TRANSMISSION CHARGING IN SCOTLAND: JEOPARDISING BRITAIN'S ENERGY TRANSITION

A report prepared for Scottish Renewables

TEL
the energy landscape

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EXECUTIVE SUMMARY

Delivering a clean electricity system depends on new renewable generation in Scotland, but Transmission Network Use of System (TNUoS) charges have long posed a challenge for Scottish generators. Today, the scale, uncertainty, and impact of these charges have increased significantly. They now represent a direct risk to Britain's energy transition.

This report explores the implications of recent work published by Scottish Renewables, which highlights the growth in TNUoS charges across the whole Scottish generation fleet for future investment in Scottish generation and for the energy transition.

Transmission charging has become a critical barrier to delivering a decarbonised, secure and affordable electricity system. Recent and unexpected increases in forecast charges are imposing windfall costs on existing assets with no ability to respond, undermining investment, raising consumer costs and increasingly working against Government's strategic spatial plans for the energy system.

Existing issues

TNUoS has always been stacked against Scottish generators and, together with the CfD framework, works against the interests of consumers.

New issues

- Sharp increase in scale and volatility
- Erodes project value
- Direct impact on capital available for investment in new generation
- Adds to existing market headwinds
- Creates bad outcomes for consumers
- Risks early closure of operating generators
- Fails to align with strategic planning

£2.9 billion increase in the TNUoS bill for the Scottish fleet compared with point of investment or 2015

How to reform TNUoS

Three simple steps can stabilise investment and align TNUoS with Britain's strategic energy goals:

1. Fix TNUoS for **existing projects** in real terms at the charging level prevailing at the time of their original CfD bid (or for non-CfD projects, at the time they reached an investment decision), reversing the erosion of project value;
2. Fix TNUoS for **new projects** in real terms at the level prevailing when they bid into a CfD auction, restoring investor confidence; and
3. Launch a **fundamental review** to align TNUoS with the Strategic Spatial Energy Plan.

TNUoS is no longer a useful locational signal

What began as a mechanism to influence the siting of fossil fuel generation has become a material barrier to delivering a decarbonised, secure and affordable electricity system. It now acts as a barrier both to Scotland's ambitions and to the delivery of the energy transition across Great Britain.

The scale and volatility of TNUoS has increased dramatically

Recent forecasts show some Scottish TNUoS charges more than doubling between 2025 and 2030, a level of change that was not anticipated when most of today's generation fleet reached investment stage.

Across all generators in the Scottish generation fleet, lifetime charges have increased by £2.9 billion

The Scottish TNUoS bill has grown substantially compared with expectations at the time of investment (or in 2016 for older assets), falling on projects with no practical ability to respond.

Existing projects are exposed to windfall losses with no system benefit

Once built, generators cannot change location or materially alter behaviour. Unexpected and escalating charges erode asset values, undermine investor confidence, restrict capital recycling and in extreme cases risk premature closure of assets the system still needs.

The impact extends across technologies and is significantly magnified in the north of Scotland

A 500 MW offshore wind farm in northern Scotland could see annual TNUoS charges rise from £13 million in 2025 to £27 million by the end of the decade. A 50 MW battery in north east Scotland could see charges rise from £0.64 million to £1.22 million over the same period. Meanwhile, generators in the southern half of Britain receive TNUoS payments, increasing the costs that must be covered by northern generators and recovered from consumers through bills.

Higher TNUoS feeds directly into higher costs for consumers

The development of the GB electricity system depends on continued investment in Scottish generation. Elevated and uncertain TNUoS increases risk premiums in Scotland, raises the cost of capital and drives higher CfD bid prices. These higher strike prices flow directly through to consumer bills. Government has already partially recognised this by increasing administrative strike prices in recent CfD rounds, in part reflecting higher TNUoS uncertainty.

There is a growing risk of inefficient early closure

For some assets, rising TNUoS combined with other pressures could wipe out operating margins, and in extreme cases potentially driving the premature loss of low-carbon capacity at a time when every megawatt is needed.

The current charging regime is misaligned with strategic planning

TNUoS now actively works against UK and Scottish Government objectives, including Clean Power 2030 and NESO's emerging Strategic Spatial Energy Plan, by discouraging investment in exactly the locations where generation is required by the plan.

ACTION IS NEEDED NOW

In the short term, **charges for existing renewable projects should be reset and fixed** at levels expected at the time of investment, specifically at the point of the CfD bid. Similarly, **charges for new projects should be fixed** at levels reflective of TNUoS at the time of their CfD bid. This will restore project value, improve the ability to recycle capital into new projects and build investor confidence. In parallel, a **fundamental reform of TNUoS** is needed so that transmission charging supports, rather than undermines, a strategically planned electricity system and delivers least-cost outcomes for consumers.

WHY TNUOS MATTERS, WHY SCOTLAND MATTERS

Scotland and the energy transition

Scotland has its own ambitious targets for the energy transition and for a just transition away from oil and gas. Building on the success of the last 15 years, Scotland aims to have 20 GW of onshore wind operational by 2030 and up to 40 GW of offshore wind by 2040. There are also significant opportunities to expand energy storage capability, including grid scale batteries and new pumped storage schemes.

The benefit of these targets extends well beyond the energy system itself. They are expected to deliver substantial green economic growth and support a growing pool of jobs, both within the electricity sector and across its extensive supply chain.

Scottish generation is not only important for Scotland; it is critical to the energy transition across Great Britain. The UK Government's Clean Power 2030 Action Plan targets 10 to 12 GW of offshore wind in Scotland by 2030, alongside 18 to 20 GW of onshore wind. This represents increases of around 160 percent and 80 percent respectively relative to capacity operating in 2024. In addition, the plan includes a further 1.8 to 2.3 GW of solar and a total of 6 GW of operational battery storage[1] (Figure 1).

Beyond 2030, Scottish generation will continue to be important to Britain's energy future. The Longer term Strategic Spatial Energy Plan (SSEP) is still in development, however a wide range of industry modelling, including NESO's Future Energy Scenarios, indicates that a growing Scottish generation fleet will play a central role in meeting Great Britain's targets.

This makes it essential that transmission charging arrangements are aligned with the continued investment required in Scottish generation.

