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Implications of Renewable Electricity Curtailment for Delivered Costs

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Abstract

At high penetration levels, the ratio of the marginal: average curtailment (*mc/ac*) of an extra MW of wind is typically 3+ times its average. For a portfolio of on- and off-shore wind and solar PV, the ratio is considerably higher. With increasing methods of using potentially surplus VRE (exports, storage) average curtailment falls but the *mc/ac* ratio rises. The marginal levelised cost of VRE is inversely proportional to the Marginal Capacity Factor, which falls as marginal curtailment increases, raising concerns that reducing average curtailment may not lower the marginal cost of VRE. This paper proves this is not the case. Reducing curtailment has a magnified effect on marginal curtailment and does indeed lower the marginal cost of VRE.

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

JEL Classification L94; Q42; Q48

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Implications of Renewable Electricity Curtailment for Delivered Costs

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1. Introduction

Governments and other agencies setting decarbonisation targets and designing Variable Renewable Electricity (VRE) support mechanisms usually rank alternative technologies by their Levelised Cost of Electricity, LCoE), calculated as follows. If the cost of installing a MW of capacity (including the cost of the site, engineering works, and accumulating the cost of finance until commissioning (see BEIS, 2023) is K, then the capital cost per year is found by annuitizing this sum over its lifetime, T years, at a suitable real weighted average cost of capital (WACC) of r. The WACC will depend on the degree of risk of the investment, which may be substantially reduced with a suitable contract. Thus if $\beta = 1/(1+r)$, the annuitized annual value is $A = rK/(1-\beta^T)$. The annual total fixed cost per MW is then $F = A + f$, where f is the annual cost per MW of other fixed costs (e.g. grid connection costs, insurance, etc.). For VRE with a potential capacity factor (PCF, as a percentage) the LCoE is F/(PCF*8760) + v, where v is the variable O&M cost in £/MWh.

As an example, BEIS (2023) gives the overnight cost[3] of onshore wind in 2018 prices as £1,120/kW (for 2030 commissioning) or £1,356/kW accumulating interest during construction at 5%. With a 25yr life A = £96,202/MWyr. As f is given as £29,500/MWyr, v = £6/MWh, so LCoE = £42.20+£6 = £48.20/MWh. Offshore wind has a higher capital cost (£1,975/kW with interest) but a longer life (30yrs) giving A = £128,464, higher f = £92,500/MWyr, lower v = £3/MWh, higher PCF (60% for 2030), so the LCoE = £44.25+£3= £47.25/MWh, cheaper than onshore wind (although the ratio of investment cost is 46% higher per kW). Clearly capacity factors make a considerable difference to the LCoEs. The theme of this article is to investigate the difference between, and varying importance of, the potential capacity factor used above, the average capacity experienced once curtailment occurs, and the marginal capacity factor, which determines the output contribution of the last MW of VRE installed.

Figure 1 shows a range of technologies and their LCoEs, taken from the same source, BEIS (2023). It shows that all VRE are of comparable cost (for 2025 delivery) and far cheaper than new gas-fired Combined Cycle Gas Turbines, where the carbon cost dominates the delivered cost. The carbon price used in figure 1 has been raised to about £250/tonne CO_{2e} (+/- £125/t) rising at 1.5% real per year.[4] Even at the forward EU emissions trading prices, which for March delivery 2025 is €80/tonne CO_2 (£68/t), the additional carbon price would make CCGT considerably more costly than VRE. The question addressed here is whether the LCoE as defined is an appropriate measure for VRE, and whether a more appropriate measure would change the relative costs of different options.

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[3] The simple sum of annual payments until commissioning, as if delivered "overnight".
[4] https://www.gov.uk/government/publications/valuing-greenhouse-gas-emissions-in-policy-appraisal/valuation-of-greenhouse-gas-emissions-for-policy-appraisal-and-evaluation

