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Abstract

Data Centres make huge demands on uninterruptible power. Large increases in Variable Renewable Electricity (VRE), often located distant from demand and congesting existing transmission, signal the benefits of locating data centres behind the congested export lines but may suffer from increased isolation from customers. Without efficient signals (or central location planning) the mismatch between locating VRE and data centres is exacerbated. The article examines various solutions to this potential market failure, from transmission pricing reform, zonal pricing and energy price discounts in export-constrained zones.

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1. Introduction

Two megatrends are emerging – one global, that of the growth of Variable Renewable Electricity (VRE, wind and solar PV), the other initially confined to developed market economies in North America, Europe and China, that of rapidly growing power-hungry data centres. VRE expanded by 16% globally in 2025 (IEA, 2026), while McKinsey (2025) projects an annual global growth rate for data centres of 22%. For the US the figure is 66% c.a.g. from 2025-27,² while the UK anticipates a quadrupling of data centre electricity demand by 2030 to perhaps 6.3 GW, or 32% c.a.g. although at present their consumption is only 2.5% of total demand (House of Commons Library, 2026). While this might seem a happy congruence of demand and supply growth, the country-wide average growth rates ignore important spatial disparities – wind is typically located far from demand centres while data centres prefer to cluster round major conurbations, as a recent map of Britain shows.³

Britain provides an excellent case study of the logic of locating data centres in high wind surplus regions. Surplus Scottish wind is a problem looking for a less costly solution than the proposed transmission investments while central data centres struggle to secure connection agreements (CBRE, 2026, p18). Locating data centres in Scotland would increase local demand and reduce the surplus that needs to be exported across the currently congested border with England. This would not only be quicker than building much-needed new

¹ I am indebted to a very helpful referee for urging greater clarity and David Reiner for noting an important missing phrase.

² <https://www.goldmansachs.com/insights/articles/us-data-center-power-demand-projected-to-double-by-2027>

³ <https://www.bbc.co.uk/news/articles/clyr9nx0jrzo>

transmission but much cheaper, provided there are suitable locational signals to guide data centre location.

This paper compares the various policy options for reconciling these megatrends in Britain and deriving efficient locational signals for data centres. Locational pricing would make wind-surplus Scotland a cheaper source of electricity than London, but has been ruled out by the UK Government (HMG, 2025a). Efficient transmission charging would discourage further wind investment in Scotland and make data centre connections cheaper there than in urban centres south of the border but the current charges give inadequate incentives. The regulator, Ofgem, has consulted on alternatives to locational wholesale pricing including reforming locational transmission charging that this paper argues is the best solution (Ofgem, 2026). Finally, the UK Government's AI data centre policy is pursuing an active location initiative targeting data centre energy subsidies in northern locations (HMG, 2025b, §3) but again with inadequate incentives to reduce exports when congestion binds. This paper compares and evaluates these three options for Britain, although the comparisons have broader significance.

VRE in distant locations is increasingly curtailed (i.e. wasted) unless transmission is expanded – typically a costly and time-consuming process (Bird et al., 2015; Eirgrid, 2026; Newbery, 2021, 2026; O'Shaughnessy et al., 2020; Savelli, et al., 2022). Data centres find it increasingly difficult to secure adequate transmission access and raise concerns over generation adequacy, given their greater demand growth compared to local electricity supply growth, most notably in Dublin.⁴ The US is probably the leading case, where data centres individually have such large demands that they struggle to secure transmission access, resulting in phantom queues (hoping one will secure access), higher local prices (creating strong local opposition) and the requirement to provide self-generation.⁵

Sweden has zonal prices which have diverged since 2020, with lower prices in northern zones (SE1 and SE2) but price differences are sensitive to zonal export opportunities, nuclear power decommissioning and fluctuating growth in wind power (Bălașa and Pollitt, 2026). Sweden had 122 data centres but only 12 in SE1 and SE2,⁶ suggesting that zonal price differences are not in themselves powerful determinants of data centre location. One obvious reason is that zonal prices are set in spot markets and their future values will depend on transmission and generation investment, both hard to predict and hedge for more than short periods (Adamson and Pollitt, 2026). A more fundamental objection is that zonal price differences under-state the marginal cost of increasing transmission capacity between zones and hence understate the marginal cost of injecting or absorbing power from distant zones (Perez-Arriaga et al., 1995).

