no congestion despite the considerable expansion of transmission, interconnectors and storage that mitigate curtailment. Current auction design favours levelised costs, ignoring curtailment, but long-run marginal costs may be 90% higher, arguing for careful locational planning.

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1. Introduction

Electricity markets in most countries are facing a rapid increase in Variable Renewable Electricity (VRE, wind and solar PV),[4] both in their quest for decarbonisation and as the cost of VRE has fallen to be competitive with the carbon-adjusted cost of fossil generation. High VRE penetration inevitably leads to curtailment (shedding) as the cost of using surplus energy rapidly rises with volumes. Newbery and Chyong (2025) showed that investing in any single VRE (e.g., onshore wind) would lead to increased curtailment of other VREs (offshore wind, solar PV) as their time pattern of output varies. The effect is to magnify the marginal curtailment (the extra curtailment caused by an extra MW of VRE investment) above the level experienced in countries dominated by a single type (e.g. the island of Ireland with massive onshore wind penetration, Newbery, 2023). This article goes further in demonstrating that VRE investment in zones within a country with limited internal

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[4] Acronyms: a(m)c: average (marginal) curtailment; A(M,P)CF: average (marginal, potential) capacity factor; CfD: Contract for difference; CPI: Consumer Price Index; FES: Future Energy Scenario; HE: Hydrogen Evolution (FES scenario); HPC: Hinkley Point C nuclear power station; L(A,M)CoE: Levelised (average, marginal) cost of electricity; LRMC: long-run marginal cost; *mc* marginal curtailment; NECP: National Energy and Climate Plans; O&M: Operations and Maintenance (costs); RNP:Reformed National Pricing; SEM: Single Electricity Market of the Island of Ireland; SMC: System marginal cost; SNSP: System Non-Synchronous Penetration; TNUoS: Transmission Network Use of System; UCED: unit commitment and economic dispatch; VRE: Variable Renewable Electricity.

transmission capacity has spillover impacts on neighbouring regions, again amplifying marginal curtailment, raising the long-run marginal cost of that VRE.

Most countries have inherited transmission systems designed to deliver power from large fossil and nuclear stations to load centres. VRE is typically located in very different places and is often distant from demand. The result is a rapid increase in congestion at zonal boundaries, demands for new transmission links, and a growing urgency to provide better locational guidance for investment, dispatch, and balancing the system in real time. That was certainly a key motivation of the UK Government's consultation on the *Review of Electricity Market Arrangements* (REMA) in July 2022 (HMG, 2022). Congestion and the need for curtailing VRE is rising rapidly because of the under-appreciated fact that marginal curtailment is 3+ times average curtailment – the statistic that is usually reported. This article provides evidence that marginal curtailment is even more significant where transmission is inadequate for the new spatial patterns of generation investment, hence the urgency of improving locational guidance for that investment and avoiding areas that are already significantly constrained.

Congestion is normally viewed as a problem to be addressed by better siting of new generation, better dispatch of existing generation, and better system planning of transmission. The newly created GB National Energy System Operator (NESO) is charged to engage in Strategic Spatial Energy Planning.[5] All these solutions clearly important, but the contribution of this article is to draw attention to the importance of calculating the marginal, not average or benchmark cost, of new VRE investments in different locations with significant transmission constraints. To be more precise, as shown below, marginal cost increases as $1/(1\text{-}mc)$ where mc is marginal curtailment. Taking this into account would be important even if all location decisions were taken by a NESO, but the aim in liberalised markets is to use price signals to guide location choices and dispatch. What has been missing from policy discussions to date has been the recognition that transmission access and charging arrangements, market and VRE support design all need to give consistent signals sensitive to marginal, not average cost, and these depend on the spatial variation of marginal curtailment – a hitherto neglected area of study.

2. The context: locational investment and dispatch signals

Great Britain, GB, with very few EU countries, already gives strong locational signals through its zonal Transmission Network Use of System (TNUoS) charges, which are set annually and intended to reflect the long-run marginal cost of delivering power from Generators (who face G-TNUoS charges) to Load (who face L-TNUoS charges). The difference between the two delivers the regulated revenue for the Main Interconnected Transmission System. Distant generators face high G-TNUoS charges, and neighbouring Load faces much lower charges (with the difference between the two moderately similar across zones). Some countries charge deep connection charges, reflecting the extra cost the connection imposes on the system, and GB has deep charging for the distribution network. Other EU countries charge low, sometimes zero, generation grid charges and find it hard to

[5] https://www.neso.energy/what-we-do/strategic-planning/strategic-spatial-energy-planning-ssep

encourage efficient investment location, other than those provided by zonal price differences or regional derating factors (Kröger and Newbery, 2024).

Two locational market arrangements can be observed in liberalised electricity markets: Locational Marginal Pricing (LMP), where each node potentially faces a different spot price, and Zonal Pricing (ZP), in which the wholesale price is uniform within defined geographic zones. LMP, a key element in the US Standard Market Design, is found in an increasing share of liberalised electricity markets from Latin America to New Zealand. ZP has been standard in the EU Integrated Market Design since 2014, with some countries having numerous zones (Norway and Italy are leading examples). As congestion rises, some countries (Sweden) or regions (Germany + Austria) have subdivided their original country/region-wide zones to better match emerging congestion boundaries. The European Commission (EC) requires these boundaries to be periodically reviewed and revised if necessary (under Commission Regulation (EU) 2019/943).[6] In particular, ENTSO-E's (2025) latest *Bidding Zone Review* assessed 14 alternative configurations across Central and Nordic Europe, finding no economic efficiency gains in the Nordics but significant benefits, up to €339 million/yr., for splitting the Germany–Luxembourg zone into five. Both Nordic and Central TSOs submitted proposals. The former recommended no change and the latter identified the five-way Germany–Luxembourg split most efficient.

After receiving comments on its first REMA consultation, the UK Government has ruled out LMP, at least for the near future, and in its second consultation, asked for views on and estimates of the benefits of moving to Zonal Pricing (DESNZ, 2024a, b). In July 2025, the Government ruled out ZP and instead opted for Reformed National Pricing (RNP): which "will send a clearer upfront signal ahead of the point of investment decision about the relative system value of investing in different locations, which can be accurately priced into those investment decisions. The new Strategic Spatial Energy Plan (SSEP) aims to foster a coordinated, whole systems approach to planning and to promote anticipatory network investment – reducing waiting times for generation and storage projects to connect to the grid and cutting network constraint costs." (DESNZ, 2025b). RNP does not, however, address the problem of efficient real-time dispatch and interconnector use.

The EU seems likely to retain ZP for most countries, perhaps with increasing granularity, for the same reason as GB, unwilling to disturb current dispatch and concerned about the impact of increased volatility on investment and market liquidity. The impact of ZP on managing high levels of VRE is therefore of general interest, while in GB it can give a measure of the benefits that RNP should attempt to achieve with its various reforms.

One of the main arguments in favour of the higher resolution ZP, rather than the current single GB-wide price, is that it should give better signals for trading over interconnectors, using storage and other demand-side response. Congestion on the increasingly ill-adapted original transmission system will require a massive investment in new links. Still, for the near future (given the time taken to secure permission for new links) and even after they are completed, high ratios of peak to average VRE output (for wind, 2-4:1, for PV in GB 9:1) imply that transmission will limit the amount of VRE that can be transmitted, after which it must be curtailed (constrained-off, spilled or wasted). Scotland,

[6] See https://www.entsoe.eu/network_codes/bzr/

with high wind capacity (relative to its demand), already experiences high wind curtailment rates, shown in Figure 1, and this continues to grow.[7]

Curtailment can be reduced by expanding transmission, exporting and storage. Export and storage demand will depend on the zonal wholesale price and will be limited by local transmission constraints, interconnectors, and storage capacity. If North Britain's wind is curtailed, the zonal price should be near zero, signalling exports to Norway (over the North Sea Link). However, a single GB-wide price may be quite high, encouraging imports from Norway. Similarly, injections into storage (batteries and pumped storage) may be encouraged with zonal surplus VRE but discouraged with GB-wide prices, at least without sophisticated options in the new RNP.

Different types of VRE have different output profiles (PV peaking at mid-day, onshore wind experiencing patterns driven by daily temperature differences between land and sea, while offshore has more consistent hourly patterns). The key finding of Newbery and Chyong (2025) was that increasing any single technology impacts curtailment of all VRE, but to different extents. These complex interactions amplify marginal curtailment. While marginal/average curtailment ratios might be 3-4 in areas dominated by a single type of VRE (e.g. onshore wind on the island of Ireland, Newbery, 2021), the ratio increases considerably with multiple types of VRE, for good theoretical reasons set out in Newbery (2025). This article shows that the complexity of VRE interactions and their cost implications in different locations increase considerably once transmission constraints become significant.