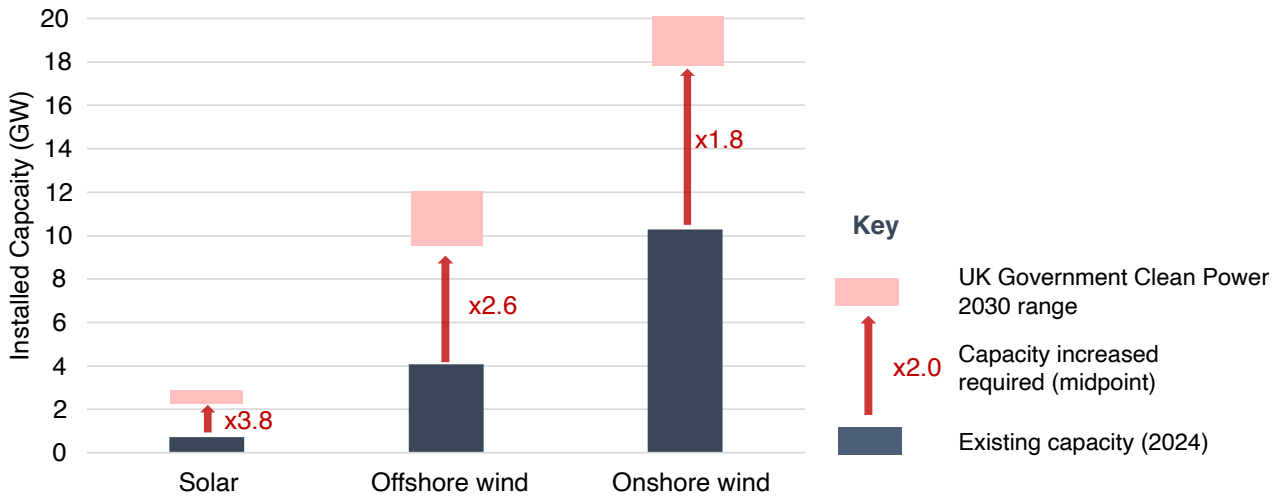

Figure 1: The Increases in capacity of Scottish renewable capacity between 2024 and 2030 set out in NESO's advice to government and the UK Government's Clean Power 2030 Plan. (Sources: NESO, UK Government, Scottish Government[2])

The cost of transmission

TNUoS is the mechanism through which the costs of operating and expanding the GB transmission network are recovered. Those costs are now increasing dramatically. In 2015, the annual cost of the GB transmission network was just under £4 billion and remained broadly flat for most of the previous decade. Forecasts published in 2025 show that this figure is now expected to rise to over £12 billion per year by 2030 (Figure 2).

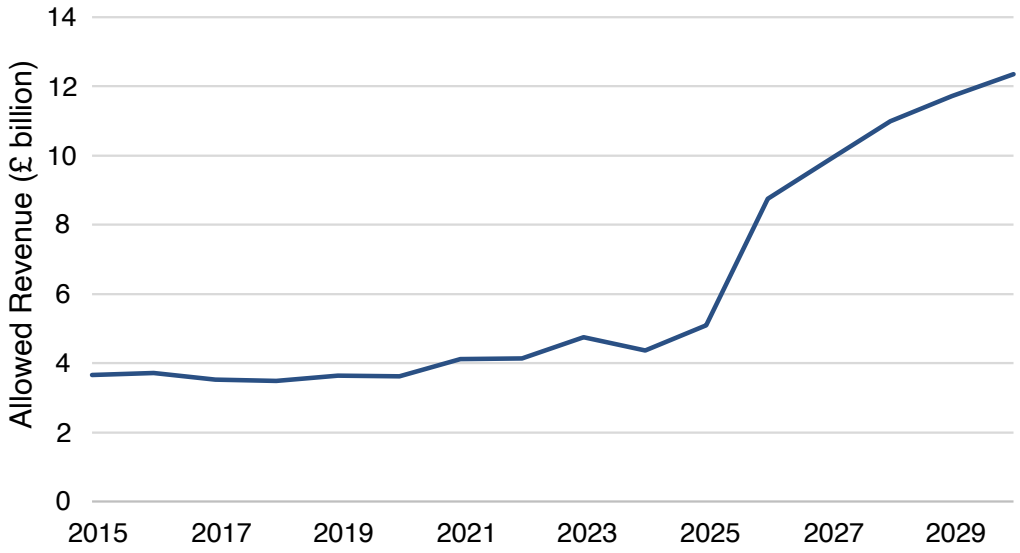

Figure 2: Cost of the transmission network recovered through TNUoS (Source: NESO[3])

This sharp increase reflects both the scale and nature of network investment required to deliver Clean Power 2030, Britain's and Scotland's longer-term decarbonisation pathways and the need to ensure energy security and a just transition. It is driven by the volume and pace of new transmission build-out and by increased reliance on more expensive solutions such as subsea HVDC links between Scotland and England rather than cheaper onshore overhead lines.

Ambitions to decarbonise the power system have existed for more than two decades. However, until recent years there was no transparent, strategic plan for the electricity system as a whole. As a result, the scale and timing of the increase in transmission costs remained unclear until planning began to shift onto a more strategic footing from around 2023.

The majority of transmission costs are recovered from electricity demand, via suppliers, rather than from generation. In the 2026/27 forecast, around 85% of the £7.75 billion TNUoS total is expected to be collected from demand TNUoS, and therefore directly from consumers' bills[4]. In principle, these higher network costs should be offset by lower wholesale energy costs delivered from a renewables-based system, but only if that generation can be financed and delivered efficiently.

This makes it essential that TNUoS does not become a barrier to renewable investment. However, while generation contributes only a minority of the cost of transmission, the way those charges are allocated is increasingly problematic.

Recent work published by Scottish Renewables highlights the extent to which TNUoS costs are rising for all types of Scottish generators. This is driven in part by the overall increase in TNUoS charges, but also by the methodology used to calculate the charges. This paper explores what is driving that increase, the implications for investment in Scottish generation of all types and what could be changed so that TNUoS supports, rather than hinders, the energy transition.

The barriers created by current charging arrangements

Generation TNUoS aims to be cost-reflective of long-run transmission investment costs. However, the methodology was developed for a very different electricity system: one dominated by large fossil fuel and nuclear power stations, with relatively stable patterns of generation and predictable, incremental network reinforcement.

Under those conditions, locational charging provided a useful signal. Generators that increase the need for transmission faced higher charges, while those that have a smaller impact on costs face lower charges.

Today, that same methodology is increasingly misaligned with the system it is applied to. It now delivers volatile and hard-to-predict charges for generators in Scotland, while providing growing payments to generators in the south of England and South Wales to connect and use the system. It also increasingly fails on its own terms with key assumptions on the transmission costs that generation projects drive diverging from emerging evidence (See Box 1).

Applied to onshore and offshore wind, these signals are diametrically opposed to the geographical distribution needed to deliver the Government's strategic plans and Scottish Government's ambitions for ScotWind and its 2030 onshore wind target.

The barrier created by TNUoS operates in two ways:

- **The absolute level of charges** discourages investment in Scotland, despite world-class wind resources, strong policy support and an established supply chain.
- **The unpredictability of how charges evolve** over time creates material risk for projects, undermining investment decisions and leading to poor outcomes for consumers.

This paper unpacks the implications of this dual-barrier and shows we need to take action to change the way the GB transmission network is paid for.

Box 1: TNUoS and cost reflectivity:

The TNUoS methodology is set out in the Connection and Use of System Code (CUSC)[5] , managed by NESO and overseen by Ofgem. It is built around two core principles:

- **Cost recovery:** total charges should recover the revenue Ofgem has allowed transmission owners to earn.
- **Cost reflectivity:** generators and consumers are charged based on their estimated contribution to long-run transmission investment costs.

To deliver cost reflectivity, the methodology estimates how additional generation or demand in each location affects the total transmission capacity required and the associated long-run investment cost. Charges are calculated on a marginal basis, meaning all users face charges based on the current marginal impact of new capacity rather than the circumstances prevailing when they reached investment and the network was upgraded to connect them.

TNUoS is not intended to influence operational behaviour. Its purpose is to shape long-term location decisions for generation (and, where relevant, demand).