2. A case study: reforming transmission pricing in Britain

Great Britain, GB, is unusual in Europe in having quite highly spatially differentiated Transmission Network Use of System (TNUoS) charges. ENTSO-E reports that only the UK and Ireland differentiate transmission charges by location, although Norway charges marginal

⁴ <https://buildermuse.com/infrastructure/dublin-data-center-power-moratorium/>

⁵ <https://stateimpactcenter.org/insights/data-centers-straining-the-grid-and-your-wallet>

⁶ <https://www.datacentermap.com/sweden/>

loss factors in addition to zonal pricing (ENTSO-E, 2025). As zonal pricing has been ruled out, the main instrument guiding GB location investment decisions is the locational TNUoS charges. These charges are intended to be Long Run Incremental Costs, LRICs, derived by calculating the cost of building transmission lines needed to deliver power from the injection point to delivery points, as set of in the *Charging Methodologies* of NESO (2025c). More precisely, the calculations assume that existing overhead high voltage lines can be instantly expanded to deliver an extra MW from the injection point, although this is clearly a fiction as building more lines at present is very difficult, as discussed below, and at present can take 7-14 years (Winser, 2023).

The annual charge is per kW of Transmission Entry Capacity (TEC) adjusted for capacity factors and for the stress the type of generator places on peak supply. Charges vary considerably across the country, high in Scotland, and low (negative) charges in London and lower still in the Cornish peninsular (far south-west). The reason for negative charges (payment for the amount delivered in winter peak half hours) is that the average across all generation must be less than €2.50/MWh to ensure efficient trading with neighbouring countries. For 2025-26 the range of charges across the country for wind farms with a 40% capacity factor (CF) was £36.56/kW per year, i.e. £36,566/MW per year or £9.80/MWh (NESO, 2025a). Perhaps a more useful comparison is between a wind farm operating in windy Argyll in SW Scotland with the highest G-TNUoS charge⁷ and one in East Anglia, where the difference is £28.21/kWyr or £8.05/MWh. If the East Anglian wind farm cannot rely on delivering power during the peak winter hours (when generators are paid to deliver), then the difference would increase slightly to £8.56/MWh (again assuming a 40% CF in both locations). This difference is material compared to the February 2026 Auction Round 7a for 20-year contracts for onshore wind that set the strike price at £72.24/MWh.⁸

Scotland is projecting rapid growth in wind capacity from 10.4 GW in early 2025 to 20 GW by 2030.⁹ However, congestion on the transmission (B6) boundary from Scotland to England already seriously limits wind exports to England. In 2024-25 the National Energy System Operator (NESO) had to curtail 13% of potential wind output, almost entirely in Scotland, because of congestion (9.3 TWh of a potential 71.8 TWh) up from 8% the previous year (NESO, 2025b, p13). The rapid growth in constrained output reflects the demonstration that the marginal curtailment is typically 3+ times average curtailment (Newbery, 2021, 2023), and so will accelerate unless transmission is expanded. Green and Newbery (2026, fig. 6) showed that a considerable share of that lost output came from recently commissioned Scottish wind farms that were constrained-off more than 50% of their potential output, confirming this prediction.

⁷ The G-TNUoS charge for Argyll is the sum of the System Peak charge of £3.58, the shared year-round charge of £16.94 which as it is shared is multiplied by the Average Capacity Factor (40% in this case), the non-shared year-round charge of £21.39 (all of which vary by zone) and the residual charge of £-1.75 (equal for all zones), all per kW of TEC per year. The residual is set to ensure that the average generation charge is set at €2.50/MWh to comply with ENTSO-E rules for trading with neighbouring countries on equal terms. Negative G-TNUoS charges are paid on the amount delivered in the three Triad periods of peak demand separated by 10 days.

⁸ <https://assets.publishing.service.gov.uk/media/698a0dc06da2dee8230a9c3a/contracts-for-difference-AR7a.pdf>

⁹ <https://www.sdi.co.uk/news-and-success-stories/success-stories/scotland-s-onshore-wind>

In response to this rapidly increasing congestion and the high cost of constraining-off wind farms and constraining-on replacement gas generation, NESO, the recently created public company responsible for strategic planning and energy system operations, published its *Beyond 2030* report, recommending around £64 billion in direct investment for offshore and onshore network upgrades (NESO, 2026, p30). The revised cost has since increased to £89 billion, partly due to inflation, partly from increased forecast demand with the need for more capacity.¹⁰

The *Report* includes a number of subsea HVDC links (now six, shown in Newbery, 2026b, Fig. 2) that could carry power from Scotland to England, but these are 5-10 times as costly as onshore HVAC lines between the same points (Newbery, 2026a, Table 1). If it did prove impossible to build onshore lines (e.g. by building lines on the same routes as existing lines that were approved in the past), then the cost of transporting wind from Scotland to load centres in England could be as high as £89,264/MWyr or £25.47/MWh at 40% CF, almost prohibitively high (Newbery, 2026a, p8).

