Energy Transition
Interdisciplinary Institute

Should Zonal Pricing be Introduced in the UK?

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Executive Summary

Redesigning the UK electricity system around local price has some logic and potential cost benefit for a subset of consumers. However, the reality of the policy upheaval, the practical delivery challenge of convincing other consumers to pay more and the uncertain benefits, would all risk the progress of the Energy Transition. Having investigated the data and evidence-base, we conclude that the benefits of zonal pricing are outweighed by the challenges in its implementation, runs the risk of deflecting attention away from more pressing issues and increases uncertainty to investment at a time when cost concerns are reducing confidence. Instead of introducing zonal pricing, we recommend that the UK Government uses existing locational cost signals in the market, provides a better mechanism for these costs to be accurately forecast and enables greater market participation of interconnectors, batteries and small-scale assets.

How did we get here?

The history of UK grid development was heavily influenced initially by local industrial demand and subsequently by growth of major conurbations and power-intensive industrial clusters through the 19th Century. Initially, transportation of electricity over long distances simply was not possible, therefore production and use were co-located as much as possible. Local grids, networks or zones developed independently to serve power-hungry cities and industrial clusters. Sometimes those networks were separated by geography or by some economic reason that meant the cost of electricity in one region was uncorrelated to that in a neighbouring region.

Realising the need for an organised power network, the Central Electricity Board was founded in 1926 and the first grid tower constructed near Edinburgh two years later. Rapid expansion saw semi-regional grids established by 1933 and a single, national system in place within five years, the value of which was readily apparent during the Second World War when generation in South Wales could power London after the powers stations at Battersea and Fulham were out of action.

Following the war, the industry was nationalised and a state-owned Government body, the Central Electricity Generating Board (CEGB) was created in 1958, an entity that remained in place until it was sold off and privatised in 1990.

The current position is that National Grid Electricity Transmission (NGET) own and maintain the high-voltage electricity transmission network in England and Wales connecting consumers to the electricity they need. Scottish Power Transmission (SPT) serve the same purpose as NGET in the South and Central Scotland as do Scottish and Southern Electric (SSE) in the North of Scotland.

The National Energy Systems Operator (NESO) manages the grid and as such, is independent, impartial voice to energy system planning and operations that takes this whole system view considering the trade offs and interrelated challenges that ensure optimal outcomes for consumers.

With the advent of High Voltage Direct Current ("HVDC") and cost reductions in the requisite transmission infrastructure, it became cheaper in the UK to transport electricity than to transport coal. In recent years, old carbon intensive coal-fired power stations closed in the south and generation capacity was replaced by those located nearer to coal mines in the East Midlands, northern England and Scotland such as Drax, Longannet and Cockenzie etc.

Investment in the Transmission infrastructure enabled more areas to be connected and incrementally over decades, the grid physically began to appear as we have today with the cost of electricity "balanced" across the country, in the same way the physical electrical characteristics are also shared.

The grid has successfully evolved from local to national and then from transitioned from coal to gas as production from the North Sea and other parts of the UK Continental Shelf (e.g. East Irish Sea) ramped up and the UK converted to gas for domestic heating, cooking and some of its power supplies.

The challenge today is the incorporation of an increasing share of renewables generation from wind and solar, much of which is generated a long way from point of use and therefore requires additional transmission investment, a situation that is not unique to the UK and is increasingly being shared around the world.

Renewables generation is intermittent by its very nature (i.e the sun doesn't always shine and the wind doesn't always blow), and as such, has very different characteristics to conventional fossil fuel-based systems. Renewables lack the ability to provide "mechanical inertia"; are unable to release or absorb fluctuations in energy to stabilise the grid at the right frequency, something that relies on other systems with a fast frequency response, battery storage and continued investment in transmission infrastructure.

Not having sufficient inertia across the system can leave electricity transmission vulnerable when the systems are stressed, trip out occurs and there is a need for a fast ramp up from baseload as demonstrated by recent events in Iberia. This is not a problem in itself, the solutions exist, but grid investment must keep pace with the continued development of renewables.