Over the past five years, the methodology has become increasingly complex as it has attempted to accommodate a wider range of technologies with very different impacts on the network. This has raised concerns about both how effective it is at delivering cost reflectivity and whether that objective remains appropriate. In particular, current TNUoS charges:

- Vary significantly year to year, even for existing assets with no ability to respond after investment.
- Depend heavily on contested assumptions, such as the unit cost of new transmission and the level of network redundancy driven by new generation[6].
- Rely on increasingly complex scenarios and technology classifications.
- Are influenced by non-cost-reflective constraints, including compliance with European rules on maximum charges to generators.

The locational slope

The cost-reflective design leads to a significant locational slope in TNUoS charges. Over the coming years that slope is expected to steepen significantly (Figure 3). This means not only that northern generators face higher charges, but that the differences between locations are becoming much larger.

One consequence of the current approach is that generators in the southern half of GB receive a payment (sometimes called a TNUoS credit). Both the scale and the geographical area over which generators will receive TNUoS credits is growing, leading to more generators being paid and paid more rather than contributing to the growing cost of the transmission system.

To illustrate this, consider a 500 MW offshore wind farm that reached investment decision in 2016:

- If located in northern Scotland, its TNUoS charge today would be around £14 million per year, while an equivalent project in the south of England would receive a payment of around £5 million.
- For the Scottish project, charges have nearly doubled since investment, from £8 million in 2016 to £14 million today, and are forecast to more than double again to around £29 million by the end of the decade.
- Over the same period, an equivalent project in the south of England would move from broadly neutral TNUoS at the point of investment to receiving a payment of £2 million today, rising to £5 million by the end of the decade.

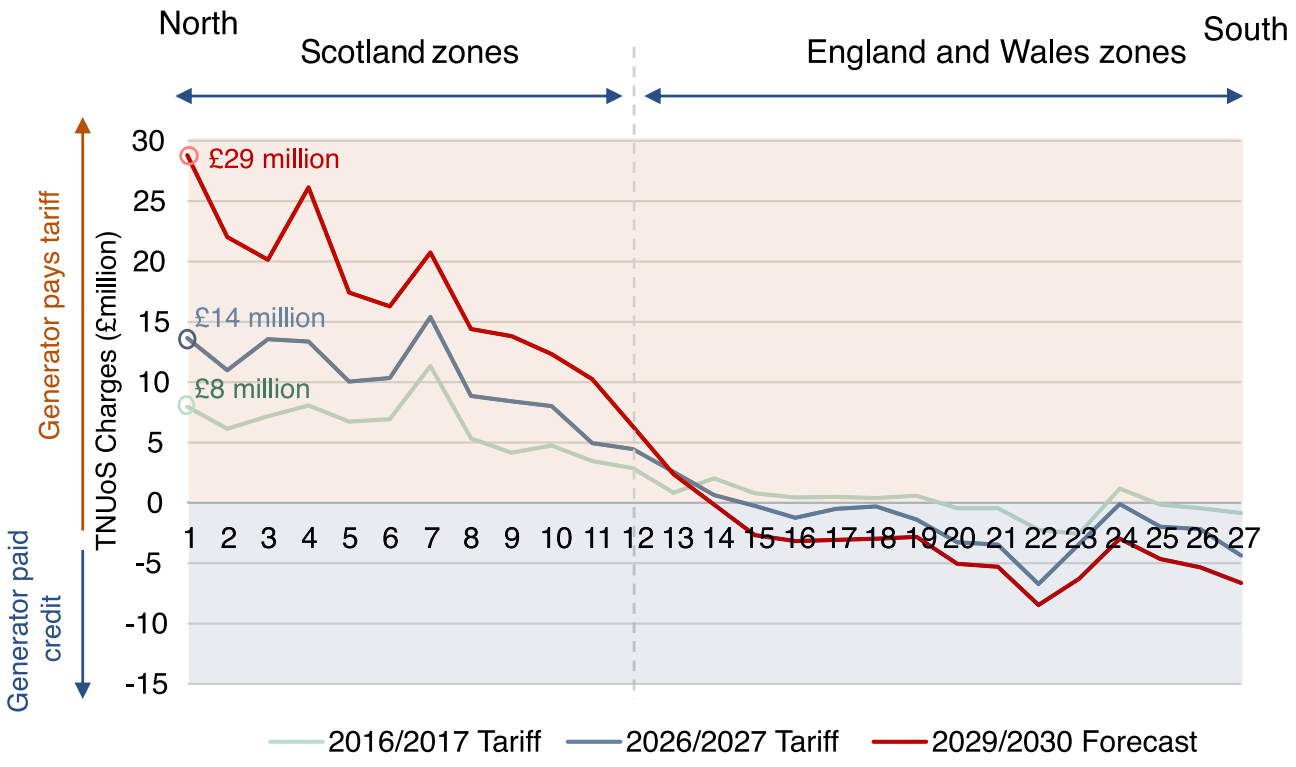

Figure 3: TNUoS charges for a 500 MW wind farm. The graph shows the increasingly steep locational slope for TNUoS and the increasing level of negative charges – TNUoS credits – for southern generators (Source: adapted from NESO[7])

A similar pattern applies across other technologies. For example, a new dispatchable generator such as a gas plant with carbon capture and storage would today pay around £5.4 million in central Scotland, while receiving a payment of around £3.3 million in South Wales. Scottish dispatchable generators also face significant increases in charges over time.

TNUoS variations within Scotland

The increasing locational slope of TNUoS charges means these issues now apply within Scotland itself, not just between Scotland and southern England. By 2030, the variation in TNUoS within Scotland is forecast to exceed today's variation across Great Britain as a whole (Figure 4). This risks rendering wind projects in the north of Scotland, including a significant share of planned ScotWind capacity, significantly less financially viable, even relative to projects elsewhere in Scotland. It remains essential that the Scottish generation mix evolves to deliver low-cost outcomes for consumers, but the current charging framework works against that objective and risks preventing delivery of the strategic plan.

While the sector has previously recognised this issue at a GB-wide level, NESO's 2025 forecasts make clear that it has now become an acute problem within Scotland itself.