3. Locating data centres in Scotland

Data centres typically have an almost continuous load, in some cases with higher demands for cooling in the day than night and, with the right combination of wind and solar PV, better match VRE supply patterns (Arthur D Little, 2023, fig 2). Large data centres (above 50MW in England, above 10 MW in Scotland) are connected to the Main Interconnected Transmission System (MITS), as are large wind farms – in both cases smaller units are connected to the local distribution network that has different charging rules. The calculation of the charges for load are complex (NESO, 2025c), but for current purposes the relevant part is those that vary by location.¹¹ L-TNUoS charges are charged according to the demand taken over the three Triad periods each year, defined as the three half-hours with the highest net system demand, between November and February (inclusive), separated by at least ten clear days.¹² Because Generation G-TNUoS charges are constrained by the requirement that the average is no more than €2.50/MWh, Load L-TNUoS charges need to be considerably higher on average to collect the allowed regulated revenue. In addition, where G-TNUoS charges are high the benefits of local demand are also high to reduce demands on the MITS. L-TNUoS charges are low (potentially negative to preserve a stable difference between G- and L-TNUoS charges) in excess supply areas and high in excess demand areas. Their average level is raised to deliver the required revenue. In principle, the charges should be raised by a uniform amount just as the G-TNUoS charges were all reduced by the same amount to preserve the desired spatial range of charges. Before the adjustments discussed below the range of charges from highest to lowest is £44.79/kVAyr but after adjustment only £10.12/kVAyr.¹³

¹⁰ <https://www.theguardian.com/business/2026/jun/30/great-britain-electricity-network-90bn-pounds-2030s>

¹¹ In addition, Loads pay £26/kVAyr for Maximum Import Capacity but this does not vary spatially.

¹² <https://www.neso.energy/document/130271/download>

¹³ kW is kilowatts, real power, while kVA is kilovolt amperes, apparent power, combining real power and reactive power.

3.1. Reforming transmission charges

The logic of setting TNUoS charges would suggest that where G-TNUoS charges are high (as in Scotland) Load or L-TNUoS charges should be negative, but instead they are collared at zero (NESO, 2025c, §14.15.141) with the remaining positive charges scaled to collect the required revenue. This has the perverse effect of relatively discouraging large mobile loads like data centres from locating where there is surplus VRE. Thus, for Northern Scotland were the L-TNUoS charge not collared at zero, the charge would be **-£34.67/kWyr**, or for a large load connected to the MITS with a 100% load factor, **-£3.97/MWh**. However, firm demand (of the kind that high load factor data centres can provide) reduce the demand made on the constrained B6 export boundary at the Scottish-England border with the potential to reduce the need to reinforce Scottish export capability.

Export capacity at the B6 boundary is forecast to increase as new links are commissioned. From the thermal limit of 6,683 MW in 2026, under all NESO's scenarios for future Scottish capacity, the limit rises to 9,610 MW in 2027, to 11,456 MW in 2029 and to 15,354 MW in 2030,¹⁴ presumably as a result of commissioning the sequence of new subsea Scottish-England Green Links starting with SEGL1 and SEGL2, each of 2 GW nominal capacity. Figure 1 gives an indication of a possible 2030 wind scenario, before and after netting out Scottish demand (ignoring storage and possible other high demands such as hydrogen generation and data centres) and after adjusting for self-curtailment where wind farms choose a lower TEC than their potential maximum output, as the cost of the extra TEC is higher than the value of the extra wind that could be produced in the small number of hours of maximum output (Newbery, 2026a).

When data centres locate in Scotland, they can make use of this surplus generation and reduce the need to build additional transmission. As data centres have high load factors, they increase demand by their rated capacity almost all the time and so shift the net surplus down in figure 1 by that amount.¹⁵ Thus 2.2 GW of data centre demand would avoid the need to build one of the SEGL subsea links (each of nominal 2 GW capacity). Newbery (2026a Table 1) gives the annual cost of moving power from Scotland to the Midlands (chosen as each link connects to different zones south of B6). If the two SEGLs are built to budget, SEGL1 would cost £83,500/MWyr and SEGL2 £131,370/MWyr (2023 prices). For a data centre displacing SEGL2 requiring firm demand 24/7 this would amount to £15/MWh. That could avoid building SEGL2 and save 2000 x £131,370/MWyr or £263 million/yr.

¹⁴ <https://www.neso.energy/publications/electricity-ten-year-statement-etys/electricity-transmission-network-requirements/scottish-boundaries>

¹⁵ Some data centres can offer fast frequency response to the balancing market but this is unlikely to be called on when the export constraints are binding (the relevant case here).