This article explores the impact of moving from the current GB system, in which curtailment is ignored in determining payments to (contracted) VRE, to one in which GB is divided into seven zones[8] defined by major boundary transmission constraints, and VRE contracts are modified to make VRE market responsive (as required by EU Regulation 2024/1747; EU, 2024). Its central concerns are:

1. to estimate the additional curtailment resulting from recognising internal transmission constraints compared to those assuming the GB is a "copper plate" with no internal constraints, but only export limits,
2. to measure marginal and average curtailments (*mc, ac*) with and without internal constraints,
3. to explore how cross-boundary flows of surplus VRE impact curtailment in different zones, and
4. to measure the appropriate long-run average and marginal costs of investing in different VRE in each zone.

3. Measuring constraints and costs

Curtailment is normally measured by the fraction of potential output curtailed, as in Figure 1, which is the convention followed here. Thus, in 2021, curtailment is shown as roughly 13% of the potential output. Marginal curtailment is similarly measured relative to potential output. In 2023-24, the UK-wide total (on- and offshore) average curtailment (*ac*) rose from

[7] https://ukerc.ac.uk/news/transmission-network-unavailability-the-quiet-driving-force-behind-rising-curtailment-costs-in-great-britain/

[8] FTI's Report to Ofgem studied a seven-zone model of GB but with slight differences in the zonal boundaries in SE England (FTI, 2023) to those in Figure 2.

5% to 9%.[9] If the UK replicated curtailment in the SEM, the marginal curtailment rate, *mc*, would be 15-27% or more. One offshore wind farm (Seagreen) was curtailed 71% in 2024, despite receiving payments for its potential output,[10] illustrating the potentially high ratio of *mc/ac*.

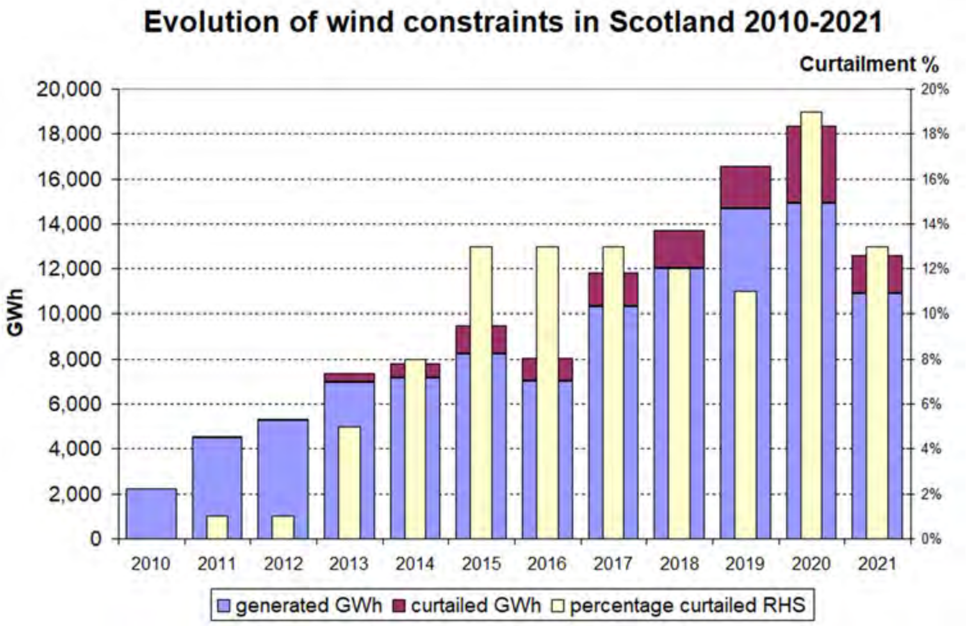

Figure 1: Curtailment of Scottish onshore wind farms 2010-21
Source: Renewable Energy Foundation at https://www.ref.org.uk/ref-blog/371-constraint-payments-to-wind-power-in-2020-and-2021
Notes: RHS = Right hand side (axis): shows curtailment as a percentage of potential output

The standard measure of the cost of investing in additional VRE is the levelised cost of electricity, LCoE, where LCoE = $F/(8760*\text{PCF}) + v$. F is the annualised fixed cost per MW of capacity (capital cost annuitized over its life and any annual fixed costs, e.g., O&M, rent, insurance, grid charges, etc. as explained in BEIS, 2023), v is the variable operating cost, £/MWh and PCF is the Potential Capacity Factor, measured as a percentage (thus 8760*PCF is the equivalent full operating hours per year). The long-run average and marginal levelised costs are similarly $F/(8760*\text{ACF})+v$ and $F/(8760*\text{MCF})+v$, where ACF is the average capacity factor and MCF the marginal capacity factor, both as percentages. These, in turn, are reduced by curtailment to

$$\text{ACF} = \text{PCF}-ac*\text{PCF} = (1 - ac)*\text{PCF}; \tag{1}$$

$$\text{MCF} = (1 - mc)*\text{PCF}. \tag{2}$$

The average cost is measured by the levelised average cost LACoE:

$$\text{LACoE} = (\text{LCoE} – v)/(1 - ac) + v. \tag{3}$$

[9] https://www.ref.org.uk/ref-blog/384-discarded-wind-energy-increases-by-91-in-2024
[10] https://www.ref.org.uk/ref-blog/384-discarded-wind-energy-increases-by-91-in-2024

If the variable operating cost is zero or near zero, then the levelised average cost is just LCoE/(1 - ac), and the factor PCF/ACF = 1/(1 - ac) is a convenient summary measure. The levelised marginal cost is

$$\text{LMCoE} = (\text{LCoE} - v)/(1 - mc) + v, \tag{4}$$

which again is approximately LCoE /(1 - mc), with PCF/MCF = 1/(1 - mc) the relevant summary measure. Thus, if ac = 11% (2024 values),[11] and if mc were as low as 3*11%, the LMCoE/LCoE would be 1/(1 - 0.33) = 1.5. The ten most curtailed windfarms, accounting for 9.5% of total potential output, were all curtailed more than 40% of the time. The claim of this article is that more attention should be paid to the long-run marginal cost when procuring investment, and hence to the MCF and mc. Newbery and Chyong (2025) provide a useful figure illustrating the relation between the various concepts.

4. Literature review

Integrating high shares of variable renewable energy (VRE) into electricity systems has directed attention to the limitations of existing market designs, notably their failure to provide good spatial price signals and locational guidance for new generation. A particular blind spot in policy and academic work is the distinction between average curtailment – typically reported by system planners and modellers – and marginal curtailment, which determines the economic viability of adding renewables in constrained locations.

Newbery (2021) analysed wind curtailment in the Single Electricity Market (SEM) on the island of Ireland under frequency stability constraints, while ignoring internal transmission bottlenecks. Newbery and Biggar (2024) studied a Renewable Energy Zone in Queensland, Australia. They provided a geometric demonstration that marginal curtailment (mc) can far exceed average curtailment (ac) when transmission export limits bind. Newbery and Chyong (2025) extended this analysis to consider multiple VRE by simulating the GB 2030 *Hydrogen Evolution Future Energy Scenario* (ESO, 2024). They assumed a copper-plate (uniform national pricing) and found mc/ac ratios of 5–7, modelling export interconnector constraints but not internal transmission limits.

A growing empirical and modelling literature has examined the role of spatial price granularity – zonal or nodal pricing – in improving operational efficiency and guiding efficient investment. It concludes that while spatial pricing improves redispatch and cost outcomes, the effect on investment risk, liquidity and curtailment, particularly marginal curtailment, remains understudied and poorly understood.

Several studies investigate actual transitions from zonal to nodal pricing. In the ERCOT market, Zarnikau et al. (2014) found that nodal pricing led to a 2–3% reduction in average wholesale prices for load-serving entities. Triolo and Wolak (2022) estimated a 3.9% drop in thermal generation costs, or over $300 million in annual savings. In California, Wolak (2011) showed that gas-fired plants reduced energy consumption by 2.5% after the switch to nodal pricing. These studies highlight improved dispatch efficiency and reduced reliance on redispatch.

Other work evaluates the limits of zonal pricing reform in Europe. Using ENTSO-E's *Bidding Zone Review* (BZR) data, Bichler et al. (2025) simulate various 2025 zonal

[11] Both taken from https://windtable.co.uk/ and taken from balancing mechanism reports

configurations in Germany and found only marginal gains in system cost and price differentiation. Dobos et al. (2025) assessed the stability and coherence of zones proposed by ACER and concluded that they offer a slight improvement in price signals or congestion management, but they are unstable over time. Loiacono et al. (2025) examined Sweden's earlier market split and found that while price signals improved in the south, the reform had modest effects on overall efficiency. These results are unsurprising as the main gains are likely reaped in the first move from national to internal zonal pricing. The gains should increase as internal congestion rises with increasing VRE penetration.