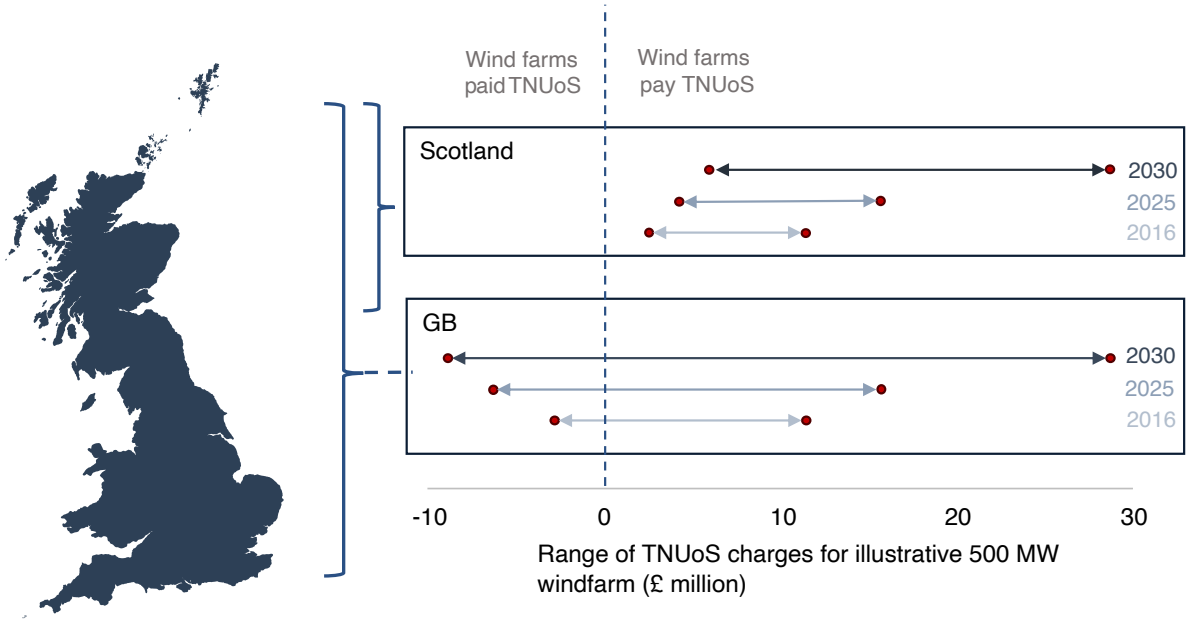

Figure 4: The variation of TNUoS charges across GB and Scotland. By 2030 the range in charges within Scotland – the difference between the maximum and minimum - will be larger than the variation across the whole of GB today (Source: adapted from Scottish Renewables[8])

TNUoS and the transition

The context of the energy transition amplifies the problems that TNUoS causes. The transition means a wholesale transformation of the electricity system: rapid growth in renewable capacity, changing patterns of demand and an increasing role of flexibility to balance the system. Combined with the scale of planned transmission investment and the growing cost of the network, this makes TNUoS outcomes almost impossible to predict under the current methodology, overwhelming any marginal efficiency benefits of cost reflectivity.

Another factor is the changing cost structure of generation. Renewable projects are highly capital-intensive, with long payback periods and limited ability to absorb post-investment cost shocks. While the CfD scheme mitigates some revenue risk, the interaction between CfDs and TNUoS means that higher and more volatile transmission charges ultimately feed through to higher strike prices and higher costs for consumers. **Previous analysis by Ocean Winds, Northland Power, and West of Orkney Windfarm** suggests that minimising the locational element of TNUoS could reduce consumer costs by £16.2 billion between now and 2050.

Transmission investment will continue to rise beyond the early 2030s as further reinforcements are required. These investments are essential. But unless the charging framework evolves alongside strategic planning, the result will be higher costs for Scottish generators, increased risk for investors and poorer outcomes for consumers.

THE ISSUES WITH TNUOS TODAY

Unprecedented growth and volatility for Scottish generators

The challenges created by TNUoS are about to grow much larger. The latest five-year forecast, published by NESO in August 2025, shows that some parts of Scotland could face a doubling of their TNUoS costs by the end of the decade. The impact differs by technology and location, but it is significant across all types of generation and all areas of Scotland. For a wind farm in North Scotland, charges are expected to double between 2025 and 2029; for a hydro generator in the Trossachs, they will increase by around 62%; and for a biomass power station in southwest Scotland, about 77% (Figure 5).

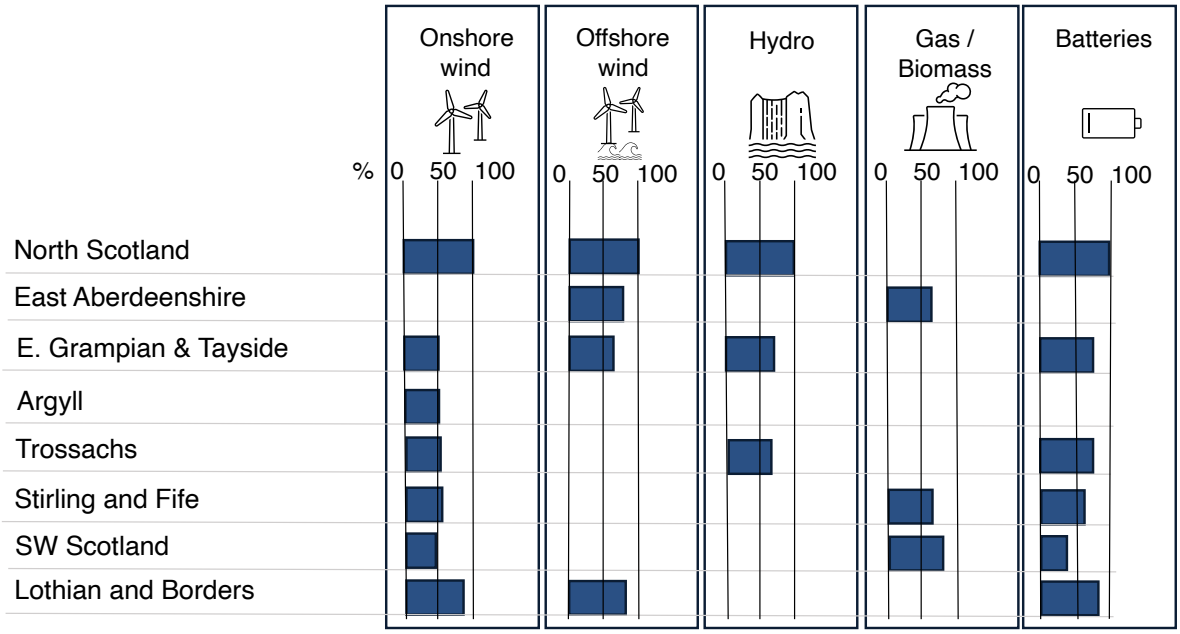

Figure 5: Increase in annual TNUoS charges between 2025 and 2029 by technology and zone (Zones without generation are blank) (Source: adapted from analysis published by Scottish Renewables[9])

We can estimate the increase in the expected lifetime TNUoS bill by comparing an estimate made today, using the most recent 2025 forecast, with estimates made based on TNUoS forecasts available in the year each generator made its investment decision, or for older assets, by using the 2015 forecast of charges from 2016 onwards as a reasonable proxy for later refurbishment investments.

By comparing these two we get a sense of the volatility introduced by TNUoS. The result is stark: Scottish generators today face an additional £2.9 billion cost compared with reasonable expectations at the point of investment in 2016. That is a 40 percent increase. The increase is both unforeseen and unavoidable. It delivers no useful signal, erodes £2.9 billion from the value of Scottish projects, lowers investor confidence and reduces the capital which can be recycled into new projects (Figure 6).