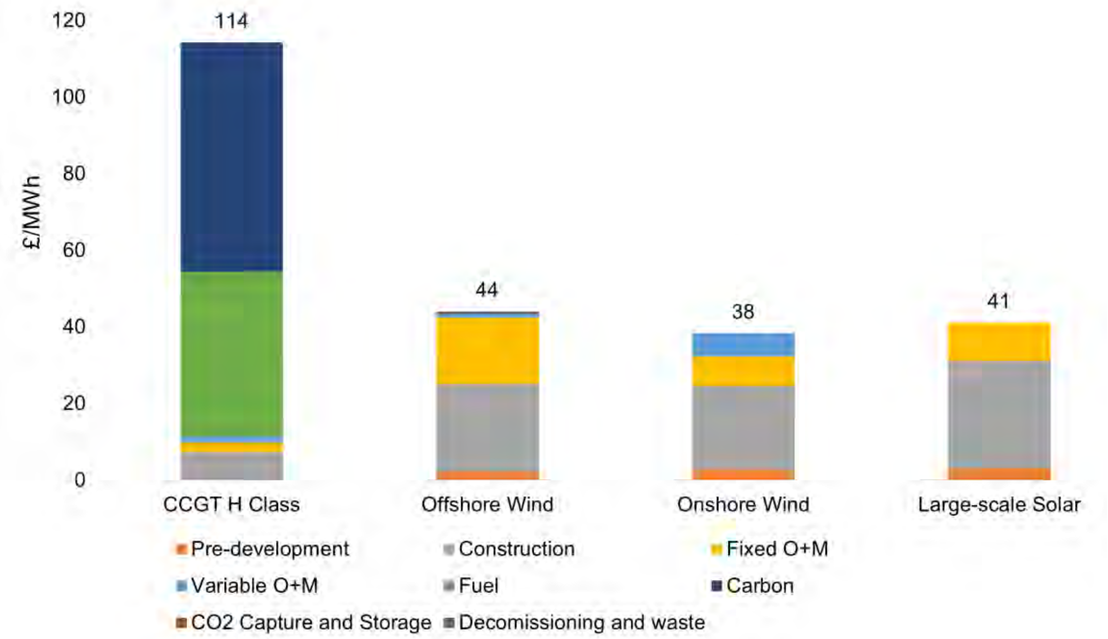

Figure 1 LCOE estimates for projects commissioning in 2025, in real 2021 prices
Source: BEIS (2023).

2. Renewable Electricity costs

The usual objections to the LCoE concept applied to VRE is that it excludes a variety of additional costs needed to integrate VRE into the system, such as providing inertia and other stability services, back-up power when unavailable, etc. (Heptonstall and Gross, 2020). Recognising both their importance and system dependence (notably, on VRE penetration and system flexibility), this article concentrates on a neglected cost aspect of VRE that becomes critically important at the high penetration levels only recently experienced. As the ratio of peak to average output is high for VRE (3-4: 1 for onshore wind, 2-3: 1 for offshore wind and 4-9: 1 for solar PV), high average penetration inevitably leads to the need to turn down or curtail VRE output, for two difference reasons.

Transmission limits lead to local *constraints*, while system-wide stability requirements, most importantly, the need for adequate inertia to prevent too rapid a fall in frequency with supply dips, lead to system-wide *curtailment*. The Single Electricity Market (SEM) of the Island of Ireland currently restricts wind penetration to 75% of demand, to leave space for spinning turbines to provide the required inertia. SEM (2024) helpfully defines and distinguishes between constraints and curtailment. O'Shaughnessy et al. (2020) find that in Arizona and Hawaii, PV is already *curtailed* (about 3%) because of excess supply, while Texas and other countries *constrain* PV because of transmission constraints. For present purposes both curtailing VRE because of transmission limits and system requirements raise the same issues, although relaxing each typically requires different approaches.

Scotland has experienced high levels of constraint, shown in figure 2, while in 2020 the SEM with a wind share of 34% of total generation had to dispatch down 12.1% of wind output, 6.2% because of transmission *constraints* and 5.9% *curtailed* because of system-wide limits (the 75% limit of penetration, Eirgrid/SONI, 2023). Most sources are not so careful in distinguishing between the two and typically label both as curtailment (as in the source for Figure 2) but as this paper addresses both reasons for curtailment that is less important here.

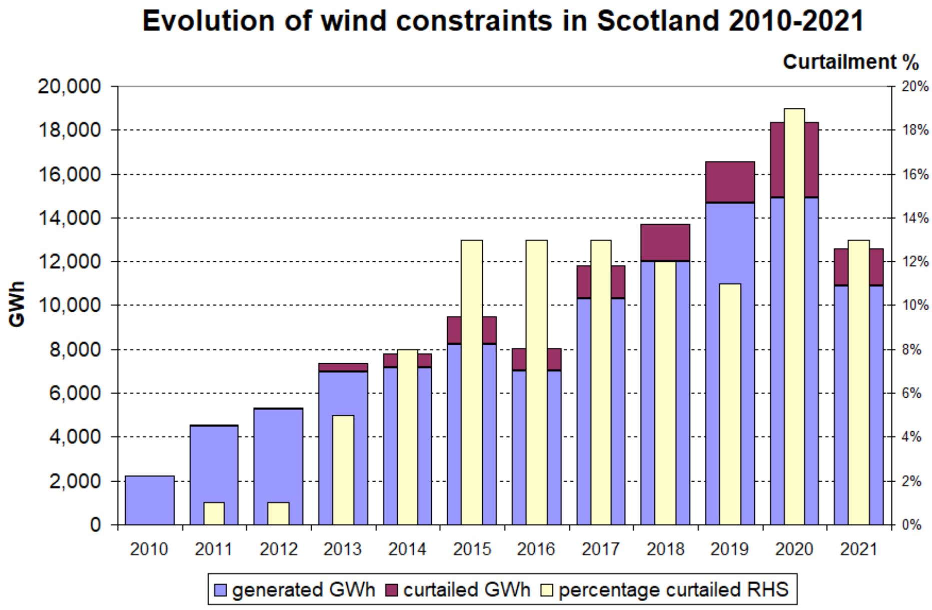

Figure 2 Scottish wind curtailment, mostly from transmission constraints
Source: Renewable Energy Foundation at https://www.ref.org.uk/ref-blog/371-constraint-payments-to-wind-power-in-2020-and-2021

