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Research article

Marginal curtailment of wind and solar PV: Transmission constraints, pricing and access regimes for efficient investment☆

David M. Newbery[a,*,1], Darryl R. Biggar[b]

[a] Faculty of Economics, Sidgwick Ave, Cambridge, CB3 9DE, UK
[b] Faculty of Business and Economics, 900 Dandenong Rd, Caulfield East, 3145, Victoria, Australia

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ABSTRACT

As Variable Renewable Energy (VRE) penetration increases in poorly networked areas with suitable VRE resources, transmission constraints will increasingly force VRE curtailment. Under most European market access and pricing arrangements, location and operation decisions are based on average curtailment rates. As the marginal contribution of the last MW of VRE is 3+ times average curtailment, there is a risk of inefficient location and operation. This article compares different pricing and access regimes (including nodal pricing) to compare their impact on the incentives for VRE merchant or market driven entry.

1. Introduction

At the Paris 2015 UN Conference of the Parties COP21 196 signatories announced their intention to produce Nationally Determined Contributions (NDCs) setting out their approach to reducing emissions.[2] At the most recent COP28 in 2023 more than 115 countries promised to triple renewable energy capacity by 2030.[3] Both ambitions will require a massive increase in the proportion of electricity generated by Variable Renewable Electricity (VRE, wind and solar PV).[4] VRE has two important distinguishing characteristics. First, its avoidable costs are low (zero for PV, very low for wind). Second, VRE has a high ratio of peak:average output, 3-4:1 for wind, 4-10:1 for PV, depending on the resource quality. If VRE is to contribute a high share of annual output, peak generation will inevitably exceed demand (including for storage and export) for a significant fraction of the year and real-time wholesale prices could collapse in such periods (Frew et al., 2019, 2021; O'Shaughnessy et al., 2021; Song et al., 2018; Wang et al., 2021). Excess VRE supply will need to be curtailed, meaning that it will be required to inject less than its ability to produce at current levels of wind/sunshine. This concept is to be contrasted with making the economic decision to run at below potential output in order to offer increased output in the balancing market, a common strategy for flexible generation but increasingly seen as a potentially valuable option for VRE (Nelson et al., 2018).

The challenge facing liberalized electricity markets is to adapt pricing, dispatch and access rules to address these two characteristics. Liberalized markets in Europe have adopted market designs that were able to cope reasonably well with the fleet of conventional power stations for which transmission systems had been designed. Generators face zonal or national markets that set prices on the fiction of firm access and no internal constraints, leaving it to balancing markets to ensure final balancing of supply and demand. Zonal prices give clear market signals that determine which plants are in merit (have avoidable costs below that price) and which would be unprofitable to run. With firm access rights and efficient markets, if generation cannot sell otherwise profitable power, it will be compensated its lost profit, with replacement and costlier alternatives paid their variable cost.

The simplification of ignoring locational constraints and their resulting locational scarcity prices was arguably defensible with the adequate reserves and robust transmission systems that European countries inherited at liberalization. Efficient cross-border trade and hence European market integration was finally delivered by market coupling that allowed the efficient use of interconnectors, which, when fully used, would create price differences across these borders. Countries with severe internal constraints could (and some did, like Norway,

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* Corresponding author.
E-mail addresses: dmgn@cam.ac.uk (D.M. Newbery), darryl.biggar@monash.edu (D.R. Biggar).

1 Funding: ESRC RES-152-25-1002 Towards a sustainable energy economy.

2 https://unfccc.int/process-and-meetings/the-paris-agreement.

3 https://ec.europa.eu/commission/presscorner/detail/en/ip_23_6053.

4 A list of acronyms is located at the end of the text.

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Sweden and Italy) chose zonal pricing, in which the country splits into a small number of differently priced zones when transmission constraints limit transfers across zonal boundaries. These spatial price differences go some way to providing locational investment signals and congestion management but are insufficiently granular to cope with rapidly varying wind and PV.

Adequate conventional generation inherited at liberalization ensured system security with adequate system services such as inertia, reserves and adequate ramp rates. If missing markets or policy uncertainty made needed new investment too risky, capacity auctions could be created to determine the missing money required to facilitate entry and guide exit (as in Great Britain and on the island of Ireland). High VRE penetration casts doubt on the adequacy of almost all these features of current European market designs. VRE resources are very differently located to existing fossil and nuclear generators for which transmission was designed. Consequently, they will likely face local transmission constraints more frequently than well-sited existing conventional generation, making their location choices increasingly important (Schermeyer et al., 2018).

Peng and Poudineh (2019) identify a number of flaws in European market design hampering the efficient deployment and use of VRE. The urgency of guiding VRE investment away from high resource areas with limited export capacity has been exacerbated by two undesirable features of most VRE support designs (Kröger and Newbery, 2024). Most contracts pay the same support price regardless of location for a fixed length of time, paying on metred output and frequently compensating for any curtailment. If, in addition, transmission charges are low and/or uniform, this provides an incentive to locate in high resource areas that are typically far from demand centres and with limited export capacity.