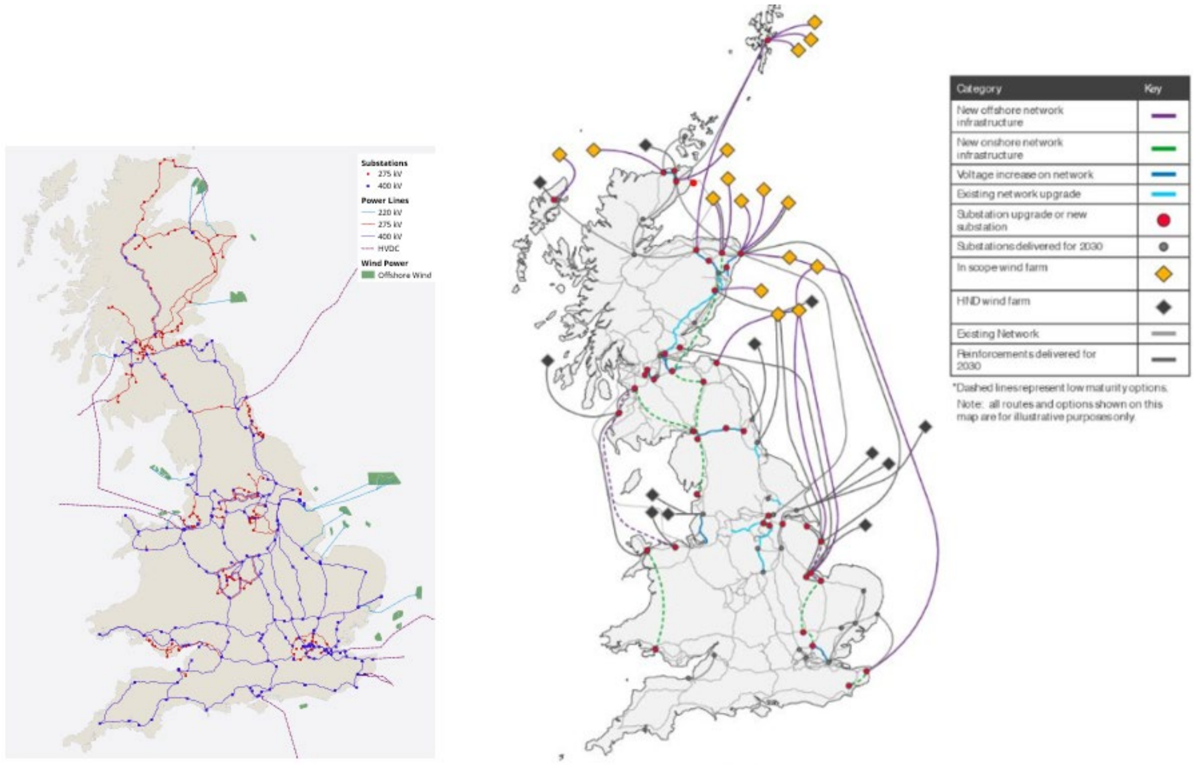
The design of onshore grid connections for largescale renewable energy projects is often designed with inertia in mind. Technical solutions such as the inclusion of synchronous condensers or static var compensators can provide "Reactive Power" and replicate the grid stability provided by spinning generators of gas turbines. However, this will make a wind farm grid connection more expensive and the requirement and specification is not standard for every project. Examples where synchronous condensers are necessary include the Galloper Offshore Wind Farm, which connects to the grid in Suffolk, a particularly congested region. By comparison, the Rampion 1 Offshore Wind project connects to the grid in mid-Sussex and does not require Synchronous Condensers. The point of connection, length of the onshore cable and other activity on the grid are all factors that need to determine the engineering design of a grid connection.

Where are we right now?