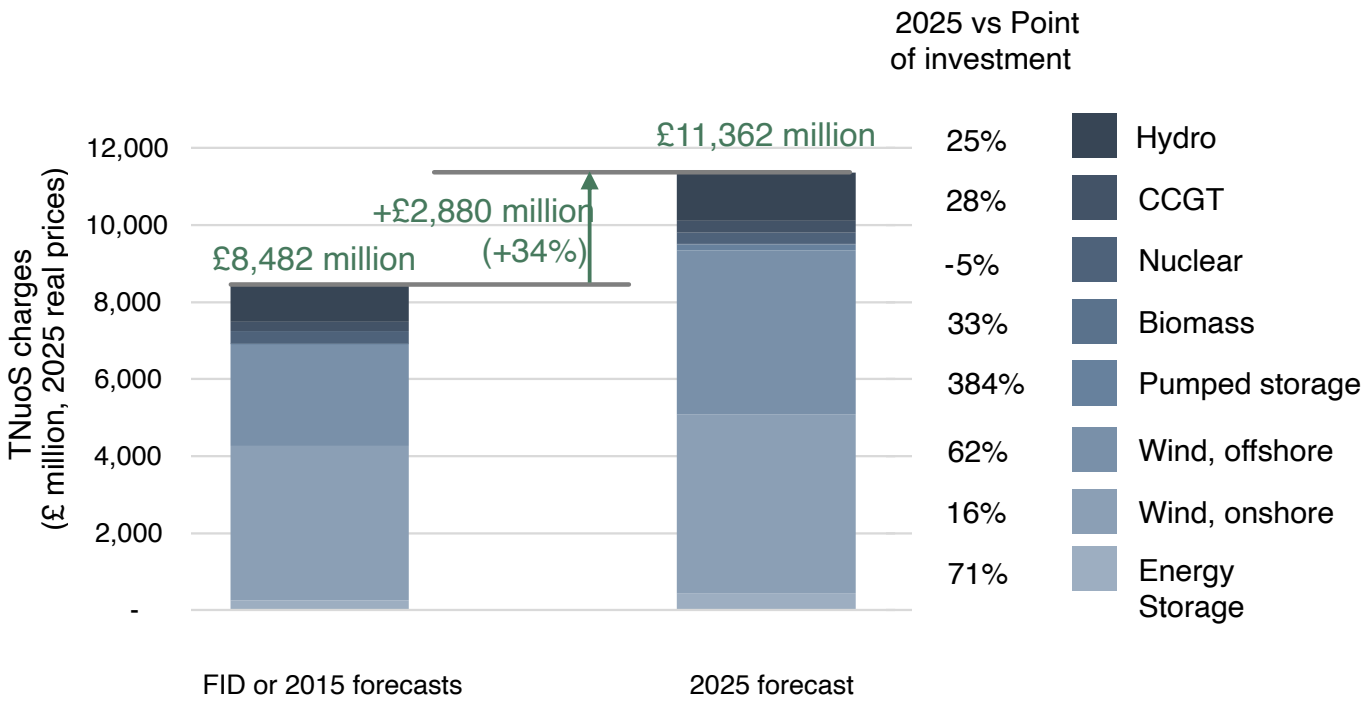

Figure 6: The increase in the Scottish TNUoS bill for today's generation fleet between investment and today (Source: adapted from analysis published by Scottish Renewables[10])

The increase in those charges is driven by both the growing cost of the network and the outdated approach to TNUoS. They will have a major impact on expected lifetime costs that existing projects will face compared with the levels anticipated at the time of investment.

Whilst the increase is significant for all technologies, it is particularly significant for offshore wind which faces 57% of the increase despite accounting for only 24% of the installed capacity.

TNUoS erodes project value...

The increase in TNUoS expected over the coming years represents a cost that was never built into the original investment decision for these projects. Now that the assets are operational, there is little that generators can do to reduce their exposure. TNUoS charges are levied on operational capacity and, short of shutting down, projects are obliged to pay the bill that NESO issues each year.

Using a hypothetical 500 MW offshore wind farm in North Scotland as a case study (Figure 7):

At investment decision in 2016, with a forecast commissioning date of 2019:

- Charges for this project were around £12 million a year measured in 2025 prices. The most recent forecast at the time from National Grid System Operator (the predecessor to NESO) showed charges remaining approximately constant across the forecast period, which ran to 2021.
- To estimate lifetime liabilities, projects make assumptions about how TNUoS will evolve beyond the forecast period. At the time, it was a standard assumption that charges would stay approximately constant in real terms. This was driven by a lack of understanding about how the system was likely to develop over the coming decades and a complex methodology which includes a fixed cap on average TNUoS of €2.50 set by the European Union and retained by UK Government at Brexit.
- **Therefore, a reasonable estimate for the total lifetime transmission charges bill at the point of investment would have been around £383 million.**

In 2025:

- Between 2019 and today, TNUoS charges have been slightly higher than the 2016 forecast predicted. The case study project would have paid around £14 million in 2025 compared with £12 million based on the 2016 forecast.
- However, the 2025 forecasts now suggest annual charges will more than double by the end of the decade, reaching £29 million a year in 2029, before easing slightly the following year.
- Using the same principle as applied to the 2016 forecast, no further real-terms increase beyond the end of the NESO forecast, the **estimated lifetime TNUoS liability is now around £769 million, more than double the expectations at the point of investment.**

Value eroded:

- **The difference in estimated lifetime TNUoS costs between the 2016 and 2025 forecast is a direct erosion of project value equal to £387 million.**

Investors evaluate and price risk as perceived at the point of investment, but they do not plan for unexpected policy-driven costs of this scale. The increases do not simply reduce profits, they drain capital from the system that would otherwise be recycled into new projects, slowing the flow of investment at the point it is most needed.

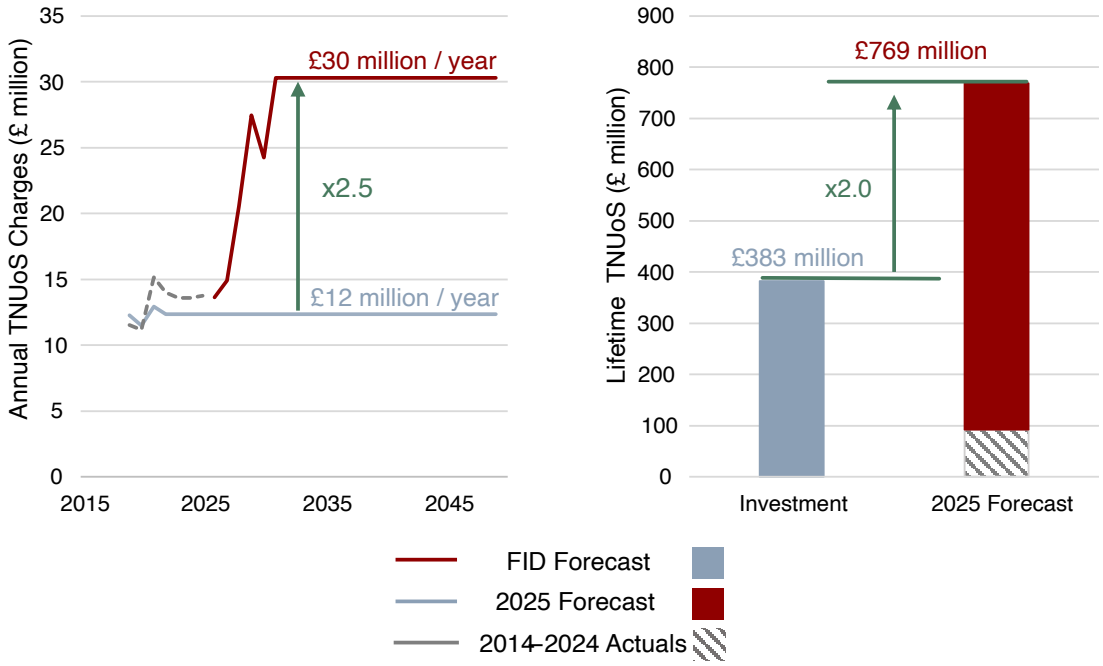

Figure 7: Expected lifetime TNUoS liabilities for an illustrative 500 MW commissioning in 2019. The two graphs show expectation in 2025 prices at the point of investment in 2016 and in 2025 (Source: adapted from analysis published by Scottish Renewables[11])

...which reduces the availability of capital to recycle into new projects

The windfall loss from rising TNUoS charges has a direct impact on the capital available to fund new projects. Investors at the construction stage are skilled at managing complex risks such as construction delays, supply chain disruption and coordination with transmission owners and system operators. They accept these risks for a fair return that reflects the challenges of building new assets.