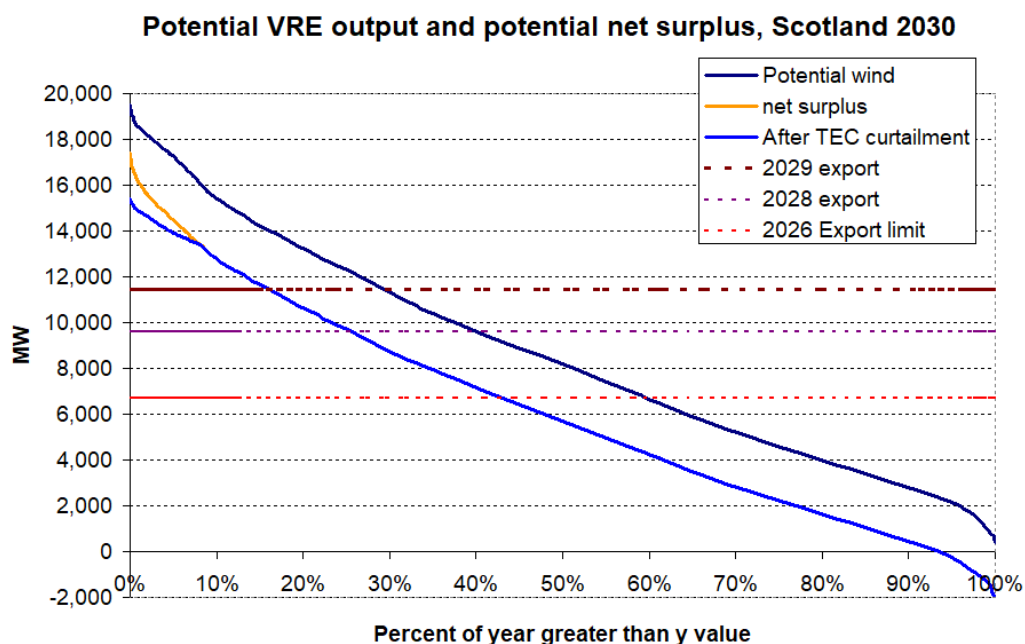


Figure 1 Potential gross and net Scottish VRE output, 2030

Source: Newbery and Chyong (2025)

Notes: Potential output and demand are for all of Scotland (North and South) from the source, voluntary curtailment is taken as 13% of peak VRE demand from Newbery (2026a Table 2), an overestimate as this includes PV (not curtailed but rarely contributing to peak VRE output) and aggregates all wind as though it were a single wind farm, ignoring the smoothing impact of imperfectly correlated wind outputs. Potential wind and net surplus are independently sorted in decreasing order – points at the same x value are not the same hour. Export limits are at the B6 boundary and ignore the 450 MW Moyle link to N Ireland and internal network constraints.

The practical question is how best to reflect this notional negative L-TNUoS charge with NESO's judgement that load should not be paid to connect and consume whenever they like. In contrast the G-TNUoS negative charges come with an obligation to deliver in peak hours. Flexible load can bid to increase demand in the balancing market to reduce the need to constrain-down generators behind a constraint, but this is not an option for data centres. Instead, they could sign a contract that if they are operating at full load during periods in which the export constraint binds, they would be compensated with the balancing price. If that is too unpredictable, the amount could be pre-determined and included in a five-year contract, easing the pressure on building extra transmission.

3.2. Existing AI locational policy

The UK Government has published its policy paper *Delivering AI Growth Zones* noting that if data centres locate in Scotland they could reduce VRE constraint costs, and if they did so “they will receive a *commensurate discount* on electricity costs. ... From April 2027, subject to legislative timetables, data centres in AI Growth Zones will see a reduction in electricity costs of up to £24/MWh in Scotland ...” (HMG, 2025 §3, emphasis added). This could be larger than the £15/MWh avoided cost of building SEGL2 (but note the qualification of “up to”).

On the other hand, if NESO, perhaps under Government pressure to minimise the costs of decarbonising the electricity system, were to abandon subsea links and instead build onshore lines along the same wayleaves as the existing north south backbone transmission lines or the cheaper and less visually intrusive HVDC lines on the same routes (Newbery, 2026b), the avoided cost would be considerably lower. Using the later 2025-26 G-TNUoS charges (NESO, 2025a) the charge from Argyll to the Midlands for 100% CF is £40,970/MWyr or £4.68/MWh (at 2025/6 prices).¹⁶ The benefit of locating data centres in Scotland would be comparable to this figure, below the proposed maximum discount.