A third group of studies examines how spatial pricing might affect long-term investment decisions and curtailment. Ambrosius et al. (2020) developed a multilevel optimisation model of the German market. They showed that optimally defined price zones significantly reduced RES curtailment and shifted investment toward cleaner, more efficient technologies. Katzen and Leslie (2024) offer direct empirical evidence that Australia's zonal market led to inefficient siting of wind and solar behind constraints, resulting in 4.4% and 4.7% curtailment, respectively – levels that would likely be reduced under a nodal design. Lundin (2022) found that Sweden's zonal reform caused large developers to shift 18% of wind projects to higher-priced zones, demonstrating a measurable investment response.

Several studies assess how spatial pricing interacts with demand-side flexibility. Boehnke et al. (2025) evaluate over 3,600 nodes across Europe and show that nodal pricing reveals localised "flexibility hot spots" where distributed storage, EVs, and heat pumps provide much higher value than under zonal pricing. Lyden et al. (2024) explore a similar question for the UK, finding that locational pricing increases the operational cost of heat pumps in some regions while lowering it in others, thereby influencing the spatial rollout of electrified heat. Kenis et al. (2024) extend this demand-side flexibility insight to hybrid offshore wind, showing that full nodal pricing achieves the lowest curtailment and highest welfare when integrating co-located electrolyser demand. These findings indicate that spatial granularity is not only crucial for generation but also for unlocking demand-side resources that mitigate curtailment.

Many studies suggest that the welfare benefits of granular pricing can be significant. Green (2007) estimated that nodal pricing in a stylised GB model improved welfare by 1.3% of generator revenues. Neuhoff et al. (2013) simulated the EU grid and found that nodal pricing increased cross-border flows by 34% and reduced operating costs by up to €2 billion annually (1.1%-3.6% of total operating costs). Aravena and Papavasiliou (2016) compared nodal and zonal coordination mechanisms and concluded that zonal designs led to higher balancing and redispatch costs than nodal pricing, especially under forecast errors – a known driver of VRE curtailment.

Savelli et al. (2022) modelled GB's transmission network. They quantified how incremental wind capacity caused considerable regional variation in system-wide costs: each additional MWh of wind in the north added £5.61/MWh in congestion cost, and redispatch increased CO_2 emissions. Southern deployment reduces congestion and emissions. Although the study does not compute marginal curtailment, it demonstrates that incremental renewable generation has sharply location-dependent system effects, reinforcing our central claim.

Finally, a subset of studies highlights the institutional and political challenges of spatial pricing reform. Lindberg (2022) compared the Nordic and German markets and found that stakeholder coalitions strongly influenced market design persistence. Eicke and Schittekatte (2022) systematically debunk common arguments against nodal pricing in Europe, concluding that most concerns (e.g. market power, flexibility, liquidity, investment risk, complexity, and locational price differences) are overstated or can be mitigated. Dobos et al. (2025) show that even when data-driven zone configurations are proposed, they are often unstable, politically contested, and misaligned with actual system constraints.

To summarise, these academic studies offer consistent evidence that spatial price granularity improves operational efficiency, investment decisions, and lowers overall system cost. Increased price volatility brings risks that could offset these cost reductions if not mitigated. Many simulate reduced redispatch volumes and price disparities, and some document lower curtailment under optimised zonal or nodal pricing. Yet a critical gap remains across the academic literature: no study systematically evaluates *marginal* curtailment rates in a spatially granular pricing regime considering network constraints.

A parallel body of consulting studies – commissioned to inform the GB *Review of Electricity Market Arrangements* (REMA) – provides valuable system-specific insight on the potential impacts of spatial pricing reform. Studies by FTI Consulting (2023, 2025), AFRY (2025a, b), Aurora (2023), Frontier Economics & LCP Delta (2024), and LCP Delta (2024) model various zonal and national pricing scenarios, primarily using dispatch and investment models calibrated to GB's network and capacity plans. There is a broad consensus across these studies that locational pricing improves dispatch efficiency and reduces constraint costs, particularly in scenarios with high levels of VRE and network congestion. However, significant divergences emerge in the scale and robustness of these benefits. For instance, FTI (2025) estimates up to £54.9 billion in consumer benefit under a nodal market (discounting over 2030-2050, although only £25 billion in social welfare as producers lose). AFRY (2025b) shows that more realistic assumptions about wind siting, interconnector viability, and coordinated network reinforcement reduce this to £8.9 billion – and potentially eliminate benefits if capital costs rise or cross-border wealth transfers are offset through compensation. Aurora (2023) and AFRY (2025a) argue that enhanced redispatch, balancing reform, and interconnector coordination within a national market design could deliver comparable efficiency gains with lower implementation risk. In contrast, FTI (2025) frames zonal pricing as a safeguard if centralised planning falls short of timely delivery.

A key area of agreement is that zonal pricing alone cannot deliver efficient investment outcomes unless paired with reforms to support schemes (notably Contracts for Difference) and transmission charges. Several studies acknowledge that generators in low-price, high-curtailment zones would likely require higher strike prices to remain viable, reducing headline consumer benefits.

Yet despite extensive modelling, all these consulting studies share a critical limitation: none quantify marginal curtailment – the increase in curtailment experienced by each additional unit of VRE capacity in a constrained zone. While several studies report average curtailment rates or aggregate constraint costs, they do not estimate the marginal impacts that shape the long-run marginal cost of VRE deployment. Nor do they explicitly link curtailment dynamics to zone-specific investment signals or support scheme design. As such, they provide limited insight into how spatial pricing reform might reshape the economic viability of incremental VRE additions across GB.

Most electricity system optimisation (production cost) models used for long-term planning adopt a least-cost optimisation framework that identifies capacity portfolios and dispatch outcomes. Oree et al. (2017), Koltsaklis and Dagoumas (2018), Dagoumas and Koltsaklis (2019), and van Ouwerkerk et al. (2022) provide reviews of such modelling frameworks. However, the models do not explicitly compute marginal curtailment or reveal the long-run marginal cost of expanding specific technologies in specific locations. While such models are useful for system planning, they often remain opaque to market designers and policymakers, who require marginal metrics to design effective procurement and deployment strategies for renewable investment. This further underscores the need for an analytical framework that explicitly measures long-run marginal costs (LRMCs) in different locations in a constrained network.

This article addresses that gap by deploying a Unit Commitment Economic Dispatch (UCED) model of the GB power system to compute average and marginal curtailment rates under national and zonal pricing regimes. From this, it derives zone-specific LRMCs for wind and solar, accounting for both curtailment and locational differences in output. The resulting analysis provides a novel basis for evaluating support scheme redesign, locational investment risk, and the role of transmission charging in a future spatially granular market design.

5. Methods

For this analysis, we used the UCED model of the GB power system, an extension of the framework developed by Chyong and Newbery (2022). The model covers 19 European national electricity markets (Appendix A, Table A.1), divided into 28 zones to capture key transmission constraints explicitly. Great Britain, GB, is represented as seven zones (Z1–Z7), separated by transfer-constrained internal boundaries (Figure 2). Table 1 reports the directional transfer capacities in 2023 and 2030 for GB and the associated export capacities to neighbouring systems. These internal limits bind zonal flows (e.g. B4, B6, B7a, B8, EC5, SC1), while export capacities represent the aggregated ability of a zone to trade abroad (e.g. SEM, NO, BE, DE, DK, NL, FR). Demand and VRE assumptions are based on ESO's (2024) *Hydrogen Evolution* scenario, which projects cautious growth in VRE capacity to 2030 alongside significant gas-fired generation. ESO (2024) also provides assumed 2030 VRE capacities for European countries. Zonal hourly VRE profiles are constructed from 1998 output data, preserving the underlying hourly patterns for consistency across VRE generation (domestic and foreign) and demand. Full details are provided in Appendix A.

Figure 2 Zonal boundaries selected for zonal pricing experiments

Table 1: Transfer capacity (MW) in 2023 and 2030, and 2030 export capacity (MW)

From	To	Boundary	2023 cap.	2030 cap.	External	To
Z1	**Z2**	B4	4,000	7,300	0	
Z2	**Z3**	B6	6,700	10,200	450	SEM
Z3	**Z4**	B7a	9,400	13,500	1,464	NO
Z4	**Z5**	B8	11,000	16,400	500	SEM
Z5	**Z6**	EC5	3,300	13,500	7,100	BE,DE, DK,NL,SEM,FR
Z5	**Z7**	SC1	3,900	6,100	5,000	BE,FR

Source: ESO (2024) and Appendix A

5.1 Data and temporal resolution

The dataset (Appendix A) includes zonal capacities of VRE and dispatchables, storage options, internal transfer constraints (Table 1), external interconnectors, and hourly zonal demand and VRE output profiles. Simulations run at hourly resolution, balancing supply and demand in each zone.