Once projects are completed, these investors typically sell their stake to long-term owners such as pension funds, which seek operational assets that are lower risk and deliver a lower but more predictable return. This process allows the original investors to release capital and recycle it into the next wave of development (Figure 8).

When increasing TNUoS charges create significant windfall losses, sale value falls because future costs increase and expected returns decline. The result is a direct reduction in the funds that can be reinvested into new generation capacity, slowing the pace of delivery at the very time when it needs to accelerate.

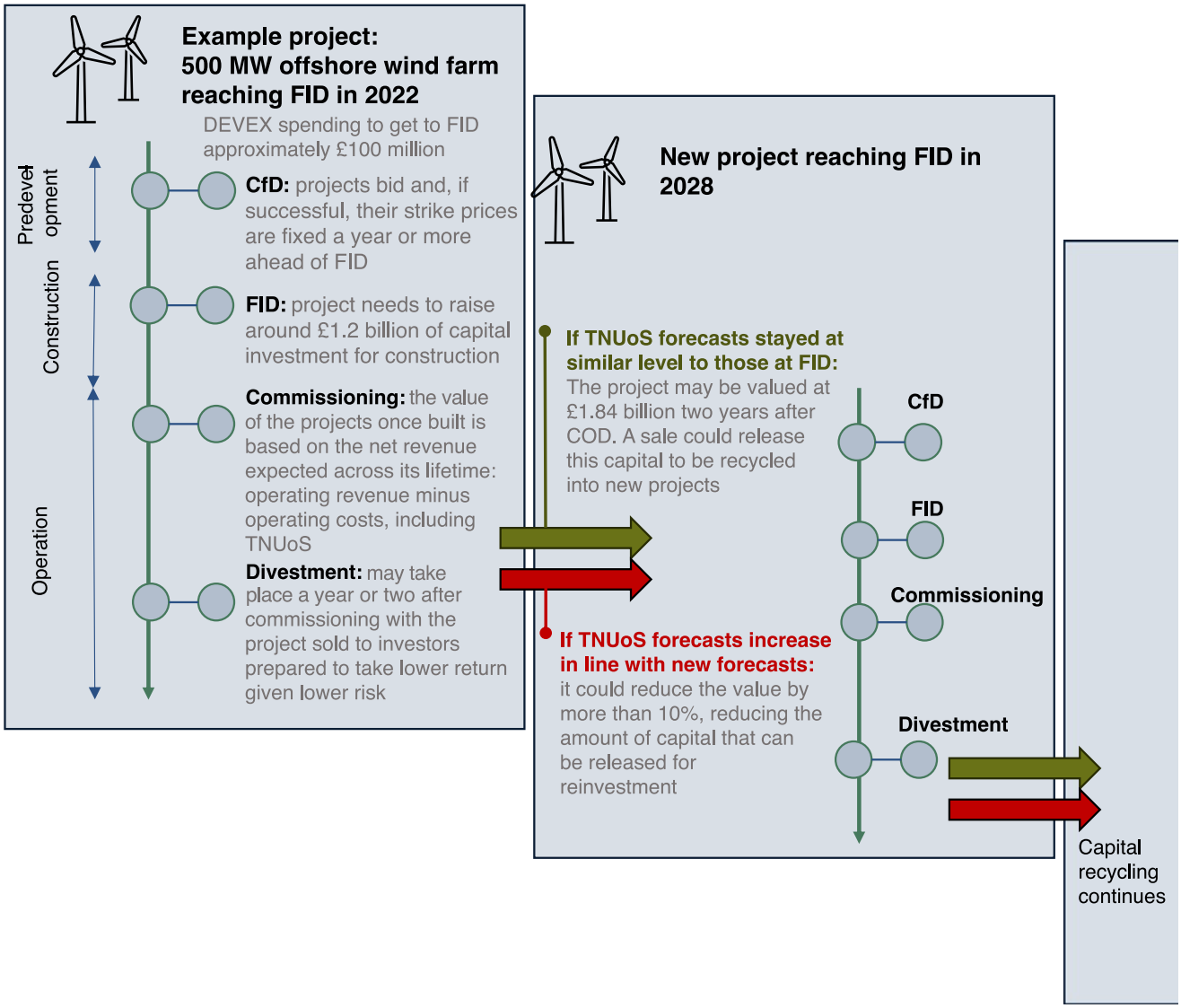

Figure 8: The investment cycle: development-investors tend to take out their investment once operation begins and recycle it into the next generation of projects. In a positive investment environment this can continue through several cycles across the timeline of the energy transition (Source: TEL analysis)

Beyond the direct impact on capital recycling, sustained and unexpected increases in TNUoS also risk damaging wider investor sentiment. Investors place a premium on regulatory stability and predictability, particularly for capital-intensive infrastructure with long asset lives. Where policy or regulatory frameworks are perceived to generate material, unmanageable downside risk after investment decisions have been made, this can weaken confidence in future investment, even where the underlying resource and strategic need are strong. It is critical that this is avoided in the Scottish investment climate.

The availability of capital is one of the binding constraints on delivering the transition. The scale of investment in new assets over the next decade represents a step change on that achieved in recent years, whilst the urgency of delivering that investment continues to grow. BVG Associates, on behalf of Scottish Renewables, estimate **an annual £4.6 billion of investment requirements for Scottish offshore wind**, whilst the UK Government in its Clean Power 2030 Action Plan put the **total investment needed this decade across GB at £40 billion a year** including £30 billion in new generation[12]. This investment must come from somewhere, and the reduction in available capital along with weaker investor confidence creates a significant risk.

Locational TNUoS is bad for consumers

The interaction between TNUoS and CfDs is increasingly influential in determining outcomes for consumers. Even where design choices for each scheme can be justified in isolation, their interaction shapes investor bidding behaviour and has direct implications for consumer bills.

Clearing up the CfD auction

New renewable projects rely on CfD support to stabilise revenue over time and high TNUoS has a direct effect on strike prices. Projects bid at a level that allows them to cover their full costs. Today, TNUoS is a significant contributor to the cost of energy for northern projects. In 2015, charges for a wind farm in the north of Scotland added £3.73/MWh to the Levelised Cost of Energy (LCoE). That has nearly doubled today and will more than double again by the end of the decade to more than £14/MWh (Figure 9).