Economists have long argued that it is *marginal*, not *average* cost that determines efficient allocation, and similarly with VRE it is the marginal cost of delivered power that determines their contribution to and cost of decarbonising electricity. That in turn depends on their *marginal* capacity factor, MCF, derived below. All the examples cited above give the average curtailment, and only recently has any attention been directed to measuring and analysing marginal curtailment. Newbery (2023a) argued that the marginal: average curtailment ratio (*mc/ac*)[5] was likely to be 3-4 or more, and estimated its value for the projected wind share in the SEM in 2026, under the two jurisdictions' *National Energy and Climate Plans* (DCCAE, 2019).[6] That study ignored internal transmission constraints and instead concentrated on the impact that the System Non-Synchronous Penetration (SNSP, i.e. the share of wind in total demand) level had for marginal *curtailment* – the 75% noted above. Novan & Wang (2024) estimated in California the average curtailment rate for grid-scale PV was 4.3%, while the marginal rate was more than double at 9.2%.

Simshauser and Newbery (2024) applied the same methodology to examine the implications of marginal curtailment in a Renewable Energy Zone (REZ) located far from the main transmission system in Queensland, Australia. In this case the source of potential curtailment was the limited capacity of the transmission link to the grid. They asked whether average or marginal curtailment was relevant to inviting developers to jointly finance the connection to the grid. They found *mc/ac* ratios of 3.2-3.6 (Simshauser and Newbery, figs. 5,6).

[5] Lower case letters are used for average and marginal curtailment as upper case are used for Average and Marginal Capacity factors.
[6] At the time of writing that paper, Northern Ireland, as part of the UK, did not have a formal NCEP, but by 2022 this had changed with the *Climate Change Act (Northern Ireland) 2022* at https://www.daera-ni.gov.uk/articles/northern-ireland-climate-change-adaptation-programme

Subsequently, Newbery and Biggar (2024) developed a theoretical framework for addressing the export constraint facing the REZ. They compared different pricing (including nodal pricing) and access regimes (pro-rata curtailment or priority dispatch) to compare their impact on the incentives for VRE merchant or market-driven entry and their efficiency. Newbery and Chyong (2025) extended the analysis of single VRE (wind in the SEM) or a composite VRE (wind and PV in Queensland) to a portfolio of different VRE options (on- and off-shore wind and solar PV). They found *mc/ac* ratios for wind ranging from 5 (with the lowest set of options for surplus VRE absorption) rising to 6 (with exports but no storage) to 7.5 (storage and exports) for off-shore wind, higher for on-shore wind (with pro-rata curtailment). Ratios for solar PV varied from 3 – 9. In most cases the variety of different VRE amplified the ratio as each VRE impacted on and increased the curtailment of other VREs, with the ratio rising as average curtailment fell, as shown below.

This paper sets out that theoretical model and extends it to draw out its implications for estimating the appropriate cost of VRE for different market and support designs and for non-linear curtailment schedules. It differs from these earlier papers in extending the analysis to a portfolio of different VRE options, drawing on the empirical data analysed in Newbery and Chyong (2025), and in concentrating on the implications of the *mc/ac* ratio for estimating the Levelised Average and Marginal Costs of Electricity, LACoE and LMCoE.

3. Marginal and average curtailment in a simple model of excess VRE

Figure 3 shows potential VRE (before curtailment) for a 2030 scenario taken from ESO (2024) *Future Energy Scenario Hydrogen Evolution* (FES HE) (as discussed in Newbery and Chyong, 2025).