5.2 Operational and security constraints

- System stability: system-wide VRE is capped at 90% of demand plus exports and storage injections to maintain frequency stability (Appendix A).
- Must-run plants: nuclear and waste-to-energy are treated as must-run; VRE is curtailed before these are ramped down. In the base case, must-run plants alone provide insufficient inertia for 1,339 hours, requiring curtailment; transmission/export limits add a further 441 curtailed hours.
- Losses and curtailment ordering: The System Operator currently charges average transmission losses via seasonal loss factors[12] (–4% to +3% in winter 2022–23,

[12] https://www.neso.energy/document/352996/download

average 0.5%[13]). Actual marginal losses are about twice this ($L=I^2R$,[14] $dL/dI=2IR$), so distant generators are undercharged. The model simplifies loss modelling by applying zonal Transmission Marginal Cost (TMC) adders (Z1: €0.5/MWh, declining to €0 in Z5, €0.1 in Z6–Z7) to penalise more distant VRE when curtailment is required. As each VRE type has the same avoidable cost, without TMC charges curtailment choices become arbitrary and unstable. These adders are irrelevant under the copper plate solution but significant when zonal boundaries bind.

5.3 Model solution

For each hour, the model solves for zonal System Marginal Costs (SMC), trades across internal and external boundaries, storage schedules, and VRE curtailment, subject to stability and transmission/export limits. Outputs relevant for this paper include:

- Curtailment volumes and rates (average curtailment, *ac* = curtailed/potential output).
- Marginal curtailment (*mc* = Δcurtailment/Δpotential output).
- Trade differences relative to copper plate (mean and standard deviation of hourly export differences).
- Cost multipliers (1/(1–*mc*)) used in later LMCoE calculations.

5.3.1 Scenario design

The analysis in Section 6 is structured around a series of cases, each modifying the baseline assumptions in a controlled way. These are summarised in Table 2, which sets out the main features of each case and the key output metrics.

Table 2: Case design and model output metrics

Experiment	Constraints	VRE capacity change	External assumption	Nuclear assumption	Output metrics
Baseline vs copper plate	2030 transfer limits (zonal) vs none (copper plate)	None	FES HE	HPC1&2 + SZB online	Curtailment volumes/rates by zone & tech; hours curtailed; trade vs copper plate
Boundary reinforcement	Compare 2023 vs 2030 transfer limits	None	FES HE	HPC1&2 + SZB online	Curtailment differences by zone & tech; total reduction
Targeted increment Z4 onshore wind	2030 transfer limits	+3% Onshore wind in Z4 (+159 GWh)	FES HE	HPC1&2 + SZB online	Δcurtailment by zone & tech; *mc* for increment
Zone-by-zone VRE increments	2030 transfer limits	One-zone increment at a time (+200 MWh/h GB avg by tech)	FES HE	HPC1&2 + SZB online	Δcurtailment, *mc*, *ac*, and *PCF/MCF* multipliers 1/(1–*mc*)
Sensitivity 1: Nuclear delay	2030 transfer limits	None	FES HE	HPC1 only (vs HPC1&2)	Δcurtailment; emissions reduction
Sensitivity 2: High EU VRE	2030 transfer limits	None	Higher EU VRE penetration (NECP)	HPC1&2 + SZB online	Curtailment by zone; % increase; change in GB net exports

[13] https://www.elexonportal.co.uk

[14] where *I* is the current and *R* is the resistance of the connection from injection to load

6. Results

The results are presented for the series of cases defined in Table 2. Each case modifies the baseline 2030 FES HE assumptions in a controlled way in order to test how internal boundary limits, capacity expansions, and external factors affect curtailment and costs. We begin by comparing the baseline zonal outcomes with a copper plate benchmark, then examine the effect of expanding internal transmission capacities, before turning to targeted and proportional VRE expansions, zone-by-zone increments, and sensitivity cases covering nuclear commissioning and higher EU VRE penetration.

6.1. Baseline vs copper plate

Table 3 compares the baseline 2030 FES HE with internal constraints to the copper plate case (Newbery and Chyong, 2025; HPC1&2 and SZB operating). With zonal constraints, total VRE curtailment is 10,426 GWh, 19% higher than under copper plate (8,771 GWh). Curtailment is highly concentrated: Z1 and Z2 together contribute 86% of the total. Z1 is curtailed 1,852 hours, and Z2 is curtailed 948 hours. Z1 is always curtailed when Z2 is curtailed, underscoring the dominance of the B6 boundary at the Scottish border (Figure 2).

Technology shares differ across zones – Z4 and Z6 have the highest shares of offshore wind, Z5 and Z7 of PV, and Z1 and Z2 of onshore wind – so pro-rata curtailment at the zonal level amplifies technology-specific effects relative to national pro-rata curtailment.

External trade impacts are modest: the average absolute hourly difference in exports between zonal pricing and copper plate is 37 MW (standard deviation 166 MW), and total GB external exports fall by about 1%. Exports do little to relieve internal constraints because Z1 and Z2 can export only modest volumes to the SEM, and the Norway link is in Z3.

Table 3 Zonal results in 2030 *FES HE*

Baseline		Z1	Z2	Z3	Z4	Z5	Z6	Z7	Total	Copper Plate
Capacity MW	OFF	4,356	3,516	2,890	11,785	5,824	11,708	3,399	43,476	43,476
	ON	6,930	9,672	908	2,071	2,698	271	530	23,081	23,081
	PV	743	628	1,530	3,730	14,598	1,098	5,318	27,644	27,644
	VRE	12,028	13,817	5,328	17,586	23,119	13,076	9,246	94,201	94,201
Transmission marginal costs €/MWh	TMC	€ 0.50	€ 0.40	€ 0.30	€ 0.20	€ 0.00	€ 0.10	€ 0.10		
potential output GWh	OFF	18,785	15,202	13,034	55,148	27,582	54,483	14,619	198,854	198,854
	ON	16,996	23,653	2,285	5,159	6,865	687	1,291	56,935	56,935
	PV	575	511	1,378	3,234	13,827	1,108	5,565	26,199	26,199
	VRE	36,356	39,366	16,698	63,540	48,274	56,278	21,475	281,988	281,988
curtailment GWh	OFF	2,559	1,264	190	456	306	56	80	4,910	6,075
	ON	2,784	2,308	39	50	90	1	8	5,280	2,088
	PV	43	33	16	22	102	1	20	236	608
	VRE	5,386	3,604	245	527	497	58	108	10,426	8,771
ac p.c. potential output	OFF	13.6%	8.3%	1.5%	0.8%	1.1%	0.1%	0.5%	2.5%	1.6%
	ON	16.4%	9.8%	1.7%	1.0%	1.3%	0.1%	0.7%	9.3%	1.0%
	PV	7.5%	6.4%	`	0.7%	0.7%	0.1%	0.4%	0.9%	0.3%
	VRE	14.8%	9.2%	1.5%	0.8%	1.0%	0.1%	0.5%	3.7%	1.1%
zonal av. trade	MW	3,016	2,394	498	3,195	-15,721	6,823	-205		

Copper plate results from Newbery and Chyong (2025), HPC1&2 and SZB operating. OFF: offshore wind, ON: onshore wind.

6.2. Contribution of expanding internal boundary capacities

Holding 2030 VRE capacities fixed, Table 4 compares curtailment under 2023 versus 2030 internal boundary transfer capacities. Curtailment falls from 46,326 GWh (2023) to 10,426 GWh (2030), a 77% reduction (more than the 59% reduction under copper plate). The main beneficiary is Z6, where a quadrupling of export capacity to Z5 almost eliminates previously very high curtailment. Z1 and Z2 also benefit substantially. One consequence is that Z3–Z5 experience higher curtailment as inflows from Z1, Z2 and Z6 increase.

Table 4: VRE Curtailment of VRE: 2030 vs 2023Transmission Capacity

		Z1	Z2	Z3	Z4	Z5	Z6	Z7	Total	Copper Plate
2030 Transmission Capacity	GWh	5,386	3,604	245	527	497	58	108	10,426	8,771
2023 Transmission Capacity	GWh	9,720	4,910	162	280	226	30,975	54	46,326	21,338
difference	GWh	4,334	1,306	-83	-247	-272	30,917	-54	35,900	12,567

Notes: as for Table 3.