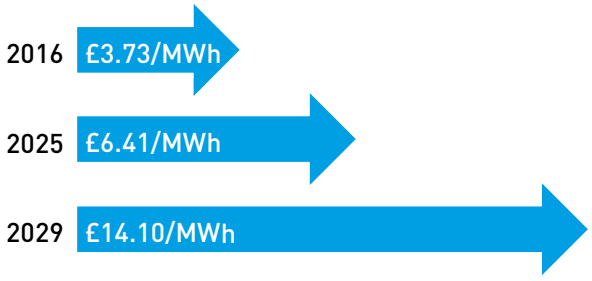

Figure 9: Contribution of TNUoS to the LCoE for a wind farm in northern Scotland (Source: NESO and TEL analysis[13])

High and uncertain TNUoS has a double impact in CfD bidding. First, generators facing higher TNUoS will submit higher bids reflective of those expected costs.

Where these projects are successful in CfD auctions they will often set the clearing price because TNUoS represents one of the biggest variables in cost between projects meaning that elevated TNUoS feeds directly into higher clearing prices, increasing costs for all consumers. Second, uncertainty over the future trajectory of TNUoS increases the cost risk for the project, which in turn will raise the cost of capital, a major driver of overall project costs, and further inflate CfD bids.

The UK Government has already recognised both effects. The first has been addressed by changes to CfD auction design, including the introduction of separate clearing prices for Scottish and non-Scottish offshore wind, intended to decouple Scottish CfD bids from the strike prices received by generators across the rest of GB.

The most recent TNUoS forecast issued by NESO in 2025 shows that this is no longer an issue only between Scotland and the rest of GB but is likely to be more important within Scotland. As shown in Figure 4, by 2030 the variation in TNUoS within Scotland will be larger than it is today across the whole of GB.

The second effect is reflected in assumptions used to set administrative strike prices. In AR6, Government increased assumed hurdle rates to reflect higher perceived risk, including an additional two percent risk premium for offshore wind and one percent for onshore wind, explicitly linked to TNUoS uncertainty. These uplifts have since been absorbed into the generally higher hurdle rate assumptions applied in AR7.

Despite these interventions, TNUoS will continue to deliver poor outcomes for consumers for as long as the current approach to TNUoS remains in place.

Investment effects

TNUoS also creates a significant headwind for new investment. Most projects rely on both equity and debt investors and although they approach risk differently, both groups will think carefully about their response to the scale and volatility of future TNUoS.

Equity investors need projected returns to meet their hurdle rates. If rising TNUoS pushes returns below these thresholds, investors will take their capital elsewhere. Uncertainty is also damaging. Not knowing how high TNUoS could rise adds risk, which in turn raises the required cost of capital and puts further upward pressure on CfD strike prices.

Banks take a different perspective. They provide debt at fixed interest rates and focus on downside risks that could impair a project's ability to service its loans.

As those risks increase, banks could reduce the amount they are willing to lend or tighten lending terms. This feeds through to a further impact on equity investors by increasing the proportion of equity required in the capital structure, reducing gearing and, in turn, lowering expected equity returns (Figure 10).

To date, TNUoS has not had a material impact on the availability of debt finance. However, the forecast doubling of charges this decade, combined with significant uncertainty over how TNUoS will evolve beyond 2030, may begin to raise concerns among lenders. If it does, it risks crowding out debt-financed projects in favour of a narrow set of organisations with balance sheets large enough to fund projects independently. This would reduce competition and further limit the diversity and scale of capital available.

It is important to recognise that when deteriorating investment conditions coincide with increasingly ambitious strategic plans for renewable deployment, there is a real risk of poor outcomes for consumers. Either the planned renewable capacity is not delivered and consumers miss out on lower wholesale prices, greater price stability and improved energy security. Or that capacity is delivered at higher than necessary cost, with consumers paying to cover investors and developers for the additional risk and uncertainty they face.

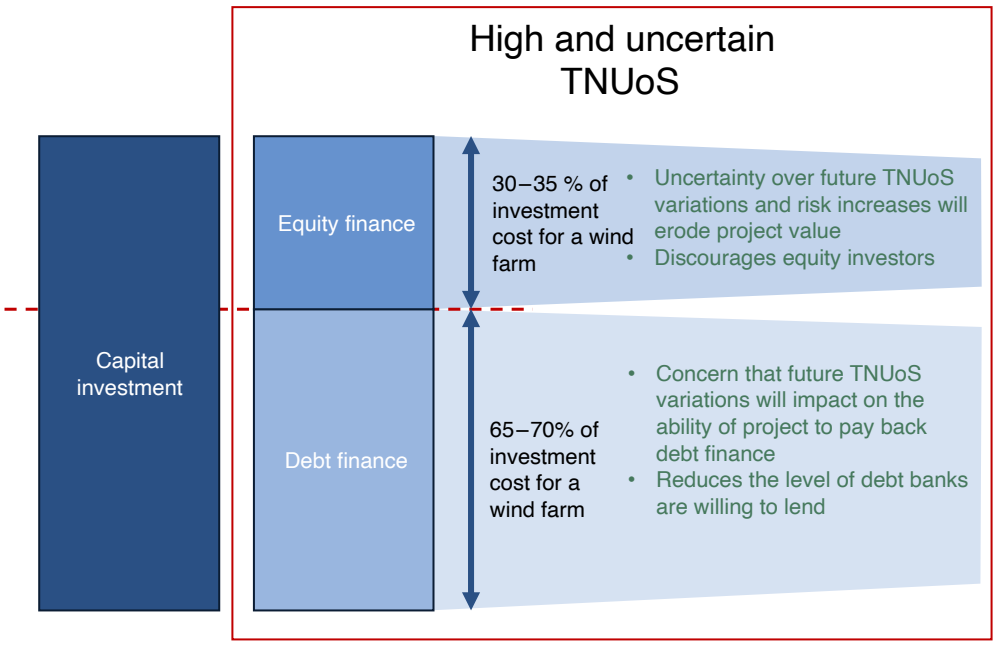

Figure 10: The appetite of both debt and equity investors could reduce due to the unprecedented increase and uncertainty in future TNUoS charges (source: TEL analysis).

TNUoS increases are exacerbated by other headwinds

TNUoS is only one of several headwinds facing Scottish generators. Transmission Loss Multipliers (TLMs) have become a significant additional penalty, supply chain pressures are intensifying and, while Clean Power 2030 is intended to accelerate renewable deployment, the limited focus on near-term demand growth raises serious concerns about the balance of renewable supply and demand.

Transmission Loss Multipliers

Transferring electricity across the transmission network inevitably results in losses and TLMs are used to account for these by adjusting a generator's metered output to reflect its contribution to transmission losses. In 2018, a locational element was introduced to TLMs in an attempt to make this approach more cost-reflective.

Since their introduction, the effect of the locational element for Scottish generators has become increasingly adverse. For example, during winter months the locational element for Northern Scotland has shifted from around *minus* 2% in 2018 to close to minus 5% in 2024. In practice, this means a generator in the north of Scotland may only be able to sell the equivalent of 95% of the electricity it produces. By contrast, the locational element of TLMs in South Wales is plus 2%, allowing generators to sell the equivalent of 102% of their output[14] (Figure 11).