Operating at a frequency of 50HZ, mainland Britain's high voltage electricity power network is known as the National Grid and it connects power stations and substations across England, Scotland and Wales (but not Northern Ireland). The Grid consists of a series of 400kV, 275kV and

132kV power lines (Fig.1), the hubs for which are largely dictated by the locations of the original coal-fired power stations that were invariably linked to coal mining areas (examples of which include Longannet, Cockenzie, West Bridgford, Drax and Ratcliffe-upon-Stour), gas-fired power stations (e.g. St Fergus), nuclear power stations (e.g. Dounreay and Torness) and hydro-electric generators.

Onshore and some offshore wind sites have been added to the network in the past decade or so, but the aspiration is that more will be forthcoming to take the UK from its current 14.7GW to 50GW of generating capacity by 2030.



Source: National Energy System Operator

Figure 1: Maps of the current National Grid network of existing electricity sub-stations and power cables and the new design following the re-wiring to accommodate new clean power sources.

The UK mainland electricity grid is divided into three Transmission systems and eight Distribution systems (Fig.2)

Figure 2: Map of electricity distribution and transmission systems

[How do the UK's energy network works? - Energy Networks Association]()

Whilst the transmission networks are akin to the motorway trunk roads transporting electricity, the distribution network represents the B-roads that takes electricity to consumers homes and businesses.

Managing the electricity system for long transmission and short distribution and stepping up and down the voltage, to ensure the grid remains balanced and reliable is the responsibility of the system operator.

<u>What is zonal pricing?</u>

Zonal pricing is an electricity market design philosophy where the wholesale electricity **price** at different locations in Great Britain represents the value of energy for that location.

Its introduction would mean different electricity prices for UK consumers, depending on their location and number of zones.

In theory, zones where electricity generation is concentrated (including those in the aforementioned northern locations) that experience an excess of electricity supply over demand, with the consequent lower price on their bills.

In contrast, locations such as the large urban conurbations like London, Birmingham, Manchester, Leeds, Liverpool and Glasgow, where demand is highest, would carry the proportionate burden of higher prices. That outcome is likely to impact voter sentiment with those who would pay more being disgruntled.

Whilst this report doesn't rehearse the case for or against zonal pricing, we would point the reader to the recent BBC article below for a summary of the main viewpoints.

[The huge sums energy firms get to not provide power - BBC News]()