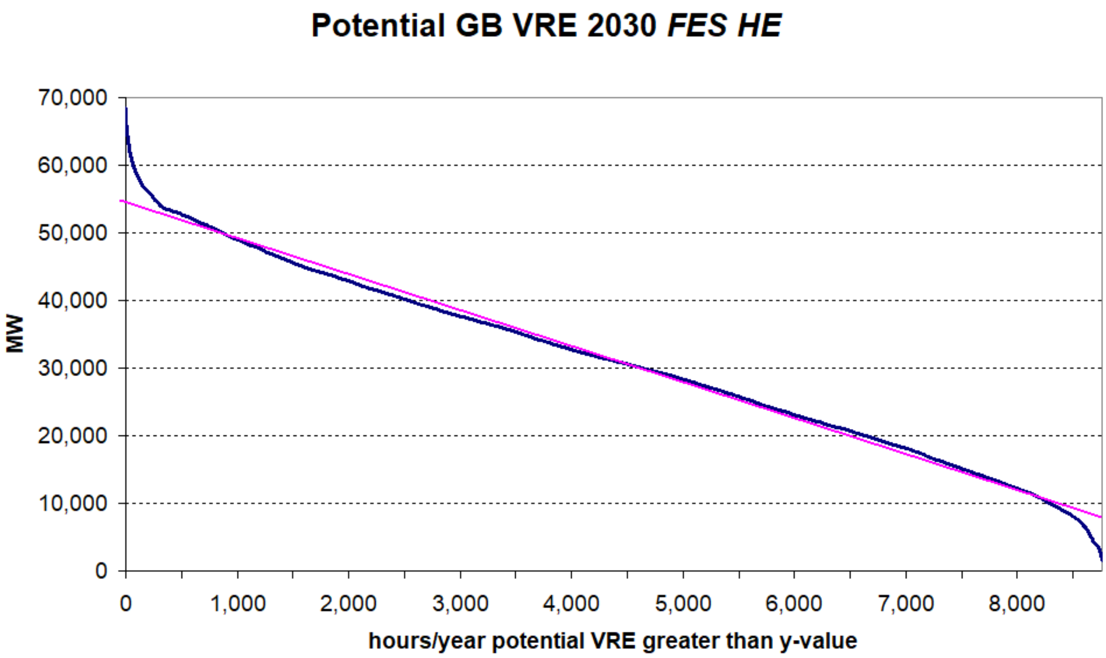

Figure 3 Potential GB 2030 VRE before curtailment, FES HE scenario
Source: ESO (2024) and data from Newbery and Chyong (2025), EU NCEP case

As the superimposed line illustrates, the VRE duration curve is approximately linear over most of its length, as in Newbery and Biggar (2024, fig. 2). This allows for a considerable simplification in deriving marginal and average curtailment, as Figure 4 illustrates for a piecewise approximation to figure 3, although the non-linearity at the top end needs further analysis, discussed below.