This perverse locational signal was dramatically revealed in China, where the initial spurt of VRE development incentivized by a single support price naturally encouraged rapid investment in high resource areas distant from load centres, resulting in very high curtailment rates 16% for wind and 10% for PV in the Northwest in 2018 according to O'Shaughnessy et al. (2021) until transmission was expanded (Zhang et al., 2021) and better price signals adopted (Song et al., 2021). Texas experienced the same high but then falling curtailment as transmission was expanded (Bird et al., 2016; Golden and Paulos, 2015). Of course, an extreme form of reducing internal transmission-related curtailment would be to limit entry until the network has been reinforced, and some countries such as Sweden may do this. As an example of the pressures that countries face in reaching VRE targets and to put pressure on Transmission Owners (TOs), Ofgem, the British energy regulator, implemented *Connect and Manage* in 2009, under which "generation projects are allowed to connect to the transmission system in advance of the completion of the wider transmission reinforcement works" (NG, 2013). Other countries arrange a connection queue with often lengthy delays, but this is not necessarily an efficient solution. Those modelled below.

1.1. Transmission pricing and locational signals

Great Britain (GB) is in the forefront of setting stringent carbon targets for electricity. In 2023, the UK government consulted on the *Review of Electricity Market Arrangements* (REMA) to ensure timely and efficient decarbonization in GB,[5] mainly to be achieved by accelerated delivery of VRE.[6] REMA emphasized the need to improve locational signals for investment, operation and congestion management. Great Britain already has quite strong signals for guiding investment location with its Transmission Network Use of System (TNUoS) charges (an annual fixed charge per kW of connected capacity). The TNUoS charges vary widely across the country (by about £45/kW/yr, twice early capacity market payments) and so are potentially quite powerful investment location signals. They proved to be inadequate to efficiently locate VRE, where high support prices overwhelmed to TNUoS signals (Newbery, 2012). At least some of these distortions can be removed by changing VRE support contracts. Instead of paying on metred output for a fixed number of years it would be preferable to offer financial contracts on deemed output for a fixed number of full operating hours (e.g. 40,000 MWh/MW), reducing the incentive to locate in areas of high capacity factors (Newbery, 2023a). The current TNUoS charges are in theory based on long-run incremental transmission cost but they are adjusted too slowly to avoid upsetting incumbents to give efficient signals to entrants. That could be rectified by offering forward-looking long-term indexed contracts to entrants, leaving incumbents to enjoy their existing charges.

The GB system of locational TNUoS charges could therefore be modified quite simply to better guide location, and might then serve as a better model for European markets, which for the most part make little or no use of locational transmission charges (Newbery, 2023c). ENTSO-E (2022), Table 4.1, shows that of the 36 ENTSO-E[7] member countries only four have transmission locational signals (GB, Ireland, Norway and Sweden). With little need for new conventional capacity, and apparently adequate transmission, most ENTSO-E countries adopted and have kept uniform and often zero transmission charges for generation — only 10 countries have generators contributing more than 4% of total transmission charges. Indeed, the European Commission has mandated (in Commission Regulation (EU) No 838/2010) low average generation transmission charges to level the cross-border playing field, with the required revenue raised from charges on load (final consumption). Great Britain meets this low average by offsetting high charges in some exporting zones with negative charges in major importing zones.

Eicke et al. (2020) widen the analysis of locational signals provided by a range of instruments, choosing interesting examples from across the world.[8] They conclude that each instrument (including fixed TNUoS charges) have strengths and weaknesses which vary with the system characteristics (such as VRE penetration). Perhaps the most interesting examples of successful congestion management come from those countries with Locational Marginal Pricing (LMP or nodal pricing). A large and increasing number of countries have already adopted LMP, starting with New Zealand in 1996, followed by PJM in the US in 1998, adopted in the Standard Market Design by FERC in 2001, and even deployed in the electrically independent state of Texas by ERCOT in 2010. The European Commission has published a report of the JRC setting out the case for LMP, but recognizing the challenges for its EU-wide implementation (Antonopoulos et al., 2020).

The REMA consultation initially asked for views on the suitability of LMP for GB but the second consultation in 2024 ruled them out, at least for the near future, in favour of zonal pricing. Given their potential for addressing rapidly growing congestion, this article will consider LMP as an important potential aspect of market design for high levels of VRE.

The high peak:average ratio of VRE output becomes a problem once supply exceeds demand and VRE needs to be curtailed. Newbery (2021, 2023b) demonstrated that marginal curtailment is typically 3+ times average curtailment (illustrated in Fig. 3 below), and that in current European market designs entry decisions are driven at best by average curtailment. However, while the concept of average curtailment is well recognized (Golden and Paulos, 2015; O'Shaughnessy et al., 2021) the concept of marginal curtailment has been underappreciated, which is surprising given that many authors draw attention to the rapid rise in curtailment with penetration (e.g. Fig. 2 in Frew et al., 2021). The marginal contribution of the last MW will be more heavily curtailed than the average, and so will deliver fewer useful MWh for the same cost.

[5] Ofgem only has responsibility for the regulation of the power sector in GB. The power system in Northern Ireland (which is part of the UK) is regulated as part of the SEM.

[6] https://www.gov.uk/government/consultations/review-of-electricity-market-arrangements.

[7] European Network Transmission System Operators for Electricity.