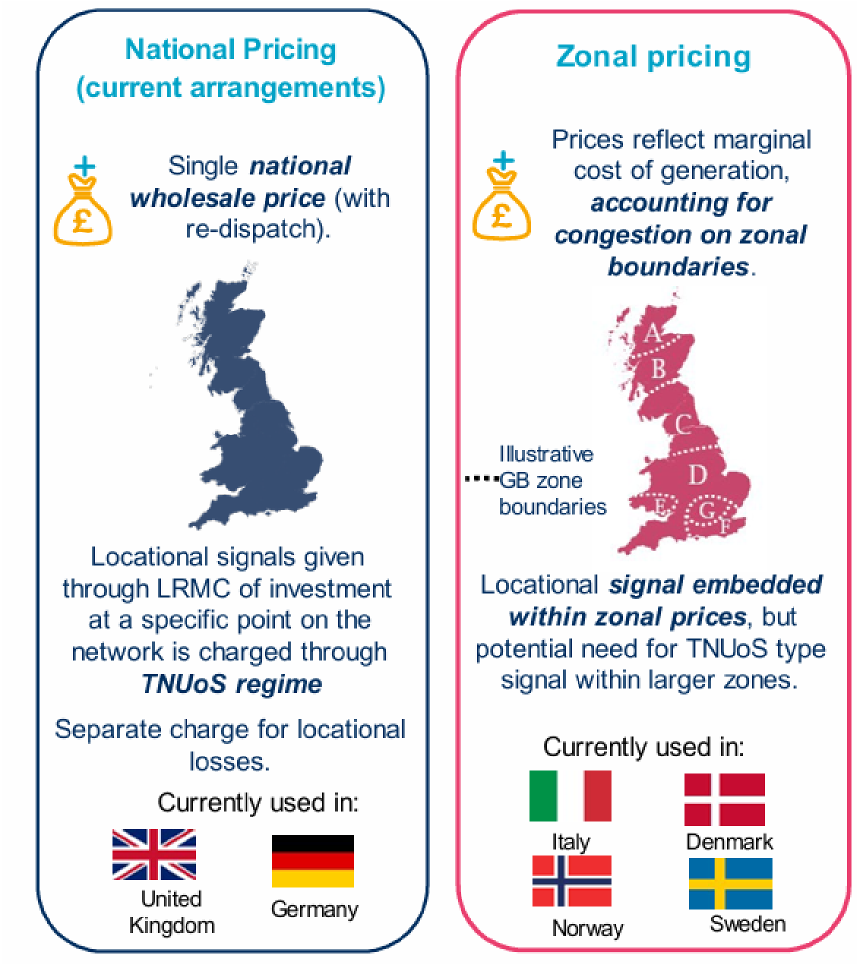


Figure 3: National pricing arrangements vs alternative zonal model

Source: LCP1-9-system-benefits-from-efficient-locational-signals.pdf (their Figure 2 and page 15); (LMRC=Long Run Marginal Cost)

Zonal pricing is being heavily promoted by some quarters (e.g. Octopus Energy and Amazon). Octopus suggest that zonal pricing could lead to: "*saving £3.7bn per year and avoiding £74bn of grid infrastructure investment*", as an effective solution to lowering consumer energy bills.

It's a market design that has been adopted in some countries, particularly those with a large land mass and dispersed population where it doesn't make economic sense to connect and maintain a single market network. This is often a function of geography, and the cost of building new generation is cheaper than building interconnection. For example, the US and Australia have developed a zonal market, where transmission and connection over long distances is deemed unnecessary and uneconomic. In the Nordics countries, zonal pricing is the mechanism for excess hydro power in Norway to reach the large German industrial demand.

Zonal pricing is suggested as a reason that existing industrial demand or new data centres could relocate to areas of lower electricity price. Extrapolating to this conclusion is attractive but has not been the experience in countries who have adopted zonal markets like Sweden, because the price of electricity is only one locational consideration out of numerous factors.

The assumption that electricity price alone determines this decision ignores other valid considerations such as certainty of price forecast, planning permission considerations, workforce mobility and other resources.

This position was recently considered in depth in a report for SSE plc by Aquaicity in which the locations of data centres was mapped across different pricing zones. Furthermore, this highlights reports of investment in northern located zones with lowest pricing as being cancelled or postponed.

Significantly, the markets in the countries zonal pricing have been deployed differ from the challenges that the UK needs to resolve for, as discussed below and the UK electricity grid is a benefit easily taken for granted.

How does zonal pricing compare to the current market design?

Currently, a single national electricity price applies across the entirety of the UK network for all consumers. The network price is often set by the price of gas, given that gas typically provides the marginal production to balance the system.

The existing single national price system allocates locational costs onto electricity generating projects in two categories known as Balancing Services Use of System or BSUoS and Transmission Use of Systems or "TNUoS".

Both of these costs need a forecast over the life of a project and will vary depending on factors outside of the control of the project itself.

BSUoS is charged for the service of balancing the transmission system. Costs are based on the volume of energy put onto or taken off the transmission system in a half-hour period. BSUoS is a flat tariff and was paid 50% by generators and 50% by consumers, until the recent code modification CMP308, that placed this entirely on demand.

TNUoS is the amount charged for the building, operation and maintenance of the transmission system. Generator TNUoS amalgamates four elements: (1) a locational element; (2)_a residual charge: (3) a local circuit charge; and (4) a substation charge.

TNUoS is calculated based on the Transmission Entry Capacity or "TEC" of a project, which is the nameplate of maximum capacity. The bigger the project, the larger the TEC and the higher the relative TNUoS cost.