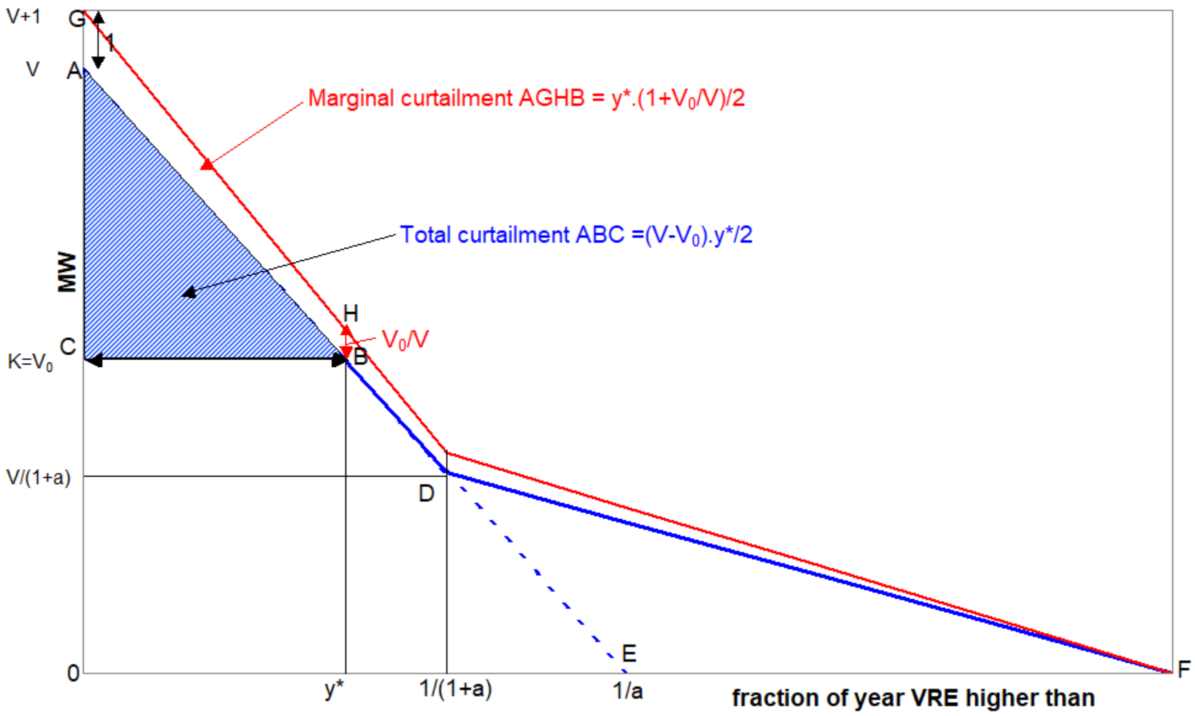

Figure 4 Piecewise linear representation of VRE with curtailment

In figure 4, the original potential VRE duration schedule is ABDF, of which the triangle ACB is curtailed. If VRE is expanded by 1 MW (of peak delivery) the VRE schedule shifts proportionately to the new schedule, GHF (where the shift is proportional to the potential VRE delivered, so point B moves upward to point H by an amount V_0/V, as AG is 1 unit). From simple geometry, total curtailment is the area of ACB = $\frac{1}{2}(V - V_0).y^*$, where V_0 is the capacity of VRE penetration at which curtailment is first necessary, V is the current VRE capacity, and y^* is the number of hours that VRE is curtailed. It also follows that marginal curtailment is the area of the figure AGHB, ½(AG + BH)*AC = $\frac{1}{2}(1 + V_0/V).y^*$ (ignoring the insignificant triangle at the extension of CB).

Average curtailment, *ac*, is total curtailment divided by VRE capacity, while marginal curtailment, *mc*, is from above:

$$ac = \tfrac{1}{2}(V - V_0).y^*/V, \quad mc = \tfrac{1}{2}(1 + V_0/V).y^*, \qquad (1)$$

so the ratio *mc/ac* is

$$mc/ac = (V + V_0)/(V - V_0). \qquad (2)$$

This ratio falls with increases in V and increases with increases in V_0.

Thus far the geometry works as well for a single VRE or a portfolio as shown in Figure 3. It is not, however, immediately obvious that the ratio of *mc/ac* should be higher for a portfolio of VRE than for a single VRE. This is demonstrated more formally in the following simple (but general) model. Suppose that installed capacity of technology j is V_j, (e.g. j = 1 for onshore wind, j = 2 for offshore wind and j = 3 for solar PV). Let its capacity factor in hour h be denoted by θ_{jh}, so that potential output in that hour is $\theta_{jh}V_j$. Let residual demand available to absorb VRE be R_h in hour h and curtailment k_h:

$$k_h = \text{Max}\{0, \textstyle\sum_j \theta_{jh} V_j - R_h\}, \quad (3)$$

If x_h is the pro-rata proportion of curtailment

$$(1 - x_h)\textstyle\sum_j \theta_{jh} V_j = R_h, \text{ if } \sum_j \theta_{jh} V_j - R_h > 0. \quad (4)$$

In cases of positive curtailment, from (3) and (4)

$$k_h = x_h.\textstyle\sum_j \theta_{jh} V_j. \quad (5)$$

If there is a single VRE, wind, say, $V_1 = W$, as in the SEM, then average curtailment, ac, is

$$ac = \textstyle\sum_h x_h.\theta_h/H, \quad (6)$$

where H is the number of hours in the year (8,760). Marginal curtailment, mc, is

$$mc_h = dk_h/dW = x_h.\theta_h + W\theta_h \, dx_h/dW, \quad mc = \textstyle\sum_h mc_h/H, \quad (7)$$

so

$$mc/ac = 1 + W.\textstyle\sum_h dx_h/dW / \sum_h x_h.\theta_h \equiv 1 + \varepsilon_{xW}, \quad (8)$$

where ε_{xW} is the (weighted average) elasticity $d \ln (\sum_h x_h.\theta_h)/d \ln W$.

Now contrast this single VRE case with the portfolio case (5):

$$ac_j = \textstyle\sum_h x_h.\theta_{jh}/H, \quad (9)$$

and

$$mc_{jh} = dk_h/dV_j = x_h.\theta_{jh} + \textstyle\sum_i \theta_{ih} \, dx_h/dV_i, \qquad mc_j = \sum_h mc_{jh}/H. \quad (10)$$

This time the ratio is

$$mc_j/ac_j = 1 + \varepsilon_{xVj} + \textstyle\sum_{i \neq j} \varepsilon_{xVi}. \quad (11)$$

The ratio of each mc/ac thus includes the direct effect visible for a single VRE but in addition the spillover impacts represented by the last term in (11), clearly positive and hence amplifying the ratio.