[8] Chile, France, Germany, India, Mexico, Norway, Sweden, and the United Kingdom, CAISO, PJM, and ERCOT in the United States, and the National Electricity Market (NEM) in eastern and southern Australia.

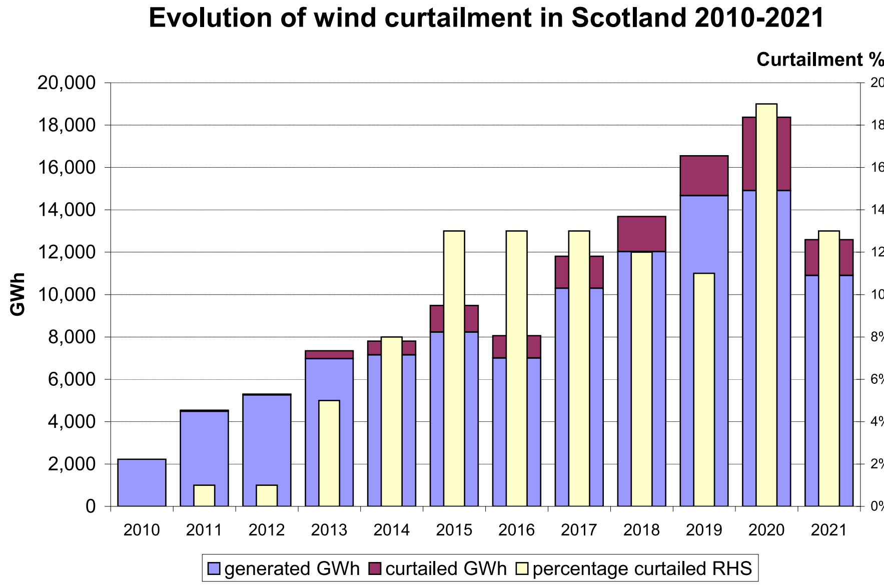

Fig. 1. Evolution of wind output and curtailment in Scotland, 2010–2021.

This article addresses the pressing problem of curtailment caused by the mismatch of transmission and the location of recently entered VRE.[9] Fig. 1 shows on-shore wind curtailment rates in Scotland rising over time, and similar problems have already arisen in other countries where VRE locates in less connected parts of the system (as noted above, China and Texas in particular). Novan and Wang (2024) econometrically estimate marginal curtailment rates for wind and solar PV in California and find that although the average curtailment of solar is only 4.3%, marginal curtailment is 9% or roughly twice as large. In the case of wind, while average curtailment is only 0.4 of 1%, marginal VRE curtailment (mainly solar PV) is 10%. The question addressed is whether existing or potential market designs and access regimes (i.e., who gets curtailed, by how much and with what compensation) give rise to inefficient VRE entry signals, and if so what changes to these rules can resolve the problem. Pricing transmission constraints should be simple and is already addressed in markets with nodal pricing. If the transmission constraint binds, then prices on each side of the constraint will differ, with the difference equal to the scarcity value of the constraint. This article asks whether that is sufficient, and, if nodal pricing has been ruled out, whether there are alternative solutions that can provide efficient VRE investment signals in zonal and uniform pricing regimes.

Major market reforms such as moving to LMP create very considerable transition problems in adjusting existing long-term support contracts for VRE (and other generators who entered after liberalization in the expectation that the then market structure was enduring). New VRE entrants typically bidding in auctions for long-term support contracts offer an opportunity to provide them with more appropriate contracts that specify their rights and charges. In effect they join a Renewable Energy Zone (REZ) with specific rules that apply to the contracts granted in such zones. This article considers what access and curtailment rules should apply to such contracts such that their bidding for contracts is efficient, and what role nodal pricing across the zonal boundary might play, if considered, and if ruled out, what adjustments need to be made to the access regime.

[9] System stability and security reasons for curtailment are addressed in Newbery (2023b) and are not relevant in the case of local transmission constraints.

1.2. Transmission constraints and transmission pricing in a renewable energy zone

Transmission constraints are prevalent and one of the main reasons for real-time pricing or balancing mechanisms. However, even with zonal pricing and/or zonal transmission charges, most zones contain a wide variety of generation assets and demand-side flexibility options as well as VRE, whose efficient dispatch complicates the analysis of VRE curtailment. To keep matters simple this article concentrates on a well-defined set of cases that offer clear insights into the VRE investment decision. The cleanest example is the case of an isolated Renewable Energy Zone (REZ), designed and sized to house VRE and connected by a single link to the main interconnected transmission system (MITS), which is charged to the VRE in proportion to their capacity.

The off-shore wind regime in GB has this structure — the Crown Estate identifies suitable areas of the seabed for development, auctions them to developers who in turn bid for long-term contracts for their output, and if successful, build the wind farm and the connection to the on-shore MITS. This is then auctioned to a financier in return for a regulated charge on the use of the connection that recovers the auction value of the link (Aldersey-Williams et al., 2020; Zhang and Pollitt, 2023; Newbery, 2023c). In Britain many on-shore VRE projects of modest scale are connected to distribution networks, where the access regime is quite different to the MITS. New distribution generation faces deep connection charges, in which the full cost of reinforcing the network is charged to the new connection. Eicke et al. (2020) show that this is also practised at the transmission level in some jurisdictions, and was quite common in the former socialist countries of central Europe. In one of its innovation competitions, Ofgem financed the *Flexible Plug and Play* project.[10] UKPN, the local Distribution Network Owner, offered new wind farms the option of paying the full deep connection charge for firm access, or a much cheaper connection but with the prospect of curtailment up to a certain maximum uncompensated level. This was found to be both very attractive and also completely compatible with the existing regulatory rules and is now widely adopted.