Figure 4: Elements of TNUoS cost

TNUoS is the existing mechanism by which the UK electricity system provides a locational signal. Projects anywhere in the UK need to estimate what this cost line item will be and factor this into their investment decisions. The variability of TNUoS is more of a problem than the inherent size of the cost.

So whilst Great Britain has a single electricity system price, there exists significant disparity across the network in locational costs. ***Are these signals too weak, or being misunderstood or not driving the logical desired behaviour?***

Why is zonal pricing such a hot topic now…?

Primarily, because network costs have increased to the point where projects are too expensive and potentially faced with early decommissioning and shutdown.

In early 2024, the National Energy System Operator ("NESO") broke with convention and published a 10-year TNUoS forecast. If investors incorporated this forecast into existing investment valuation models, it would have an immediate financial impairment and damaged investor confidence. This release coincided with the ongoing REMA (see below), provided support of and promotion for zonal pricing.

For example, a 1GW wind farm in the North of Scotland would in 2034, be paying £71m per year, compared with £26m today, nearly a threefold increase. By comparison the same sized wind farm connecting into Pembrokeshire would **be paid** £23m per year compared with £5m today. (Simon Gill quote below)

TNUoS charges for the next ten years are published – the energy landscape

Rather than using the 10-year forecast as an investment assumption to underpin valuation, project sponsors used this to highlight the TNUoS problem in Scotland if reform of the existing system wasn't achieved.

In September 2024, in response to the 10-year forecast and an attempt to calm investor confidence, Ofgem published an open letter to industry on 30 September encouraging the NESO to develop a temporary cap-and-floor solution to the projected increasing cost and volatility of Transmission Network Use of System (TNUoS) charges.

Seeking industry action to mitigate the investment impacts of very high projected TNUoS charges | Ofgem

Therefore, OfGEM recognises that TNUoS charging needs to be resolved and fixed, but any changes will need delivered through the ongoing Review of Electricity Market Arrangements ("REMA") and be compatible with delivering investment required for Clean Power 2030. This uncertainty has brought zonal pricing into the reform conversation, with Octopus Energy one of the more vocal advocates of this design philosophy.

The current status is that the Autum REMA update published in December 2024, which summarises that both zonal pricing and national reform are still under consideration and a decision will be made in 2025.

REMA Autumn update 2024

Any individual infrastructure investment comes with the risk of delay. But the volume of grid upgrade over the coming decade, all competing for similar components, means this delay risk is compounded. Whilst the delay risk is manifest in a slower return to the capital to the network provider, it is the firm grid connection and therefore economics of the generation project that is disproportionately impacted. Additional costs to balance the network, if the grid upgrades are late, are passed through to the generation project in higher costs. This opens the generation project to the criticism of "being built in the wrong place" but fails to recognise that higher windfarm curtailment is just the symptom, when the cause is actually postponed or delayed grid investment.

In order to accommodate the growth of wind and solar generation, the Energy Networks Association (ENA) describes the £30bn investment planned by network operators during this current price control period as being "...the biggest programme of reforms in the history of the grid". Whether this investment should have started sooner in previous price control periods is now a moot point, but as we see in the zonal markets in Iberia in April, grid investment is an unavoidable political topic.

Whilst the climate and security of supply benefits from increase renewables penetration are positive to the UK, the investment in generation projects and grid infrastructure will be difficult to deliver at the same time as cheaper electricity.

Where is the wider policy context?

The government launched the first Review of Electricity Market Arrangements or "REMA" consultation in July 2022. In March 2023, the government published a summary of responses to the consultation and its updated policy position with regards to the options.

In March 2024, the government launched its second REMA consultation on specific proposals and a short-list of remaining options, as well as looking at how the remaining options interact with each other. The results of this consultation were published in December 2024.