4. The role of marginal curtailment in cost calculations

The introduction pointed to the importance of the Levelised Cost of Electricity, (LCoE), and showed how it is calculated from the Potential Capacity Factor, PCF. If ACF is the Average and MCF the Marginal Capacity Factors (as percentages), ac the average curtailment and mc the marginal curtailment (also as percentages) of all VRE curtailed as a result of any increment including spill-overs, then for each VRE type j:

$$\text{ACF}_j = \text{PCF}_j - ac_j, \quad (12)$$

$$\text{MCF}_j = \text{PCF}_j - mc_j. \quad (13)$$

Just as LCoE is

$$\text{LCoE} = F_j/(8760 * \text{PCF}_j) + v_j, \quad (14)$$

so the levelised average and marginal cost of any VRE are

$$\text{LACoE} = F_j/(8760^*\text{ACF}_j) + v_j, \tag{15}$$

$$\text{LMCoE} = F_j/(8760^*\text{MCF}_j) + v_j. \tag{16}$$

For the simple case in which $v_j = 0$ (e.g. PV)

$$\text{LMCoE/LACoE} = \text{ACF}_j/\text{MCF}_j. \tag{17}$$

$$\text{LMCoE/LCoE} = \text{PCF}_j/\text{MCF}_j. \tag{18}$$

5. The relevance of different cost measures

The UK Government organises periodic auctions that allocate Contracts-for-Difference with Feed-in Tariffs (CfDs with FiTs) for VRE. This particular contract is for a set strike price, s, determined by the auction, under which the holder sells in the relevant market and receives (or pays) ($s - p$) per MW from or to the Government-backed Low Carbon Contract Company, where p is the reference price.[7] If the VRE is curtailed then it is offered compensation for the difference between the amount it could have dispatched and the amount actually dispatched.[8] As such they have a firm access right to the transmission system with the System Operator.

For example, the latest (Round 6) CfDs with FiTs auction (Sep 2024) cleared at strike prices (£$_{2023}$/MWh) of £67.09 (PV), £68.18 (onshore wind) and £72.65 (offshore wind)[9] when the forward baseload wholesale electricity price in June 2024 was £77/MWh.[10] Thus, all VRE are of apparently comparable cost (as suggested in figure 1) and, at current wholesale prices, do not need subsidy, as noted for offshore wind by Jansen et al. (2020). Bidders in the auction would logically base their bids on the LCoE as they should be paid their offered amount at the strike price even if they are curtailed.

In contrast, in the Australian Renewable Energy Zones described in Simshauser and Newbery (2024) the transmission company builds a merchant connection to the grid with a fixed capacity, whose cost is allocated in proportion to an expected and allowed volume of VRE entry. As developers enter up to the agreed level, they can expect to be curtailed a certain fraction of the time. When curtailment occurs each VRE will be curtailed in proportion to their offered amount (pro-rata curtailment), and so will experience average curtailment. Their business case would logically be based on the LACoE. Newbery and Biggar (2024) showed that if entrants were charged the average cost of the planned capacity of the link (which would anticipate an expected level of curtailment) efficient entry would then result – so for planned transmission constrained VRE LACoE is the correct measure.

Finally, the Irish System Operator, Eirgrid, proposed that "Generators connecting to parts of the network with spare capacity could receive firm access. Generators in parts of the network with limited capacity could connect on a non-firm basis, in advance of the completion of reinforcements, but would not receive compensation if they are dispatched

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[7] https://assets.publishing.service.gov.uk/media/5a79bce4e5274a684690bbdb/7077-electricity-market-reform-annex-a.pdf

[8] See the description of Defined Curtailment Compensation in *FiT CONTRACT FOR DIFFERENCE: STANDARD TERMS AND CONDITIONS* at https://assets.publishing.service.gov.uk/media/61e04175d3bf7f054db937f6/AR4_Standard_Terms_and_Conditions.pdf

[9] https://www.gov.uk/government/publications/contracts-for-difference-cfd-allocation-round-6-results

[10] https://www.ofgem.gov.uk/energy-data-and-research/data-portal/wholesale-market-indicators

down." (Eirgrid, 2022, p5). Developers entering constrained parts of the network would be constrained without compensation before incumbents with firm access agreements, who would be compensated for any curtailment. Under such a contract, developers would logically look at the LMCoE when deciding whether to enter.[11]

Clearly different support designs and market access arrangements can have a significant impact on the choice of project, and whether or not the choice is efficient, i.e. cost minimising in delivering the desired electricity, emissions reduction and system stability. The immediate question to address is how various interventions impact curtailment and the different cost measures.

6. Consequences of reducing constraints and curtailment

Transmission constraints are typically addressed for already-connected generation by investing in additional capacity, where the benefit of reduced curtailment can be balanced against the extra cost of relieving the constraint, and where innovative solutions might be cheaper. For new entrants, strong locational price signals should guide developers to unconstrained parts of the network. The UK Government consulted on a *Review of Electricity Market Arrangements* in 2022,[12] drawing attention to the importance of locational pricing for reducing the cost of resolving transmission constraints. For the considerable volume of VRE connected to the distribution network (132kV and below in GB) firm connections require the generator to pay the cost of reinforcements needed to justify firmness (and the right for compensation for curtailment). It is also possible to request a non-firm connection usually at a considerable cost-saving as costly reinforcement is avoided. This may come with a guaranteed minimum level of curtailment and is thus comparable to the REZ case discussed above.[13]