6.3. VRE Capacity expansions and marginal curtailment

The next set of experiments is to expand capacity of specific VREs one zone at a time, to identify their marginal curtailment, the key element in determining long-run marginal cost. Investment in one zone has impacts on neighbouring zones, which are illustrated in the next section.

6.3.1. Targeted expansion in Z4

Increasing onshore wind in Z4 by 3% (+159 GWh potential) raises curtailment by 39 GWh across all VRE and zones, i.e. *mc* = 24% (39/159) of the potential output. Average curtailment from Table 3 is ~1%, so *mc/ac* = 24, illustrating that *mc/ac* is not informative at low *ac*. Most additional curtailment occurs in Z4, but Z1 and Z2 also rise, while Z5 falls because Z4 has slightly higher assumed variable costs and transmission charges (Table 3), and is preferentially curtailed. With higher variable costs and fewer export options, Scotland is more severely curtailed as it experiences more hours of near saturation.

Table 5 Impact on total curtailment by zone of expanding onshore wind in Z4

Expand Z4 ON		Z1	Z2	Z3	Z4	Z5	Z6	Z7	Total
Δ curtailment GWh	OFF	4.4	4.1	0.9	14.3	-0.7	-0.2	0.2	23
	ON	7.0	6.2	0.2	1.6	-0.3	0.0	0.0	15
	PV	0.3	0.3	0.2	0.7	-0.4	0.0	0.0	1
	VRE	11.7	10.6	1.2	16.5	-1.4	-0.2	0.3	39
Δ pot. output GWh	ON				159				
mc p.c. of pot. output	ON				24%				

Table 5 shows the zonal detail of the way in which investing in one zone impacts neighbouring zones, but the key metric is the *mc* associated with that zonal investment. The next section summarises such impacts but just in terms of marginal curtailments.

6.3.2. Impact of zone-by-zone VRE capacity expansion

Table 6 shows the result of increasing each VRE by the same proportion of zonal installed capacity one zone at a time, replicating Table 5. (Appendix B, Table B1 shows the full impact by zones of each increment.) Thus if offshore wind is increased in Z1 to give a potential increase in output of 166 GWh in Z1 (delta potential output), it would cause an extra 57 GWh VRE curtailment (compared to the baseline), giving *mc* = 34% of the potential output (57/166). From Table 2 *mc/ac* = 2.5, lower as *ac* is so high. Note that the results for on-shore wind in Z4 is the same as Table 5. The ratio PCF/MCF = 1/(1-*mc*) = 1.52 is shown in the lower part of the table. The highest values of *mc* arise in Z1 and Z2, again showing the importance of the B6 boundary. The PCF/MCF ratio for on and offshore wind assumes the same 2030 capacity factors in each zone as in each zone the spatial variation in wind strength is quite high so the assumption is that developers will choose the best zonal sites. This may be optimistic and lower PCFs will lead to higher costs. For solar PV the variation in PCF from South to North is too large to ignore, and so local average values are used, giving rise to the PCF/MCF ratios shown in the last line.

Table 6: Marginal contributions of additional VRE capacity zone by zone

		Z1	Z2	Z3	Z4	Z5	Z6	Z7	total
delta potential output, GWh	OFF	166	134	115	486	243	480	129	1753
	ON	523	728	70	159	211	21	40	1752
	PV	38	34	92	216	922	74	371	1747
delta curtailment GWh	OFF	57	48	20	84	39	80	22	350
	ON	249	339	15	39	48	0	6	694
	PV	10	9	11	22	115	13	38	218
mc p.c. of potential output	OFF	34%	36%	17%	17%	16%	17%	17%	20%
	ON	48%	47%	21%	24%	23%	0%	14%	40%
	PV	26%	26%	12%	10%	12%	17%	10%	12%
ac p.c. pot. output	PV	8.9%	9.3%	10.3%	9.9%	10.8%	11.5%	12.0%	11%
1/(1-*mc*)	OFF	1.52	1.56	1.21	1.21	1.19	1.20	1.20	1.25
	ON	1.91	1.87	1.27	1.32	1.29	1.00	1.16	1.66
	(PV)	1.35	1.36	1.14	1.11	1.14	1.21	1.11	1.14
scaled for PV CF*	PV	1.67	1.61	1.22	1.24	1.16	1.15	1.03	1.14

Notes: As for Tables 3 and 4

* Scaled for the average PV zonal capacity factors to give the relevant PCF/MCF.

Table 6 shows that any additional VRE investments in Scotland (Z1 + Z2) would be heavily curtailed, greatly increasing their marginal cost, even if some locations there have higher than average PCFs. Onshore wind in Z6 can be further expanded at no extra cost, but apart from that most VREs in Z3-7 experience similar marginal curtailment, suggesting that pursuing high PCF locations need not pay much attention to zonal boundaries.

6.3.4. Impact of nuclear generation

Just as expanding a single VRE technology increases curtailment of other VREs, so expanding nuclear power is expected to increase VRE curtailment, but with an important mitigating factor. Nuclear power has lower avoidable costs (negative) than VRE so will preferentially displace VRE, but also contributes essential inertia that accommodates more VRE. In the base case, in 75% of the hours of curtailment, nuclear power was insufficient to provide sufficient inertia to absorb VRE, even with our optimistic assumptions on commissioning both Hinkley Point C turbines by 2030. Table 7 examines the consequences of only commissioning HPC-1 (described as a delay).

Table 7: Curtailment from expanding nuclear power

		Z1-Z5	Z6	Z7	Total
capacity MW	HPC	0	1,198	3,372	4,570
	delay	0	1,198	1,702	2,900
nuclear output GWh	HPC	0	8,267	23,269	31,536
	delay	0	8,267	11,745	20,012
curtailment GWh	HPC	10,260	58	108	10,426
	delay	9,094	54	101	9,249
delta output GWh		0	0	11,524	
delta curtail GWh					1,177
Emissions reduction p.c. actual output					10.2%

Note: delay means HPC-2 not available

The table implies that the result of commissioning HPC 2 is to increase VRE curtailment by 1,177 GWh, reducing zero-carbon emissions by 10.2% of the potential nuclear output. Nuclear's emission reduction is considerably below that of expanding offshore wind in any zone separately (Table 6, where *mc* varies from 16% to 36%), considerably better than most onshore wind locations, which can be as high 48% with the notable exception of Z6, and comparable to southerly PV (Z5-7).

6.3.5 Higher EU VRE penetration

Europe's most recent *National Energy and Climate Plans* (NECP) show significantly higher shares of wind and solar than those in the FES HE scenario assumed so far, as illustrated in Newbery and Chyong (2025, Fig. 6). This will clearly impact GB's ability to export surplus VRE, as Table 8 shows. The same increase is found when looking at individual expansions in specific zones. Appendix B, Table B2 shows high EU VRE increases marginal curtailment in Z5 by between 44% (ON) and 72% (OFF).

Table 8: Impact of higher EU VRE penetration

Sensitivity to higher EU VRE		Z1	Z2	Z3	Z4	Z5	Z6	Z7	Total	Copper Plate
high EU VRE curtailment GWh	VRE	7,365	6,491	527	1,061	1,106	122	233	16,904	14,727
base curtailment GWh	VRE	5,386	3,604	245	527	497	58	108	10,426	8,771
Increase GWh	VRE	1,980	2,887	281	534	609	64	124	6,478	5,956
p.c. increase		37%	80%	115%	101%	122%	111%	114%	62%	68%

Source: Table 3, and Newbery and Chyong (2025, Table 5)

Net exports fall from 35 TWh to 18 TWh, and total curtailment increases by 62% (slightly less than assuming a copper plate, but still absolutely higher). The main impacts are on the well-interconnected central and southern zone, while the impact is lower on poorly interconnected Scotland (Z1 + Z2). Clearly, Britain's ability to export surplus VRE is likely to be increasingly constrained as the Continent expands its VRE.

7. Cost Implications

The long-run marginal cost of expanding VRE will be a mark-up of the levelised cost of electricity, LCoE. BEIS (2023) provides forecasts (at £2021) for VRE commissioned in 2030 that reflect the very considerable improvement in capacity factors. Table 9 shows the zonal TNUoS charge adjustments to add to the BEIS data and the raw data for LCoEs in the bottom panel, ignoring these adjustments.