The December 2024, REMA update stated appetite for reform; either zonal pricing or reformed national pricing. The reformed national pricing preference is to strengthen network charging alongside incremental reforms to balancing incentives

Review of electricity market arrangements (REMA): autumn update, 2024 - GOV.UK

This update stated electricity market reform is expected to work alongside the Clean Power 2030 Action Plan;

Technology	Current installed capacity[20]	NESO 'Further Flex and Renewables' Scenario	NESO 'New Dispatch' Scenario	DESNZ 'Clean Power Capacity Range'[21]
Variable				
Offshore wind	14.8	51	43	43 – 50
Onshore wind	14.2	27	27	27 – 29
Solar	16.6	47	47	45 – 47
Firm				
Nuclear	5.9	4	4	3 – 4
Dispatchable				
Low Carbon Dispatchable Power[22]	4.3	4	7	2[23] – 7
Unabated gas	35.6	35	35	35[24]
Flexible				
LDES	2.9	8	5	4 – 6
Batteries	4.5	27	23	23 – 27
Interconnectors	9.8	12	12	12 – 14
Consumer-led flexibility[25]	2.5	12	10	10 – 12

Table 1: Generation capacity growth anticipated for Clean Power 2030

Data Source: Clean Power 2030: Action Plan: A new era of clean electricity - Table 1, page 32

Recommendations by REMA are meant to be compatible with the ambitions of Clean Power 2030. This requires a significant growth in capacity of both onshore and offshore wind, as shown above, and confirmed that the timetable for REMA decisions will align with the timetable for the next allocation round of the Contract for Difference (CfD) scheme.

The Grid Problem...

The debate between National Market Reform and Zonal Pricing taps into a UK-wide problem, namely the spatial squeeze. Prioritisation and compromise is needed in a system that cannot accommodate a perfect solution. But no individual regulator exists to referee all these interests.

- Competing needs onshore include housing, agriculture, commercial development, renewable energy, and environmental protection
- Competing needs offshore include the subsurface (Oil, Gas, CCS), the sea bed (wind, aggregates, cabling), the water column (fishing, transport) and the airspace (wind and aviation)

But the UK also has a grid problem that was never designed for renewable generation but one that:

- Was designed for baseload generation, with production originally built close to demand.
- Is a system that doesn't reward and wasn't designed for storage.

- Has inefficient dispatch creating counterintuitive flows of electricity (e.g. the UK could be importing electricity from Norway via the interconnector, but curtailing onshore wind generation in Scotland)
- Has increasing generation curtailment to manage grid balance
- Ignores the hidden costs of risk if the TSO decides not to invest, in the objective of lower consumer bills
- Has an inappropriate or controversial allocation of costs to balance the grid.

The UK's ambition to be a Clean Super Power by 2030 relies upon significant investment into new generation projects, but current market conditions in offshore do not marry these objectives.

- Recent withdrawal of integrated energy companies with a significant oil and gas footprint (e.g. BP and Shell) from offshore wind projects
- Reported 40% increase in costs across global supply chains
- Whilst commercially sensitive, virtually all ScotWind projects are up for sale or currently seeking fresh investment to reduce their financial exposure, highlighting weak investor confidence

These factors combine to represent significant headwinds to Clean Power 2030 and the Energy Transition targets.

New projects will require new investment in grid networks. This will need finance and delivery by the incumbent grid operators and the cost of upgrade will filter into higher consumer bills, something that should be openly acknowledged.

On the positive side, the additional projects will incrementally enhance our domestic energy production, improve energy security and incrementally reduce reliance on gas to set the price of electricity.

Investor confidence and project leverage

The growth of UK renewables has been a success story that has attracted large-scale investment from lower cost capital in the form of Sovereign wealth funds and International pension schemes.

In the UK, the height of this investor confidence was arguably in 2021 when Crown Estate Scotland successfully raised £755m in option fees for the ScotWind projects and The Crown Estate in England achieved £879m per annum for three years.

The investment landscape has changed since these transactions. The macroeconomics are worse with much higher interest rates, whilst the micro project economics are burdened by higher supply chain cost estimates. However, these are all global phenomenon and doesn't set the UK apart from other competing nations.