Curtailment for system stability reasons is less straightforward. The acceptable level of SNSP (which includes VRE, but also DC interconnectors and any power source lacking the inertia of spinning mass like a turbine) can be increased by raising the acceptable rate of change of frequency (RoCoF), which normally requires possibly costly adjustments to control settings, or introducing synthetic inertia by power electronics. Thus the SEM increased RoCoF from 0.5 to 1 herz/second in order to raise SNSP to a target of 75% by 2020. The more direct solution is to increase demand, for if the SNSP limit is say 90%, then an increase in demand of 100 MW can facilitate an extra 90MW of VRE before curtailment. The two obvious method are to build interconnectors for exporting surplus VRE, and storage to absorb excess VRE. Creating new demand for e.g. green hydrogen through electrolysis can also help absorb excess VRE, as can some demand side response, shifting demand from low VRE to high VRE periods.

In both cases average curtailment, ac, should fall by raising V_0, but that raises the mc/ac ratio, and it is marginal cost and hence mc that is relevant for efficient choices. The central question of this article is whether lowering ac also lowers the MCF. As noted from equation (1) in the linear case, lowering ac is equivalent to raising V_0, and so we need to find whether this raises the MCF towards the PCF and so lowering the LMCoE. This is

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[11] Eirgrid (2024, p9) notes that 4,355 MW of wind and solar had applied for non-firm connections

[12] https://www.gov.uk/government/collections/review-of-electricity-market-arrangements-rema

[13] See https://smarter.energynetworks.org/projects/ukpnt202/

equivalent to showing that *mc* falls as V_0 rises. At first sight, differentiating equation (1) by V_0 would seem to deliver a positive value, which would lower the MCF, but that is to ignore the term $\mathrm{d}y^*/\mathrm{d}V_0$, which needs to be evaluated. In figure 4, if the angle BAC = α, then $y^* = \alpha(V - V_0)$, so equation (1) can be rewritten

$$mc = \tfrac{1}{2}\alpha(V + V_0).(V - V_0)/V, \tag{18}$$

so

$$\mathrm{d}(mc)/\mathrm{d}V_0 = -\alpha V_0/V, \tag{19}$$

which is negative. Consequently, MCF rises with V_0 and LMCoE falls. The next question is whether this holds true for the more general non-linear case of figure 5.

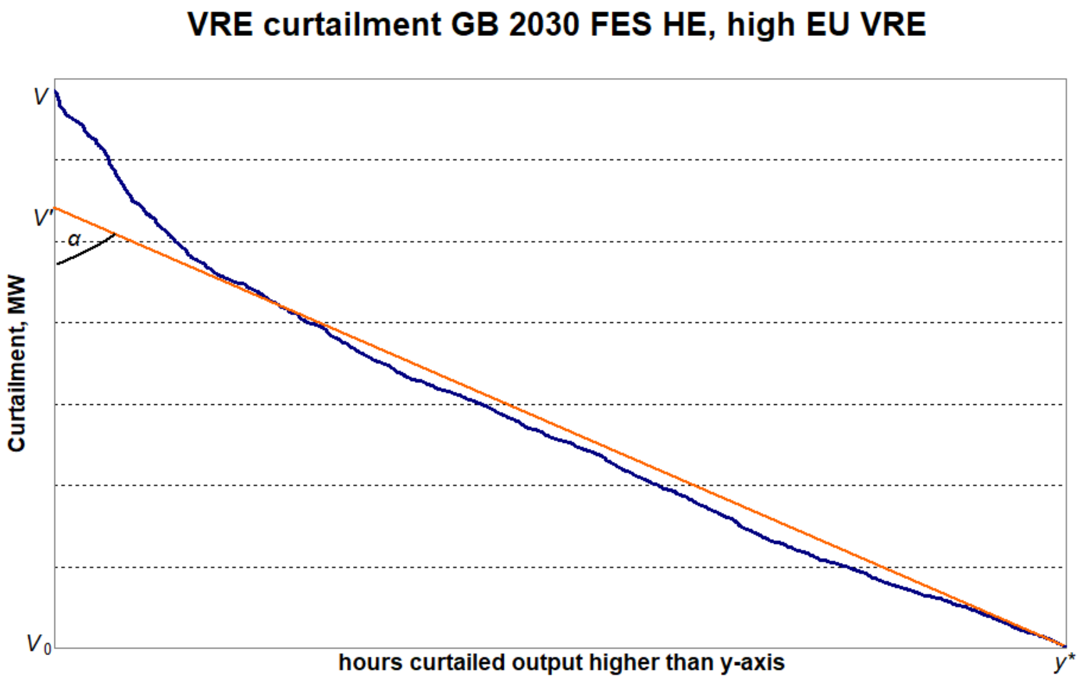

Figure 5 More realistic shape of curtailment schedule
Source: As for Figure 3 but restricted to curtailed hours.