Table 9: Levelised costs for 2030 £(2024)/MWh

Zone	OFF	ON	PV	PV mid-scale
Z1	£16.83	£14.27	£12.02	£12.02
Z2	£7.51	£5.76	£4.21	£4.21
Z3	-£3.57	-£3.29	-£3.04	-£3.04
Z4	-£9.72	-£8.10	-£6.66	-£6.66
Z5	-£14.92	-£12.61	-£10.58	-£10.58
Z6	-£8.05	-£7.15	-£6.35	-£6.35
Z7	-£11.91	-£9.34	-£7.06	-£7.06
LCoE	£46.44	£42.87	£44.06	£86.93
variable cost *v*	£1.19	£7.15	£0.00	£0.00
LCoE-*v*	£45.25	£35.73	£44.06	£86.93

Source: BEIS (2025), uprated to £2024 with the CPI, Appendix A

Combining the results of Table 6 and Table 9 gives the long-run average and marginal costs of investment (i.e. the LACoE and LMCoEs). Table 10 shows the results of applying equation (4) to the factors $1/(1 - mc)$ in Table 6 and adjusting for variable costs, demonstrating the considerable cost disadvantage of locating additional VRE in Z1 & Z2.

Table 10: Levelised marginal costs of VRE £2024/MWh

	Z1	Z2	Z3	Z4	Z5	Z6	Z7
OFF	£95.36	£83.64	£51.48	£44.16	£37.39	£45.87	£41.32
ON	£102.46	£84.74	£48.29	£43.67	£37.02	£35.73	£37.89
PV grid-scale	£93.87	£77.52	£50.05	£46.29	£38.91	£43.40	£37.97
PV mid-scale	£165.62	£146.37	£102.36	£99.35	£88.73	£92.74	£81.97

Source: Table 9 with zonal TNUoS charges *less* the average TNUoS assumed in Table 9

Table 11 repeats the exercise but uses the average curtailments from Table 3. For comparison, the next nuclear power station has a CfD strike price of £$_{2012}$89.50/MWh or, uprating to 2024 prices, an LCoE of £$_{2024}$123.90/MWh. Its LMCoE would be £137.60/MWh less a TNUoS credit of £0.60/MWh,[15] or £137/MWh. Currently, VRE in most zones is cheaper, but this ignores additional system costs, such as the extra cost of transmission needed to deliver the planned VRE expansion and other additional ancillary costs.

Table 11: Levelised average cost of VRE £2024/MWh

	Z1	Z2	Z3	Z4	Z5	Z6	Z7
OFF	£73.06	£58.73	£43.49	£37.02	£31.86	£38.43	£34.71
ON	£66.94	£53.13	£40.16	£35.05	£30.58	£35.76	£33.71
PV grid-scale	£75.36	£61.09	£44.41	£41.84	£34.32	£36.01	£34.18
PV mid-scale	£132.97	£115.35	£90.82	£89.79	£78.27	£76.95	£73.78

Source: Table 3 with zonal TNUoS charges, *less* average TNUoS assumed in Table 10

The UK Government publishes LCoEs for the range of currently plausible generation technologies, which are used to guide expectations in capacity auctions and VRE CfD

[15] 2024-25 G-TNUoS in Somerset and Wessex. This is based on the zone currently importing, but when HPC is commissioned it qill become an export zone with a probably higher TNUoS charge.

auctions. At present, grid-connected and offshore wind farms are offered firm access, meaning they will be compensated for their lost profit if they are constrained off. As such, they will be guided by the LCoEs when bidding in the annual CfD auctions. The European Union now requires that CfD holders "should participate efficiently in the electricity markets" (EC Regulation 2024/1747, §41). One way this could be encouraged is instead of offering CfDs that pay on offered, not metered amounts, to replicate the standard two-way CfD that pays on a pre-determined volume regardless of actual output. To preserve hedging, this volume could be the day-ahead (or intraday) forecast of VRE output.

If this were combined with the EU model of not paying when wholesale prices fall to zero, the relevant cost measure would be the LACoE. If, in addition, the fixed tenor CfD were replaced with a fixed hours CfD (e.g. 40,000 MWh/MW, Newbery, 2023), bidders would expect to recover their full (undiscounted) costs over the contract period, and somewhere between the LCoE and the LACoE would represent the relevant cost metric. Finally, in judging where to offer VRE connection, NESO might better be guided by the LMCoE, and as a result, massively discourage any VRE connecting in Zones 1 and 2.

The analysis above just looks at the investment costs of VRE, ignoring system integration costs (transmission, although connection charges are included) and other ancillary services, which should ideally be reflected in market prices. In addition, high levels of VRE will impact wholesale prices inversely to supply. This is typically accounted for through the capture factor (output-weighted/time-weighted wholesale prices). The UCED model only measures the system marginal cost (SMC), ignoring necessary mark-ups likely applied in low VRE hours to recover full operating costs. The resulting capture factors based on SMCs are shown in Table 12.

Table 12: Capture factors relative to zonal SMCs

	Z1	Z2	Z3	Z4	Z5	Z6	Z7
OFF	78%	88%	83%	83%	83%	83%	84%
ON	93%	78%	85%	85%	84%	85%	85%
PV	95%	96%	92%	93%	90%	91%	92%

Note: Defined as output-weighted system marginal cost(SMC) /zonal time-weighted SMC

The higher capture factors in Z1 and Z2 reflect the lower average zonal SMCs, driven by high levels of VRE. If, instead, the capture factors are related to the average time-weighted price across all zones, the results look less surprising and are shown in Table 13. Note that these are based on average capacity factors, not potential or marginal capacity factors.

Table 13: Capture factors relative to GB average price

	Z1	Z2	Z3	Z4	Z5	Z6	Z7
OFF	74%	84%	84%	84%	85%	86%	86%
ON	88%	74%	86%	86%	86%	87%	87%
PV	90%	91%	94%	94%	92%	94%	94%

Note: Defined as output-weighted SMC/GB time-weighted SMC (simple average of zonal prices)

8. Conclusions

High VRE penetration necessarily implies economic curtailment as the cost of investing to use surplus power (exporting, storage, demand side response) rises rapidly. Earlier work showed that different VRE technologies with their specific output time profiles interact to magnify the impact of expanding any one technology, as it will interact with and increase the curtailment of other technologies. This article extends that analysis to show that expanding VRE in one location will interact across space in complex ways when internal transmission constraints and their congestion are recognised. Zonal boundaries, defined by significant transfer constraints, shift increments in VRE output within GB to other zones and externally through interconnectors. The results further amplify marginal curtailment, raising marginal costs by up to 90%. If (or when) the Continent meets its more challenging NCEP targets, curtailment will increase (by 60%), further raising investment costs.

The results show that expanding VRE in Scotland is very costly compared to more central zones, even for wind locations with high capacity factors. In contrast, all VRE in central and southern zones Z4-Z7 look competitive against each other, and apparently cheaper than new nuclear power, at least ignoring system integration costs (providing inertia, transmission and storage). They warn that exporting surplus GB VRE will become harder as the Continent expands its VRE, and curtailment rates will rise.

The difference between recognising internal transmission constraints and ignoring them (as in the copper plate model) is considerable. It gives an idea of the size of redispatch costs needed to address congestion, although we have not calculated the extra system costs of that redispatch.

9. Caveats

The UCED model is able to capture many, but not all, of the constraints needed to ensure system stability and resilience. For example, the System Operator needs to carry fast-responding reserves to deal with the largest possible single sudden loss of infeed, such as a generator failing or a transmission link or interconnector disconnecting. Different speeds of response are required, the fastest often best supplied by pumped storage and batteries.[16] This may reduce their availability for time shifting output to absorb surplus VRE, so may lead to an underestimate of VRE curtailment in the model. Reserve requirements and other ancillary services such as voltage control will increase the cost of managing the system, and to the extent that VRE increases their demand, system costs attributable to VRE will not be captured by our model.

We already noted that the model is sensitive to the order in which VRE is curtailed. Within-zone the model curtails first on-shore wind, then offshore wind and finally PV, reflecting their decreasing avoidable costs, giving a total zonal curtailment that could be allocated pro-rata according to zonal VRE offers. How curtailment is allocated within the zone does not affect the total VRE curtailment caused by increasing VRE capacity, nor for measuring marginal curtailment and cost. Between zones the correct curtailment order is less obvious as within any asset class avoidable costs are identical, and so it might seem arbitrary which other zone's VRE should be curtailed. Our preferred solution was to favour

[16] https://www.neso.energy/news/new-fast-frequency-product-boost-national-grid-esos-response-capability

neighbouring zones by imposing a transmission marginal cost that increases the further away the zone is from the surplus zone. This is an approximation to the marginal loss factors which are roughly proportional to distance. Another solution giving similar results is to levy a cross-border charge per MWh, which increasingly penalises multi-zonal transfers, but seems rather crude in comparison.