The situation we have in mind (an isolated REZ, hosting a large amount of VRE, connected by a radial link to the MITS) also arises in the state of Queensland in Australia. Powerlink, the state-owned

[10] see e.g. https://www.ofgem.gov.uk/sites/default/files/docs/2015/02/fpp_progress_report_dec_2014_v1.0_pxm_151214_with_signature.pdf.

transmission service provider in Queensland, identifies and responds to the choice of suitable locations for investment in VRE. Powerlink agrees to build a suitable radial link to the grid with one or more 'anchor investors' who are ready to build. end-use consumers, Queensland's REZ model is one of This is a form of merchant investment, paid for by connecting generators. The REZ connection is optimally sized for expansion well beyond the initial VRE proponent's investments, with each user charged only a suitable fraction of the REZ cost. The commercial attractiveness of VRE under this merchant model depends on the fraction of (unrewarded) expected curtailment resulting from future entry of wind and solar PV into the REZ.

The main difference with the European cases of internal transmission constraints is that the REZ export limit can, within certain limits, be tailored to the expected capacity of the REZ. As a standalone merchant entity the REZ can more readily adopt access rules that address curtailment more efficiently than the type of wholesale market designs prevalent in Europe and Australia. While storage can (and increasingly does) mitigate curtailment, beyond some level it is more costly to provide extra storage than the value of curtailed energy saved.[11]

VRE in a typical Queensland REZ has a peak:average output of about 3:1, so to achieve an acceptable average output within the REZ, entry will occur until it is almost inevitable that output in some hours will exceed export capacity and will be curtailed. The way in which VRE is then curtailed, and its rights to congestion revenue under LMP, can affect whether entry is efficient or over-encouraged (which, if desired, should then be an explicit choice). This article also compares different access and pricing regimes as they affect entry incentives into other constrained VRE export zones.

2. The model

The model is the simplest version to illustrate the problem. The VRE is located in a constrained subset of the network with no other dispatchable generation or flexible demand.[12] For convenience, this constrained zone will be called a REZ. The REZ is assumed to have no internal network constraints and is connected to the rest of the interconnected system through a single link. Problems of connecting different REZs through a constrained meshed network are beyond the scope of this model but will clearly be increasingly important as VRE penetration grows but that will be left for possible future work. Outside the REZ all market failures are assumed away or internalized, so that external market prices are efficient and correctly measure social value. There are constant returns to building VRE, and the annualized unit cost of VRE capacity (including any fixed O&M costs) is r_V \$/MW/yr. Avoidable costs are assumed zero. The capacity of the export link is K, the loss-adjusted price immediately outside the REZ is assumed constant at p and independent of REZ output.[13]

VRE capacity is $V > K$, and potential output at fraction of the year y is $\phi_y V$. It is convenient to order hours of production such that the capacity factor ϕ_y is decreasing in y as in Fig. 2. The curtailment function $k(V,K,y) = \phi_y V - K$ is defined for y such that $\phi_y V \geq K$, and will be similarly ranked so that $k(V,y)$ is decreasing in y up to y^* (the hour of highest VRE is also the hour of maximum curtailment) so that

$$k(V,K,y) = \max(\phi_y V - K, 0), \quad k(V,K,y^*) = 0. \tag{1}$$

Periods of zero curtailment are distinguished by $y > y^*$, with $y < y^*$ curtailed (see Fig. 3). Under efficient pricing (e.g. LMP) the REZ internal prices would fall to zero when output is curtailed, but would be p under current European and Australian National Electricity Market (NEM) market arrangements. As y is measured in fractions of the year, output will be measured in MWyears of 8760 MWhs. The average load factor, ALF, is then ϕ:

$$\phi = \int_0^1 \phi_y dy.$$

In Fig. 2 the ratio of peak output (ignoring the top $\frac{1}{4}$ of 1% or the top 22 h to rule out extremes that vary from year to year) to the average is 3:1, which the linearized duration curve in Fig. 3 can replicate. Marginal curtailment, MC, caused by the entry of 1 MW of extra VRE capacity, is, after setting $k(V,K,y^*) = 0$ from (1),

$$\begin{aligned} MC(V,K) &= \frac{d}{dV}\int_0^{y^*} k(V,K,y)dy = k(V,K,y^*)\frac{dy^*}{dV} \\ &\quad + \int_0^{y^*} \frac{dk(V,K,y)}{dV}dy \\ &= \int_0^{y^*} \frac{dk}{dV}dy = \int_0^{y^*} \phi_y dy \end{aligned} \tag{2}$$

Average curtailment, AC, is:

$$AC(V,K) = \frac{1}{V}\int_0^{y^*} k(V,y)dy = \int_0^{y^*} \phi_y dy - \frac{Ky^*}{V} = MC(V,K) - \frac{Ky^*}{V} \tag{3}$$