Figure 5 shows that for high levels of V_0 the actual curtailment schedule corresponding to the VRE of figure 3 is more like a piece-wise linear schedule than the simple linear schedule of the curtailed section of figure 4. In this case the (negative) slope of the curtailment schedule at y^* is $\alpha = y^*/(V' - V_0)$, so $y^* = \alpha(V' - V_0) < \alpha(V - V_0)$. Nevertheless, the same argument applies as in (19), leading to

$$\mathrm{d}(mc)/\,\mathrm{d}V_0 = -\tfrac{1}{2}\alpha(2V_0 + V - V')/V < 0, \tag{20}$$

as before. This gives:

Proposition. If for unchanged VRE, average curtailment is reduced, then the Marginal Curtailment Factor increases and the LMCoE falls, lowering the marginal cost of VRE expansion.
Proof. From (1), if V is unchanged and *ac* falls, then V_0 rises. From (20) if V_0 rises, then *mc* falls and as MCF = PCF – *mc* from (13), MCF rises and LMCoE falls (from 16).

7. Illustrations

Table 1 below uses results from Newbery and Chyong (2025) to illustrate the huge difference between the different cost measures of each VRE depending on the extent to which surplus VRE can be exported (the trade cases), stored, and the extent to which neighbours are saturated with VRE (comparing the FES and NCEP trade cases). In all cases the simple LCoE measure is the same but the others vary as predicted according to changes in the average curtailment rate.

Table 1 Capacity factors and levelised costs, pro-rata curtailment, £(2018)

No trade no storage	OFF	ON	PV large	PV mid
PCF	60%	34%	11%	11%
ACF	58.3%	32.9%	10.7%	10.7%
MCF	49.1%	23.1%	9.6%	9.6%
LCoE £/MWh	£43.04	£48.20	£40.64	£60.96
LACoE £/MWh	£47.80	£53.51	£44.70	£67.05
LMCoE £/MWh	£92.06	£66.80	£51.98	£77.97
Trade no storage				
ACF	58.8%	33.2%	10.8%	10.8%
MCF	51.1%	27.5%	10.3%	10.3%
LACoE £/MWh	£43.90	£49.22	£41.39	£62.09
LMCoE £/MWh	£50.36	£58.18	£43.40	£65.10
FES trade w/storage				
ACF	58.80%	33.20%	10.80%	10.80%
MCF	51.10%	27.50%	10.30%	10.30%
LACoE £/MWh	£43.89	£49.18	£41.46	£62.19
LMCoE £/MWh	£50.38	£58.13	£43.39	£65.08
NECP trade w/storage				
ACF	57.80%	32.60%	10.60%	10.60%
MCF	47.80%	26.50%	7.00%	7.00%
LACoE £/MWh	£44.65	£50.01	£42.30	£63.45
LMCoE £/MWh	£53.72	£60.06	£63.59	£95.38

Note: FES trade is EU VRE under ESO (2024) *FES Hydrogen Evolution*, NCEP assumes the EU meets its 2030 NCEP targets, OFF is offshore wind, ON is onshore wind, PV is grid-scale PV, PV mid is mid-size PV (10-50 kW).
Source: Cost data from BEIS (2023), other data from Newbery and Chyong (2025)[14]

8. Conclusions

The three different measures of the cost of VRE are first, the levelised cost assuming no curtailment (relevant to developers if curtailment is compensated) but not necessarily efficient; second, the cost assuming average curtailment, relevant for merchant (unsubsidized) entry where transmission is built and paid for and is the only source of curtailment; and finally the cost assuming marginal curtailment, relevant where curtailment is a system-wide imperative. Regardless of this, unless complementary actions to reduce curtailment are combined with VRE expansion (as they are in the Queensland Renewable Energy Zones), the marginal cost of expanding a portfolio of different VRE of total capacity, V, (off- and on-

[14] I am indebted to Kong Chyong for permission to use this data

shore wind and solar PV) depends on its marginal, not average curtailment. However, the marginal curtailment can be a large multiple (3 - 9) of average curtailment, and the marginal: average curtailment ratio (*mc/ac*) rises as *ac* falls, raising concerns that efforts to reduce curtailment may not reduce marginal costs.

The argument of this paper is that lowering average curtailment by increasing V_0 (the level of VRE that first gives rise to curtailment) impacts marginal curtailment in two ways: first, it directly raises marginal curtailment, which is proportional to $(V + V_0)$ in the linear case, but second, it also reduces the number of curtailed hours, and as marginal curtailment is also proportional to curtailed hours, the paper proves that this second impact outweighs the first. The algebraic argument extends to the kinds of non-linearity found in practice. Lowering average curtailment does indeed reduce marginal curtailment and hence lowers the marginal cost of VRE.

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