However, the uncertainty that a redesign of the electricity markets to incorporate zonal pricing is a UK specific problem that does have the potential to undermine investor confidence. Without an ability to accurately forecast both revenues and costs for 25+ years, projects cannot accurately demonstrate sufficient cashflow cover to service project finance debt packages.

This will impact the borrowing ratios, reducing from c.70% debt today as projects will need to demonstrate to a bank syndicate full repayment in a wide possibility of revenue and cost scenarios. Any reduction of debt in the capital structure will need plugged through additional equity investment. Having to contribute a large proportion of the capital will have a disproportionate impact on the Internal Rate of Return ("IRR") and potentially reduce returns below those required for a Financial Investment Decision ("FID").

This borrowing ratio is the confidence trick of project finance. Convincing lenders that debt repayment is assured in a narrow range of outcomes enables a higher debt % contribution to the construction costs. Zonal pricing will create additional uncertainty and volatility within the system, making cashflow forecasts less certain and achieving these ratios more challenging.

Retaining existing levels of gearing in projects through whatever changes REMA proposes should be an objective consistent with achieving Clean Power 2030.

Alternative ideas

Afry have highlighted a number of alternative measures to zonal pricing. Whilst these ideas don't benefit from the promotion of industry champions, they merit strong consideration.

[Enhanced National electricity market designs for Great Britain | AFRY]

Improvements for small-scale and storage assets within an enhanced national design are recommended, providing realistic gains.

Of particular note is the way Interconnector projects interact within the UK and European markets. Interconnectors will contractually agree to the direction of electricity flow 24 hours in advance of gate closure (sometimes longer), which means a significant volume of capacity cannot respond to intra-day conditions and markets. This inefficiency can result in scenarios that whilst the UK is importing electricity from Norway, it can at the same time be curtailing domestic windfarms in Scotland. Managing interconnectors closer to the point of gate closure would potentially provide additional system benefits.

TNUoS itself is a good proxy for locational cost and this varies in the UK across the 27 different zones. The problem for operational assets arises when this cost forecast significantly changes, outside of what a project can control. Providing certainty on TNUoS costs, either fixed or through a cap and floor arrangement would enhance investor confidence.

The risk of delaying grid redesign

Any individual infrastructure investment comes with the risk of delay. But the volume of UK and European grid upgrade over the coming decade, means this delay risk is compounded and unprecedented.

Whilst project delay leads to a slower return to the capital to the network provider, it is the firm grid connections and therefore economics of the generation project that are disproportionately impacted. Additional costs to balance the network, if the grid upgrades are late, are passed through to the generation project in higher operating costs.

This opens the generation project to the criticism of "being built in the wrong place", when the windfarm has to respond to instructions from the grid operator to curtail generation. But this fails to recognise that higher windfarm curtailment is just the symptom, when the cause is actually postponed or delayed grid investment. This highlights the need for strategic spatial planning, because the generation project only takes one Financial Investment Decision in its' life and cannot move location.

There needs to be an acknowledgement of the urgent need to upgrade the network. Whilst we cannot change the history of network investment decisions, we can control the future pathway and the system needs better quantification of the problem. Without timely system upgrades in transmission and balance of plant, generation projects will not attract investment and Clean Power 2030 and beyond will be missed opportunity.

The case for zonal pricing in Scotland?

In March 2024, the Energy Statistics for 2023 in Scotland were published.

[Energy Statistics for Scotland - Q4 2023 - gov.scot]

These statistics show a 10% growth over 2022 generation capacity, but also highlight that Scottish projects generated 33TW/h of electricity, approximately 33% more than the Scottish consumption.

This highlights why, in a world of zonal pricing and reduced network infrastructure investment, further build-out of renewable projects in Scotland would slow and potentially reverse as projects reach maturity.

Rather than electricity prices in Scotland falling post introduction of zonal pricing, it is more likely that future generation projects will not built because the demand for electricity does not current exceed supply. At the very best, electricity prices would remain at current levels and at worse, new generation projects and investment in Scotland is cancelled.