For fixed K, both the marginal curtailment MC and the average curtailment AC are increasing as the total installed volume of VRE V increases. The ratio of the marginal curtailment to average curtailment is greater than one for all values of $V > K$:

$$\frac{MC}{AC} = V\int_0^{y*} \frac{dk}{dV}dy / \int_0^{y*} kdy > 1, \tag{4}$$

This ratio is typically above 3 at modest levels of curtailment. Fig. 3 illustrates this geometrically and assumes that, in a modest size REZ, increments of VRE increase each point on the duration curve proportionately. As such it represents a more realistic simplification than assuming the curtailment curve is shifted vertically as in Newbery (2021). The VRE duration curve of Fig. 2 has been linearized to preserve the key feature that the curve is steeper for higher levels of output than lower (and could, if necessary, have additional linear segments without altering the argument).

The duration curve in Fig. 3 takes the form

$$\phi_y V = \max(V(1-ay)), (V(1-y)/a), \quad a > 1. \tag{5}$$

The Appendix gives the algebraic derivation of the resulting curtailment function as

$$k(V,y) = V - V_0 - aVy, \; K = V_0, \quad y^* = (1 - V_0/V)/a,$$

and derives the AC and MC for this case. Its piece-wise linear form allows a simple geometric interpretation. In Fig. 3 the average output is the area under the duration schedule ADF0, which is the sum of the two triangles AE0 and DEF. By simple geometry their areas are $\frac{1}{2}V/a + \frac{1}{2}V(1-1/a)/(1+a) = V/(1+a)$. Peak output is V so the peak:average is $1/(1+a)$. Thus if $a = 2$, the peak:average = 3 as in Fig. 2. Fig. 3 also shows the export capacity $K = V_0$ at C, with the

[11] Batteries suffer rapidly decreasing marginal revenues as successive MWh of storage are called on less and less.

[12] As such the model is applicable to more isolated regions with few sources of flexibility. Flottmann et al. (2022), Gilmore et al. (2023), Tigas et al. (2015) and Wang et al. (2021) discuss the options available to absorb excess VRE generation, but all conclude that beyond some point VRE will need to be curtailed.

[13] In Simshauser and Newbery (2023) prices vary hourly and can fall to zero if there is excess supply outside the REZ. If VRE output impacts the external market-wide price p and consumer demand is inelastic in the short run, then the fall in price will involve a one-for-one transfer from VRE to consumers, and will net out of total social surplus, but the fall in the market-wide price will have a slight negative effect on merchant profits. Using the regression results of Gonçalves and Menezes (2022) the impact of the Queensland REZ on market prices is very small — the 5-year average spot price reduces by about \$0.30/MWh/GW (primarily wind, solar PV has an insignificant impact at the observed, low levels of penetration) and does not affect the optimal choice of VRE to install.

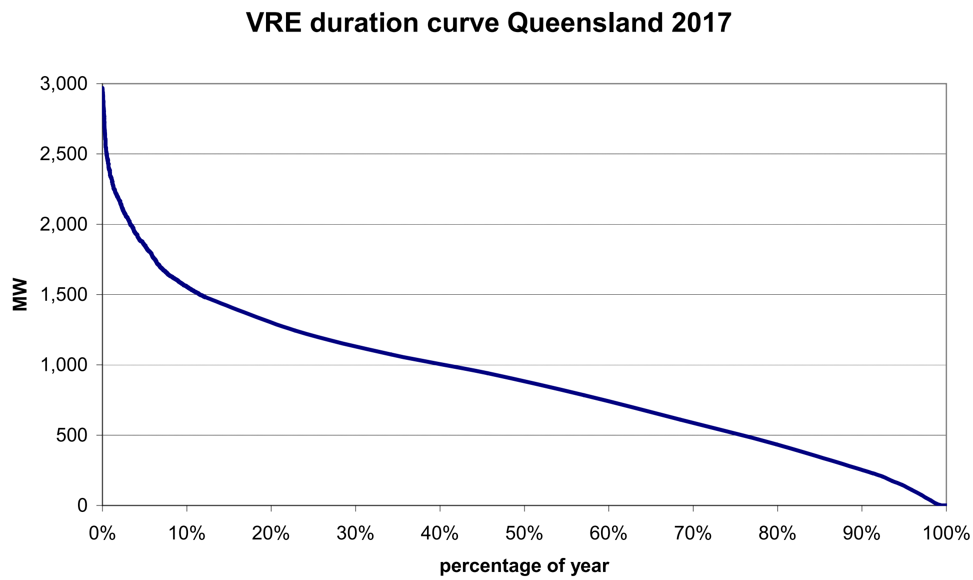

Fig. 2. VRE duration curve for Western Downs, Queensland, 2017.