As curtailment is highly non-linear, the results could be sensitive to the size of the increment chosen. As the aim is to measure marginal curtailment, the trade-off is to choose a sufficiently large increment (0.9% for offshore wind, 3.1% for onshore wind, and 6.7% for PV, which at the national level deliver an average potential average hourly increment of 200 MW) to avoid rounding errors in the optimization, but not so large that the increment is no longer marginal. Earlier tests with the copper plate model reported in Newbery and Chyong (2025) found almost complete linearity of the marginal curtailment for a trebling of increments.

A natural objection to any simple use of our marginal cost results is that, like most published levelised cost calculations, they assume an unchanged future. This is not so much a criticism of the concept of marginal cost, but of its measurement in a dynamic system. We argue that such system modelling of possible futures should always compute perturbations of the current investments to determine their present discounted impact on the future. As we are not undertaking a dynamic simulation, the purpose has been to illustrate the potential importance of marginal curtailment for allocating near-term investments more intelligently across space. As the system evolves with more transmission and generation investment, the initial point will change and with it the associated set of marginal costs. But for the present the measures give clear policy relevant signals about where and where not to encourage different VRE investments in the near future.

There are a related set of policy implications about designing support systems, market designs, grid charges and grid access regimes that have already been subject to much analysis, and which prompted the REMA consultation in section 1 and were partly addressed in the literature review. In contrast the purpose of this article is to highlight the complexities of tracing through the ripple of marginal curtailments caused by locational VRE investments. Naturally they are system specific, and will change over time with investments and will differ between systems, but this article demonstrates that they are likely to be material and highly relevant for efficient system expansion. In the case of Britain, it greatly strengthens the case for avoiding more investment behind highly constrained boundaries, as the marginal costs of delivery from such locations are far higher than normally reported (or considered in location-blind auctions).

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Appendix A: Data Sources for the Pan-European Electricity and Hydrogen Dispatch Model

This appendix lists data sources and their processing and transformation calibrated to projections from the *Future Energy Scenarios Hydrogen Evolution* and ENTSO-E *TYNDP 2022*. It also describes GB's interconnector capacity and storage capacity in 2023.

Demand

The model considers 19 European national electricity markets (Table A.1), divided into 28 zones to explicitly consider key sub-national transmission constraints for GB (7 zones), Denmark (2 zones), and Norway (3 Zones). Annual demand (in TWh) is for *Hydrogen Evolution* (ESO, 2024b).[17] Annual projections were multiplied by hourly load profiles to give hourly load time series for the dispatch model. The hourly profiles were taken from PECD (2021). The 1998 climate year was chosen to represent a normal year (Ah-Voun et al., 2024) to preserve spatial correlation between GB and European markets and hourly wind and solar capacity factors (from ***TYNDP 2022***, Appendix VI: Demand). 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.). All inputs will be available at https://github.com/KongChyong

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

Country	Country Code	2030	Country	Country Code	2030
GB1	GB	5.87	Spain	ES	286.63
GB2	GB	15.85	Finland	FI	103.15
GB3	GB	14.57	France	FR	516.22
GB4	GB	56.00	Italy	IT	380.75
GB5	GB	178.05	Luxembourg	LU	9.01
GB6	GB	5.73	Netherlands	NL	180.39
GB7	GB	38.29	Norway	NO	170.26
Austria	AT	84.35	Poland	PL	197.6
Belgium	BE	99.47	Portugal	PT	60.88
Switzerland	CH	71.68	Sweden	SE	168.69
Czech Republic	CZ	80.96	SEM	SEM	52.17
Germany	DE	684.36	Slovenia	SI	16.59
Denmark	DK	54.42			

Generation

Electricity generation in the model includes gas, thermal coal, oil, biomass, low-carbon hydrogen, nuclear, solar, wind, and other renewable supplies (RES, such as marine and waste energy). Gross installed capacity was taken from *FES HE* scenario 2030 for GB (tab "ES1") and Europe (tab "ES2"). Table A.3 reports the total installed generation capacity per country in the model.

Technoeconomic parameters such as ramp rates, minimum up and downtime, start and shut down costs, thermal efficiency, and variable operating and maintenance (non-fuel)

[17] GB demand is at tab ES1, EU demand at tab ES2.

costs of dispatchable generation were primarily taken from ENTSOE's *ERAA 2023 Study*.[18] All costs and prices used in the model are Euro 2023 prices.

The installed capacities were primarily sourced from the *FES HE* scenario (ESO, 2024) dataset, with GB-wide solar and wind hourly capacity factor (CF) profiles obtained from the PECD (2021) for the 1998 climate year. The GB zonal VRE capacity factors were sourced from https://www.renewables.ninja/ selecting representative NUTS-2 regional hourly CFs and adjusted as explained below to give the final CFs, whose zonal averages are given in Table A.2. 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.

The PECD climate data base for Europe treats GB as a single zone. Further, the PECD database is a composite "normal" climate year rather than a specific year, although it is based on 1998 data. Its correlation with the actual Ninja data[19] for GB onshore wind in 1998 is 99%, and that is the year chosen for downloading Ninja data at NUTS geographical level disaggregation at hourly resolution. Zonal values took the one or two NUTS regions with the highest average CFs (see Table A.2), and averaged them, on the basis that developers would choose the most favourable locations within zones. Offshore hourly CFs are taken from the nearest onshore NUTS (in some cases the average of the east and west coast values). For PV, representative zonal longitude and latitudes were used to download suitable Ninja CFs, then scaled as for other VRE.

The resulting zonal hourly capacity factors ($CF_{z,h}$) reflect the cross-zonal correlations of weather. A consistent zonal VRE hourly output involves scaling $CF_{z,h}$ to preserve the GB-level zonal aggregate output correlation with the PECD GB data. The first step involved scaling and then flattening the $CF_{z,h}$ to ensure that they remain within the range [0%,100%]. Let $\sum_z CF_{z,h}K_z / Y_h = \theta_h$ be a scaling factor, where Y_h is the PECD hourly output. As this varies between 0.16 and 1.54 for onshore wind, simply scaling by this factor would produce CFs outside the acceptable range. The next adjustment is first, to scale the original $CF_{z,h}$ to revised CFs: $CF^*_{z,h} = 0.5\theta_h + (1- 0.5\theta_h{*}\ CF_{z,h})$ and then rescale by a further scaling factor $\varphi_h = \sum_z CF^*_{z,h}K_z / Y_h$, which gives a GB hourly aggregate equal to the PECD value and preserves the cross-zonal correlations. The same approach was followed for offshore wind except for the few cases where the resulting $CF_{z,h}$ was above 100% when its value was capped at 100%. It should be recognised that actual windfarms might have quite different CFs even in the same zone, but the purpose of the zonal exercise is to capture boundary constraints in any hour, and for that good correlations within the zone are more important than the actual CFs.

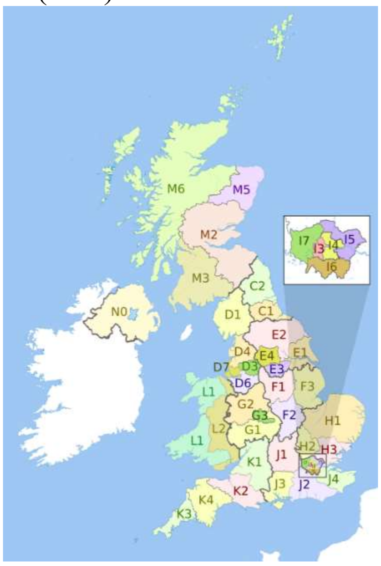
[18] The original source for these parameters is the worksheet titled "Thermal Properties" within the Excel file named "ERAA2023 PEMMDB Generation.xlsx", derived from the Pan-European Market Modelling Database.

[19] From Renewables.ninja Wind (NUTS-2 hourly data, 1980-2019) - ninja_wind_country_GB_merra-2_nuts-2_corrected - Version: 1.3 - License: https://creativecommons.org/licenses/by-nc/4.0/ - Reference: https://doi.org/10.1016/j.energy.2019.08.060

This method fails for PV as the scaling factors can be too high and produce improbable hourly CFs, so these were capped at the centred monthly NUTS zonal values, then scaled hourly to be consistent with the PECF GB hourly values and finally capped at the maximum value of the original zonal CFs. Table A.2 gives the NUTS 2 zones used for onshore wind CFs while the map shows their location.[20]

Table A. 2: GB Zonal wind and solar potential capacity factors (PCF)

Zone	NUTS2	OFF	ON	PV
Z 1	M5-6	49.2%	28.0%	8.8%
Z 2	M2-3	49.4%	27.9%	9.3%
Z 3	C2,D1	51.5%	28.7%	10.3%
Z 4	L1,E1	53.4%	28.4%	9.9%
Z 5	F3,L1	54.1%	29.0%	10.8%
Z 6	H1	53.1%	28.9%	11.5%
Z 7	K2, J2	49.1%	27.8%	11.9%
GB		52.2%	28.2%	10.8%



At present NESO charges intermittent generators an annual charge in £/kW that depends on location. The charge is made up of a year-round shared element x Average CF + a year-round non-shared element + adjustment tariff. If a transmission-connected generator is directly connected to a substation defined as a Main Interconnected Transmission System (MITS) node, then they will only need to pay the onshore local substation tariff.[21] The following table starts from the assumed grid and connection charges that are already included in the Levelised Cost of Electricity (LCoE) charges in BEIS (2020, 2023) and adds deviations of the TNUoS zonal charge from the average across all NESO zones (on the assumption that the LCoEs used average figures). Thus in Z1 the TNUoS charge for offshore wind is £25.34/kWyear but the average is £8.52/kWyr. and this is deducted to give an additional charge of £16.83/kWyr. to add to the LCoE. The results are shown in text Table 9.