One drawback of this locational electricity discount is that it provides no incentive to operate at full load when exports are constrained, as offering to increase output in the balancing market runs counter to operating at high load factors. Perhaps the discount should be conditional on importing at some specified fraction of Maximum Import Capacity. The more important incentive proposed is the speed of agreeing a Scottish connection given connection delays in major English cities.

3.3. Zonal pricing

Chyong and Newbery (2025) modelled GB VRE in one of NESO’s 2030 *Future Energy Scenario*, (*FES*, ESO, 2024), allowing for transmission constraints and inertial requirements. With no transmission investment after 2024 but with the projected *FES* 2030 VRE capacity in Scotland, potential VRE output there would be 75.7 TWh and curtailment would be 13.9 TWh, with curtailment at the B6 boundary for 2,901 hours (33% of the year).¹⁷ If all the proposed transmission investment in the *FES* were achieved by 2030, curtailment would fall to 7.6 TWh over 1,683 hours (14%), roughly consistent with where the boundary lines intersect net surplus in Figure 1.

With zonal pricing, wholesale prices in Scotland should fall to near zero whenever the B6 export constraint binds. The number of constrained hours may fall slightly as it ignores possible exports to N Ireland but high wind in Scotland usually follows high wind in N Ireland by about 3-4 hours, so by the time there is surplus wind in Scotland that export route may be saturated. Zonal pricing should give on average lower prices in Scotland than England, where at the time of writing the forward wholesale price for Winter 2026 was

¹⁶ The TNUoS charges have been substantially increased since 2023/24 on which the subsea comparisons were made, while uprating to 2025/26 prices with the CPI would augment them by 6%.

¹⁷ Curtailment within Scotland would actually be higher at 3,402 hours.

£144/MWh and for summer 2027 £97/MWh, or an average of £120/MWh.¹⁸ If the zonal price in Scotland were the same as in England when B6 is uncongested and otherwise zero the wholesale price advantage if exports were constrained 33% of the year would be £40/MWh, or at 14% of the time, £17/MWh (ignoring seasonality as wind is stronger in the winter). Combined with the L-TNUoS price difference even the lower value would exceed the proposed data farm subsidy of £24/MWh, although electricity prices are currently well above long-term averages because of the sharp increase in gas prices caused by the Iran-US conflict.

Chyong and Newbery (2025) made rough calculations of the system marginal cost (SMC) of electricity in each zone based on pre-conflict energy prices and found an average price difference between Scotland and London of £28/MWh if no B6 reinforcement took place, falling to £4.62/MWh after reinforcement, both at 2026 prices. These lower price differences reflect the expectation that England may also be in VRE surplus in the same hours, reducing the price difference. Average SMCs considerably underestimate average viable wholesale prices as they would fail to recover fixed costs (in GB partly covered by capacity payments of £60,000/MWyr or £6.85/MWh with National Pricing, higher with the lower average zonal pricing). The SMC also excludes the high balancing costs needed with national pricing that would further amplify these SMC differences. Zonal pricing could then give some locational guidance to data centres, but their susceptibility to transmission investments reduces their power as investment location signals.

4. Conclusions and policy implications

Efficient transmission charging (specifically based on the avoided cost of the most expensive reinforcement otherwise necessary) with suitable adjustments via payments for running contracted load in export hours to avoid negative charges is the most appropriate solution and consistent with the proposed reform of transmission pricing. Zonal pricing, combined with suitable transition contracts to overcome resistance from parties that stand to lose substantial balancing payments, might at some date become politically feasible, and would have other advantages for improving demand-side response, battery storage use, and better management of interconnector flows. However, future zonal price differences are hard to predict and typically understate the cost of the transmission needed to relax the price differences and hence the benefit of avoiding such investment.

Until these delayed desirable reforms take place and given the lengthy delays in expanding even on-shore transmission lines, the UK Government's proposed electricity subsidies in AI Growth Zones in Scotland could be an efficient stop-gap solution for base-load data centres that reduce congestion at the Scottish boundary, provided there is some incentive to operate near Maximum Import Capacity when the boundary is export-constrained. A possibly greater incentive to locate data centres in export constrained areas is the promise of a fast connection agreement when more desirable English locations have lengthy connection delays. The promise of the Government's *Delivering AI Growth Zones* of a locational discount/subsidy with a speedy connection is thus a simple solution to the complexity of market and transmission price reforms.

¹⁸ Contains BMRS data © Elexon Limited copyright and database right 2026. Chart: Catalyst Commercial Services, [catalyst-commercial.co.uk](https://www.catalyst-commercial.co.uk) at <https://www.catalyst-commercial.co.uk/wholesale-electricity-prices/> accessed 4/9/26

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