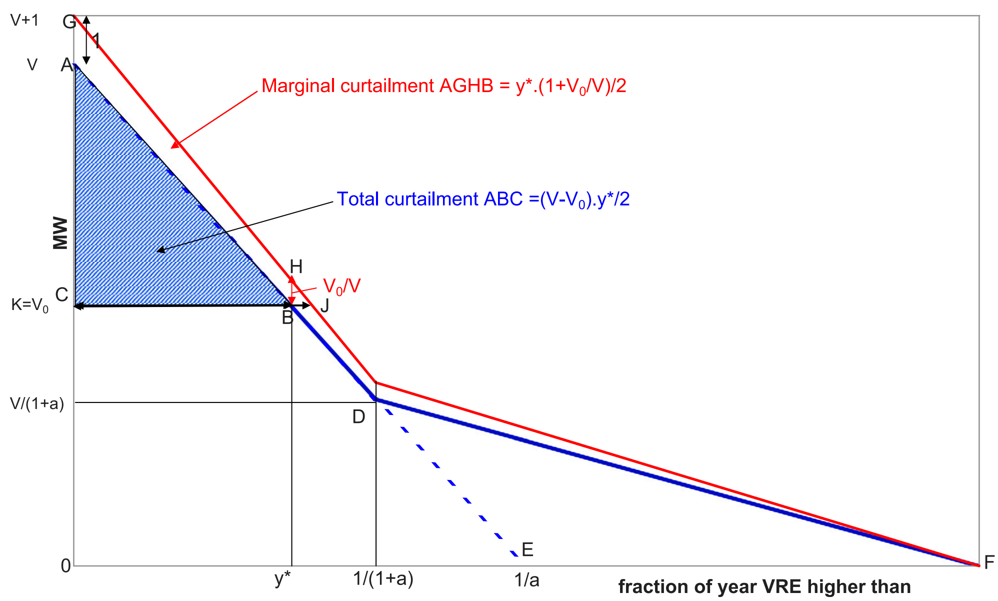

Fig. 3. Geometric illustration of average and marginal curtailment.

linear curtailment function AB and total curtailment the triangle ABC. As noted, increasing VRE scales up each point proportionately both for the duration curve and also the curtailment function. The figure shows that a 1 MW increase in VRE moves the curtailment function from AB to GH. Total curtailment is the area ABC = $\frac{1}{2}(V-V_0).y^*$ so AC = $\frac{1}{2}(V-V_0).y^*/V$. Marginal curtailment of the 1 MW entry is the area GABH,[14] MC = $\frac{1}{2}(1+V_0/V).y^*$, so MC/AC = $(V+V_0)/(V-V_0)$. Thus if $V=2V_0$, MC/AC = 3.

2.1. Efficiency conditions for the REZ

Consider a local REZ defined by export constraints in a region potentially attractive to VRE, and suppose that there are no other flexible generation or demand resources within the REZ nor any internal network constraints. Suppose hypothetically (and already a reality in countries like Australia, see Gohdes et al., 2022) that VRE investment is commercially viable without a long-term contract, so that we can consider subsidy-free merchant entry. Suppose also that the export constraint, K, has been pre-determined and cannot be relaxed in a reasonable time frame. Finally, and as a first step to be relaxed, that in common with most European systems, generation pays no charge for grid access, which is entirely paid for by load (i.e. off-take from the MITS).

The annual social value of the REZ is the value of the uncurtailed output (the area CBDF0 in Fig. 3, $\phi V - \int_0^{y^*} k(V,y)dy$), less its cost, Vr_V, less the cost of the link, which is a fixed cost of c per unit of capacity, cK. Consumers and producers (outside the REZ and connected to the MITS) experience no change in price p (assumed constant) and hence no change in surplus. The total social benefit of the REZ, W, is

$$W(V,K) = p[\phi V - \int_0^{y^*} k(V,K,y)dy] - Vr_V - cK. \quad (6)$$

[14] Plus the small triangle formed by extending the curtailment line CB and height BH, which in the limit is vanishingly small.

Efficiency requires that the choice of V and K is socially optimal. Social value is maximized at the capacity of VRE V^* and the capacity of transmission link K^* which satisfy:

$$\frac{\partial W}{\partial V}(V^*, K^*) = p(\phi - MC) - r_V = 0, \tag{7}$$

$$\text{and } \frac{\partial W}{\partial K}(V^*, K^*) = py^* - c = 0, \tag{8}$$

The following sections assess whether different access and pricing regimes achieve efficient entry signals and efficient incentives for sizing the connection.

2.2. Uniform pricing with pro-rata curtailment

After curtailment $\int_0^{y^*} k(V,K,y)dy$, total output will be $\phi V - \int_0^{y^*} k(V,K,y)dy$. If VRE continues to receive the market price p but is all uniformly (pro-rata) curtailed,[15] then the profit per unit of capacity of a marginal entrant facing no transmission charges is

$$\pi(V,K) = p[\phi - \frac{1}{V}\int_0^{y^*} k(V,K,y)dy] - r_V = p(\phi - AC) - r_V. \tag{9}$$

The free-entry equilibrium is here $\pi = 0$. Excess entry will occur if (9) less (7) is positive, which is the case as

$$p(MC - AC) > 0. \tag{10}$$

The strong conclusion is that market signals for entry are excessive if VRE continues to face external market prices, pays no transmission charges and is curtailed in proportion to capacity (i.e. pro-rata). If, as is also common at present, VRE has firm access (guaranteeing compensation if curtailed) the incentive to excess entry will be even greater.