[20] At https://commons.wikimedia.org/wiki/File:NUTS_2_statistical_regions_of_the_United_Kingdom_2015_map.svg

[21] https://www.neso.energy/document/130271/download

Table A. 3: 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**
GB1	86		2,309	52		85	743	6,930		4,356	**14,561**
GB2	62		38	52		40	628	9,672		3,516	**14,009**
GB3	366		392	52		299	1,530	908		2,890	**6,437**
GB4	2,248		11,101	52		1,252	3,730	2,071		11,785	**32,240**
GB5	1,111		23,911	52		3,747	14,598	2,698	2,709	5,824	**54,649**
GB6	69		1,234	52		82	1,098	271	1,861	11,708	**16,375**
GB7	285		4,426	52		314	5,318	530		3,399	**14,323**
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**

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 A.4). All storage and DSR assumptions are taken from ESO (2024) and ENTSOe (2024). Hydro energy inflow data, discharge and charge capacities for the modelled market zones are derived from the Pan-European Market Modelling Database (PEMMDB),[22] part of the *ERAA2023* study. Hydro inflows are sourced from the "Storage_technology – Year Dependent" sheet in files accessible via Hydro Inflows ZIP,[23] with the reference year set to 1998 under 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 ESO (2024), 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).

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 (in 2023, this is 1.24 GW, according to FES HE). Further, FES HE 2030 assumes 8.16 GW of

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

demand flexibility from smart charging (1.97 GW) and flexibility from domestic and industrial heat storage, hybrid heat pumps and thermal storage (in 2023, this is 6.04 GW, according to FES HE). Thus, in the FES HE scenario, GB is projected to have 10.22 GW of demand-side flexibility by 2030. Overall, this flexibility level is rather ambitious and sits at the high end of forecasts from other stakeholders and institutions (e.g., according to Torriti (2024), Carbon Trust and Imperial College London forecast optimal DSR capacity to be between 4.1 GW and 11.4 GW by 2030). Our dispatch model assumes 2.07 GW of implicit DSR (load shifting) and another 6.19 GW of peak shaving (taken from ERAA 2023 PEMMDB), totalling 8.25 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. Thus, their discharge, charge and volume capacities for compressed air and liquid air storage are derived from FES data. Data for these storage technologies from other regions is unavailable.

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 for zones without specific data are assumed to be 3 hours for compressed air[24] and 5 hours for liquid air (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).

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

Table A. 4: 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
GB1	369	2	42	4
GB2	5694	3	105	4
GB3	883	2	95	4
GB4	9,397	5	369	4
GB5	7,182	2	1,159	4
GB6	319	2	42	4
GB7	2,504	2	253	4
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

Network

The network data for interconnections (IC) 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[25] 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. By 2030, GB is projected to have 14,514 MW of interconnection capacity with the rest of Europe:

1. 2,400 MW with Belgium (NEMO with 1000 MW connected to GB7 and Chronos with 1400 MW connected to GB5)
2. 1,400 MW with Germany (Neuconnect with 1400 MW connected to GB5)
3. 1,400 MW with Denmark (Viking Link with 1400 MW connected to GB5)
4. 1000 MW with the Netherlands (Britned with 1000 MW connected to GB5)
5. 1,464 MW with Norway (NSL with 1464 MW connected to GB3)
6. 1,450 MW with the Island of Ireland (Moyle with 450 MW connected to GB2, EWIC with 500 MW connected to GB4, and GreenLink with 500 MW connected to GB5)
7. 5,400 MW with France (IFA1 and IFA2 with 3000 MW connected to GB7, ElecLink with 1000 MW connected to GB7, and Gridlink with 1400 MW connected to GB5)

In 2023, GB's total interconnection capacity was 8464 MW. The final dataset includes the processed NTC values and interconnections availability profiles, incorporating the adjustments for GB sub-zones. Zone Z2, Z4 and Z5 are connected to the SEM, Z5 also to BE, DE, DK, FR and NL. Z7 is also connected to FR.

Costs and prices

Load curtailment cost is assumed to be €4,000/MWh-e, which aligns with the ERAA 2023 price cap assumption. Carbon prices for the GB and European power markets are assumed to be €107/tCO_2 and €86/tCO_2, respectively.[26] Fuel prices were sourced from FES 2024 (taking 2023 gas, coal and oil prices) and from the BEIS (2023) Electricity Generation Costs 2023 report (Table A.5).

Table A.5 Assumed fuel prices

	€2023 per MWh-th
Coal	14.52
Oil	53.69
Gas	40.42
Dedicated biomass	11.83
Biomass CHP	14.64
Biomass CCS*	22.02

Notes: * BEIS (2020) and ESO (2024) for coal, oil and gas prices

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

1. Other RES: €40.53/MWh-e.

[25] https://www.ofgem.gov.uk/energy-policy-and-regulation/policy-and-regulatory-programmes/interconnectors
[26] These carbon price levels were observed in 2023, based on *FES 2024*

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.

It should be noted that the 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. An alternative approach to ensuring that nuclear has minimal curtailment is to require longer up and down time and very low ramp rates. However, these features require explicit unit commitments imposed on nuclear, which can be modelled but at further computational complexity. There is evidence on the offer and bid prices that EDF Energy Nuclear Generation makes into the Balancing mechanism[27] – e.g. on 19/08/25 all stations had a spread from £10,000 to -£10,000/MWh, indicating their unwillingness to flex at short notice.

[27] https://bmrs.elexon.co.uk/balancing-mechanism-market-view

Appendix B: Additional results

Table B1 shows the full impact of increasing each VRE one zone at a time, and amplifies table 8 – the final column is the one shown in that table. Thus the 166 GWh of potential offshore wind expansion in Z1 results in 38 GWh curtailment in Z1, 14 GWh in Z2 and in total the 57 GWh curtailment shown in Table 8. The table shows that even for expansions far from Z1 and Z2 most of the curtailment takes place in those zones.

Table B1 Full zonal impact of individual VRE increments

Individual expansions		Z1	Z2	Z3	Z4	Z5	Z6	Z7	Total
OFF Curtailment GWh	Z1	38	14	1	1	2	0	1	57
	Z2	28	16	1	1	2	-0	1	48
	Z3	6	10	1	1	2	0	0	20
	Z4	37	38	4	3	2	0	1	84
	Z5	11	21	2	2	3	0	1	39
	Z6	36	30	4	3	7	0	1	80
	Z7	10	8	1	1	2	0	0	22
ON Curtailment GWh	Z1	240	7	0	0	1	-0	0	249
	Z2	176	161	1	0	0	-0	0	339
	Z3	1	5	8	-0	2	-0	0	15
	Z4	12	11	1	17	-1	-0	0	39
	Z5	9	16	2	1	18	0	1	48
	Z6	-7	1	0	0	0	2	-0	-3
	Z7	1	2	0	0	-1	-0	4	6
PV Curtailment GWh	Z1	2	5	0	0	2	0	0	10
	Z2	5	2	0	0	2	0	-0	9
	Z3	5	3	1	0	1	0	0	11
	Z4	5	14	1	1	0	1	1	22
	Z5	48	45	5	7	6	1	3	115
	Z6	9	3	1	0	-0	-0	0	13
	Z7	16	15	3	1	2	0	1	38

Table B2 Impact of expanding VRE in Z5 with high EU VRE

High VRE		Z1	Z2	Z3	Z4	Z5	Z6	Z7	Total	normal	delta
curtailment GWh	OFF	8	28	4	7	5	2	2	56	39	44%
	ON	7	26	3	10	34	1	2	83	48	72%
	PV	51	75	13	17	7	3	5	172	115	50%

Table B1 shows that at the level of individual expansions in the central part of the country (Z5) High EU VRE increases curtailment by between 44% and 72%.

Extra Appendix References

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