The uncertainty created by an inability to predict revenue and costs accurately will reduce leverage and investment into Scottish based projects. The balance of existing electricity supply and demand in Scotland means zonal pricing does not offer an easy route to cheap electricity prices.

Recommendations and Solutions

On balance, zonal pricing does not provide an obviously better, cheaper or more secure system, because the uncertainty will undermine already fragile investor confidence. Whilst the principle of having cheaper prices close to generation might be politically attractive in some regions, it will carry negative consequences for households who will receive higher bills with resultant political consequences in energy hungry areas expressed by loss of votes.

The existing programme of grid investment will provide significant upgrade to the electricity system and broad support of this endeavour will be needed to see this change through each of the following:

1. Market design changes

   a. Interconnector management needs to be more closely aligned to network constraints by bidding nearer to gate closure
   b. NESO visibility of and access to small-scale assets, to enable these assets to participate in grid stability and maintenance
   c. State of charge information needs to be shared with NESO to facilitate efficient battery use, to enable enhance confidence of response

2. A wider acknowledgement that underinvestment in grid infrastructure creates delay, risk and cost elsewhere in the system. There is a need to create a better dialogue, engagement and understanding of the importance and value that grid infrastructure investment can bring, before that risk manifests itself in blackouts as seen in the Iberian peninsula.
3. Retain TNUoS as the locational signal within the UK yet provide a mechanism to fix this cost forecast at the point of Financial Investment Decision. Fixing either by reference to specific forecast or by a cap and floor mechanism that retains some element of cost flexibility, but only to the extent compatible with raising the third-party project finance.

APPENDIX 1 – Useful Definitions

- CfD – Contract for Difference
    - The contract that underpin the majority of revenues for an offshore wind project. This is provided by the Low Carbon Contracts Company ("LCCC"), a wholly owned UK Government body. Projects bid for a CfD in annual Allocation Rounds ("AR"), with AR7 expected in 2025. Bid criteria include planning consent and a grid connection offer with a date that corresponds to the target delivery window in the relevant AR.
- TNUoS – Transmission Use of System – the cost that projects pay for grid access.
    - Generation TNUoS charges depends on the type of connection and the size in MW of your Transmission Entry Capacity (TEC). Project sponsors need to estimate this cost for the life of the project and significant variations limit the ability to raise capital (debt). A bit like trying to get a mortgage to buy a house without a full time job

Transmission Network Use of System (TNUoS) Charges | National Energy System Operator

- NESO – National Energy System Operator

National Energy System Operator (NESO) | National Energy System Operator

Authors

Matthew Porter ~ is a seasoned renewable infrastructure and investment professional with over 25 years of experience spanning both the public and private sectors. He was a founding member of the UK Green Investment Bank in 2013 and later joined Macquarie Group, where he spent nearly eight years working across its Green Investment Group and as Head of Investment Management for Corio Generation, an offshore wind platform. Matt has served as a Board director for numerous UK offshore wind projects through development, construction, and operational phases. In 2025, he founded NextLife Energy, an investment vehicle focused on operational onshore wind opportunities.

Professor John Underhill ~ is the University Director for Energy Transition at Aberdeen University. He has had a distinguished academic career based at Edinburgh, Heriot-Watt and Aberdeen Universities. While at Heriot-Watt, he helped establish the Lyell Centre for Earth and Marine Science and Technology and was University Chief Scientist. His research focuses on the role of geoscience in the energy transition and use of technologies, methods, and data to deliver low-carbon net zero goals. He has led the GeoNetZero Centre of Doctoral Training, a £22M academic-industry pan-UK partnership comprising 12 Universities and 8 companies and chaired the National Energy Skills Accelerator (NESA), where he helped secure £1M from the Scottish Government's Just Transition Fund to up- and re-skill workers for careers in renewable energy. John populates the UK Subsurface Task Force and was on the Scottish Science Advisory Council (SSAC), the leading independent advisory board for Scottish Government.