Now consider the impact of imposing a transmission charge on VRE entrants in the REZ, at the rate cK/V^* per unit of capacity and assume that the transmission link is efficiently sized $K = K^*$ (so that $py^* = c$ when $V = V^*$). The profit per unit of capacity $\pi(V,K^*)$ is decreasing in V and has a unique zero at:

$$\pi(V^*,K^*) = p(\phi - AC) - r_V - \frac{cK^*}{V^*} = p(\phi - MC) - r_V + \frac{pK^*y^*}{V^*} - \frac{cK^*}{V^*}$$
$$= p(\phi - MC) - r_V = 0 \tag{11}$$

This is the same condition as Eq. (7) so the transmission charge restores the incentives for efficient entry in this case. We can conclude that, even under regional/zonal pricing arrangements, under the assumptions set out here, VRE entry into an isolated REZ is efficiently incentivized provided it is charged the efficient transmission fee for the connection to the MITS.

2.3. Non-firm access and priority dispatch

In the Single Electricity Market (SEM) of the island of Ireland, faced with an growing problem of curtailment and the difficulty of building transmission to resource-rich areas sufficiently quickly, Eirgrid (the SEM Transmission Owner) has proposed offering non-firm access to new entrants.[16] Existing VRE will be allowed to produce as before but new VRE entrants will be curtailed in a last-in first-curtailed basis, which is effectively curtailing them according to marginal, not average, curtailment. This should make the market entry condition $p(\phi{-}\text{MC}) - r_V = 0$ and so identical to the social optimum (7). Thus non-firm access rights and priority dispatch should restore efficient VRE entry signals, at least in the context of the assumptions we have made here (namely, only VRE generation in the REZ with uniform avoidable costs). Note that this result applies to VRE entry, and not necessarily to dispatchable capacity, where it may be desirable to encourage entry of more flexible plant, or plant offering system stability resources, which may be more valuable behind the export constraint than existing plant. Clearly such plant can be exempted from the priority dispatch rule as could VRE generators that offer similar flexibility options.

2.4. Locational marginal pricing

Under LMP, prices in the REZ fall to zero whenever the export constraint binds. In that case total output, Y, revenue, R, (ignoring any congestion rent if REZ prices fall to zero), and the profit $\pi(V,K)$ of an entrant (all per unit of capacity), will be :

$$Y = \phi V - \int_0^{y^*} k(V,K,y)dy,$$
$$R = pV\int_{y^*}^1 \phi_y dy = pY - pKy^* = pV(\phi - \int_0^{y^*} \phi_y dy),$$
$$\pi(K,V) = p(\phi - \int_0^{y^*} \phi_y dy) - r_V = p(\phi - MC) - r_V \tag{12}$$

The curtailed output during this period is Ky^*, so the volume that receives a positive price is equal to the potential output, ϕV less the zero price volume $\int_0^{y^*} \phi_y$.

Suppose that transmission link is efficiently sized. Entry will occur to the point where $\pi(V,K^*) = 0$. By Eq. (12), this is the same condition as Eq. (7). In other words, LMP (with an efficiently-sized link, no transmission charges, no allocation of the congestion rents) leads to efficient incentives for entry. Note that the beneficial incentives under LMP would be lost if incumbents in constrained regions could successfully claim compensation for the loss of revenue. If so, pKy^* will be returned to the VRE and will return them to the original inefficient entry condition (9).

3. Conclusion and policy implications

Most current VRE support policies exacerbate the inefficient dispatch of VRE. Network charging arrangements frequently fail to provide good locational guidance and, if generators are paid a regional price rather than the local price, the access arrangements can encourage excessive entry into export-constrained zones — and not just for VRE. As many authors have noted, these design flaws call for immediate reform of either transmission pricing and/or locational marginal pricing. While the concept of average curtailment is well recognized and even that curtailment can rise rapidly with increased penetration, the concept of marginal curtailment has been underappreciated and brings new challenges to market and access design. As marginal curtailment is typically 3+ times as large as average curtailment and as balancing actions normally treat all VRE equally and thus result in average curtailment, VRE entry decisions will be based on average curtailment and could be inefficient without appropriate market and access design.

This article has developed a simple but robust model to examine these issues for resource rich regions facing a single transmission constraint for exporting VRE. Even under ideal conditions in which merchant entry is commercially viable with no long-term contracts distorting dispatch decisions (e.g. by paying only on metred output) there are problems with most current market designs. Thus merchant VRE entry incentives are excessive in most liberalized European electricity markets with country-wide or regional zonal pricing where there are binding intra-zonal constraints, zero transmission charges and firm access (i.e. the right to compensation if curtailed).

[15] This is true for the leading example of Queensland REZs, and would be open to developer-managed REZs such as off-shore wind parks, but is strongly opposed in EU Regulation (EU) 2019/943 Article 13 (https://www.legislation.gov.uk/eur/2019/943/article/13/adopted) which requires non-discriminatory redispatching of all generation and demand “using market-based mechanisms and shall be financially compensated”. Whether this is sensible is one of the issues discussed in the modelling below.

[16] Eirgrid (2022). The proposal is to move to firm access when the transmission constraint is removed or after five years, whichever is sooner.

Modest changes to the access regime for new VRE entrants into an REZ granting them non-firm access and priority dispatch (last in, first curtailed) mitigate the problem while not disturbing revenue streams to VRE incumbents, under the assumption that all VRE entrants have the same (or similarly low) avoidable costs and that entrants cannot incur additional costs to rush entry to obtain priority dispatch.[17] In systems with zonal pricing, such as the Australian NEM, if exit capacity is optimized and VRE pays the marginal exit capacity charge, then entry signals would be efficient even under current state-wide pricing, at least assuming that all units have the same (zero) avoidable costs.[18] Indeed, priority access would both be unnecessary and give inefficient signals. If Australia adopted LMP, then if VRE is charged for transmission, efficient entry signals would require pro-rata allocation of Transmission Congestion Revenue contracts. A simpler solution would be to remove the transmission charge and allocate all congestion revenue to the transmission owner.

The main conclusion is that transmission charging, access regimes and market pricing rules all interact to determine the efficiency of entry signals facing new VRE investors, most importantly in existing networks with a variety of possible location options. While this article has shown that LMP requires natural adjustments to the access regime as far as VRE is concerned, it is not an argument against LMP. On the contrary, the main attraction of LMP is its ability to give efficient real-time dispatch signals for all forms of generation and load, including technologies not yet invented. Discussions about the case for LMP (e.g. Ofgem, 2023) note that contracts for supporting VRE would probably need modification, and this article has shown that a move to LMP could require revisiting existing charging and access rules.

CRediT authorship contribution statement

David M. Newbery: Writing – review & editing, Writing – original draft, Visualization, Methodology, Formal analysis, Data curation, Conceptualization. **Darryl R. Biggar:** Writing – review & editing, Validation, Methodology, Formal analysis.

Declaration of competing interest

None.

Data availability

No data was used for the research described in the article.

Appendix A. Linearizing curtailment functions

The general symmetric VRE duration schedule in Fig. 2 is

$$\phi_y = \max((1-ay),(1-y)/a), \quad a>1.$$

The ratio of peak to average output is $1+a$. Fig. 2 also shows the export capacity $K=\phi V_0$ at C, with the linear curtailment function AB and total curtailment the triangle ABC. The curtailment function is

$$\begin{aligned}
k(V,y) &= \phi_y V - K = V(1-ay) - K, \ \ y \le y^*, \\
V_0 &= V(1-ay^*) = K, \ \ \text{if } y^* < 1/(1+a), \\
y^* &= (1-V_0/V)/a, \ \ dy^*/dV = V_0/(aV^2), \\
k(V,y) &= aV(y^*-y) = V - V_0 - aVy, \ \ y \le y^*.
\end{aligned}$$

[17] Priority dispatch would not necessarily be efficient for dispatchable generation offering required system services within the constrained zone.

[18] Merit order effects caused by different VRE having different avoidable costs could introduce small inefficiencies if all are curtailed equally, but the low average curtailment rate and the low avoidable costs would make this inefficiency very small.

Average curtailment is

$$AC = \frac{aV}{V}\int_0^{y^*}(y^*-y)dy = \frac{a}{2}(y^*)^2 = \frac{(V-V_0)^2}{2aV^2}.$$

Marginal curtailment is

$$\begin{aligned}
\int_0^{y^*}\frac{dk}{dV} &= \int_0^{y^*}\left(\frac{\partial k}{\partial V}+\frac{\partial k}{\partial y^*}\frac{dy^*}{\partial V}\right)dy, \\
&= \int_0^{y^*}\left(a(y^*-y)+aV.\frac{1}{a}\frac{V_0}{V^2}\right)dy, \\
AC &= \frac{a}{2}(y^*)^2+\frac{V_0}{V}y^* = \frac{V^2-V_0^2}{2aV^2}.
\end{aligned}$$

The ratio of MC/AC is

$$\begin{aligned}
\text{MC/AC} &= \frac{V^2-V_0^2}{(V-V_0)^2}, \\
&= \frac{V+V_0}{V-V_0},
\end{aligned}$$

as in the second case above.

In addition

$$\begin{aligned}
\frac{1}{V}\int_0^{y^*}\phi_y dy &= \int_0^{y^*}(1-ay)dy \\
&= y^*(1-\frac{1}{2}ay^*) \\
&= y^*(\frac{V+V_0}{2V}).
\end{aligned}$$

Appendix B. Acronyms

AC: Average curtailment; AEMO: Australian Electricity Market Operator; GB: Great Britain; ERCOT: Electric Reliability Council of Texas; FERC: Federal Energy Regulatory Commission; JRC: Joint Research Centre; LMP: Locational marginal price; MC: Marginal curtailment; MITS: Main interconnected transmission system; NEM: National Electricity Market (of Australia); O&M: Operation and maintenance; PJM: Pennsylvania-New Jersey Maryland; REMA: Review of Electricity Market Arrangements; REZ: Renewable Energy Zone; RHS: Right hand side (of graph); SEM: Single Electricity Market of the island of Ireland; TNUoS: Transmission Network Use of System; TO: Transmission Owner; VRE: variable renewable electricity (i.e. wind and solar PV).

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