The current approach to losses suffers from many of the same weaknesses as TNUoS:

- The methodology is complex and lacks transparency. **A modelling error earlier this year** resulted in a sharp and unexplained change that took several months to identify and correct.
- Future TLMs are impossible to forecast. This problem is even more acute than for TNUoS, as there are no official forward projections, and the underlying model has not been made available to industry. As a result, locational TLMs fail to provide a meaningful investment signal while still imposing material and uncertain financial impacts on projects.
- As with TNUoS, unpredictable changes in TLMs create windfall losses that erode asset values without improving system outcomes.

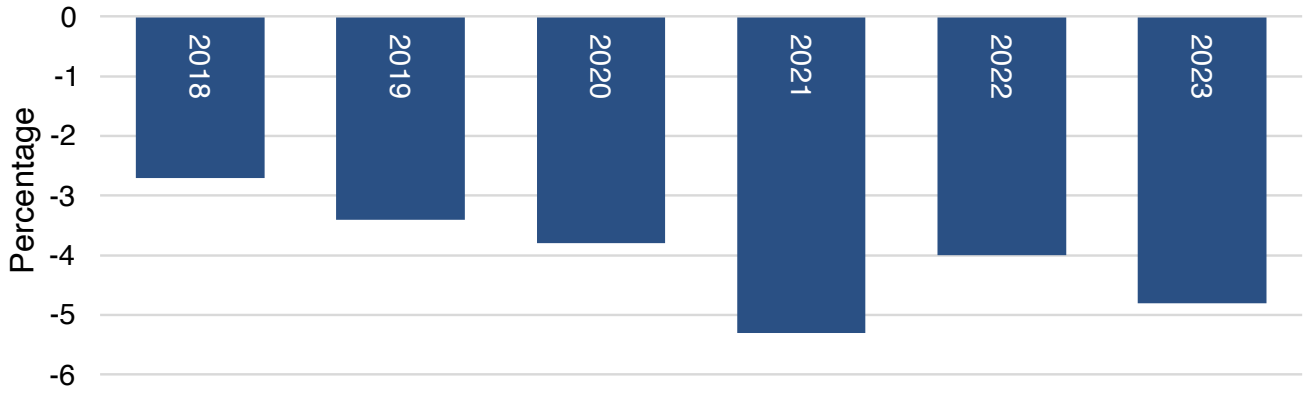

Figure 11: North of Scotland TLMs for winter months since the introduction of locational transmission loss allocation (Source: Elexon[15])

Supply chain and support infrastructure

Another headwind to add to the deteriorating TNUoS situation is a more challenging supply chain. Since the pandemic, supply chain pressures have had an increasingly material impact on generation development across all technologies. In particular, costs and lead times for high voltage equipment such as transformers have increased significantly and wind turbines have also seen sustained cost increases.

These pressures are reflected in delays to projects awarded from AR4 onwards, where unexpected cost increases and component delays have slowed delivery and, in some cases, undermined project viability.

More broadly, weaknesses in enabling infrastructure continue to delay progress. Long lead times for grid connections remain a binding constraint across technologies, despite recent reforms. In the offshore sector, additional bottlenecks have emerged, including insufficient port capacity and limited access to installation vessels, factors that will be particularly important as floating offshore wind moves beyond demonstration scale.

Future market uncertainty

New investment requires revenue certainty, whether delivered through market trading or support mechanisms. Some steps have been taken to improve this, such as the move from 15- to 20-year CfD contracts in AR7. However, significant sources of uncertainty remain, and the risks associated with them are growing.

In particular, the current focus on accelerating renewable generation capacity has not been matched by comparable progress in increasing electricity demand in the near term. Demand growth is likely to materialise later, while by the early 2030s the system may face frequent periods of renewable oversupply, where wind and solar output exceed available demand and flexibility. **This creates a real risk of economic curtailment**, with generators unable to sell their output. Importantly, this risk exists even for projects supported by CfDs.

Policy and legislative uncertainty further compound these challenges. After more than three years, the Review of Electricity Market Arrangements (REMA) has failed to provide clear answers to key reform questions. The process settled on a Reformed National Pricing (RNP) wholesale market, while leaving many critical design decisions unresolved[16]. Prolonged debate over locational pricing has crowded out progress on other critical issues, including the future design of low-carbon support, the capacity market and security of supply arrangements.

Implementation of the RNP programme is not expected until 2029. While reform of TNUoS, alongside the development of other mechanisms capable of providing locational signals, will be critical, as of early 2026 there is little clarity on the principles that will govern these reforms. This lack of certainty risks undermining investor confidence in projects approaching their investment decision, even where contracts have been awarded in recent CfD auctions. Without urgent action, projects may continue to struggle to secure finance even where holding a CfD. It will also be important to ensure competitive bidding in AR8.

Compounding risks and a narrowing window for delivery

Rising and unpredictable TNUoS charges would present a serious challenge in their own right. However, their impact is being significantly amplified by a wider set of pressures. Together, these factors compound the risks faced by Scottish generators, further undermining investor confidence, restricting access to capital and increasing the likelihood that projects struggle to progress despite strong policy ambition and contractual support.

TNUoS creates a risk of early closure

The continued rise in TNUoS not only undermines future investment but also creates a growing risk of premature closure for some existing generators, where operational costs could exceed operating revenues. This would slow progress on decarbonising the electricity system and damage investor confidence.

Offshore wind projects are especially exposed. In addition to rising onshore TNUoS charges, they must also recover the costs of offshore transmission assets through a separate charging component, significantly increasing their annual fixed cost base. As a result, some projects face the prospect of an annual operating loss despite having low marginal costs and continuing to deliver valuable generation to the system.

The same risk could apply to onshore wind farms soon to reach the end of their Renewable Obligation support. These early wind farms often have uncurtailed load factors of around 25 percent and lower revenue streams compared with modern offshore developments. Whilst there is some reduction in TNUoS as annual output reduces, charges for these generators will represent a higher percentage of annual revenue compared with those with higher load factors.

Dispatchable generators, essential for system security during periods of low wind and solar output, could also be at risk. As renewable capacity expands, these plants will run for fewer hours each year, reducing operating revenues whilst TNUoS charges could remain high.

Figure 12 shows illustrative cash flows for offshore and onshore wind farm examples. The offshore case, based on forecast 2029/30 TNUoS charges for a project connected in North Scotland, illustrates a project where the annual costs associated with the offshore transmission link are around £23.5 million, consistent with those of existing wind farms. When combined with zonal TNUoS charges and typical operation and maintenance costs, the project would operate at a loss despite receiving both market revenue and CfD top-up payments based on an AR4 strike price of £54 / MWh in 2025 prices. The onshore example shows how a similar outcome could arise for a merchant wind farm following the end of its ROC support with an ongoing fixed price PPA at £50 / MWh.

Sustained pressure on operating margins could prompt owners to consider repowering earlier than is economically or technically optimal, potentially to secure a new CfD. While repowering can deliver efficiency gains, doing so prematurely risks diverting capital and supply chain capacity away from the delivery of new generation that is required to meet system targets alongside existing wind farms.

Finally, these examples do not capture other growing pressures on project viability, including economic curtailment, adverse TLMs and rising operation and maintenance costs. Taken together, these factors materially increase the risk of inefficient early closure of assets that the system still needs.

If operators were forced to close projects it would be seen as a failure of regulation to deliver on the ambitions of the transition and would considerably damage investor confidence, affecting investments in future projects.

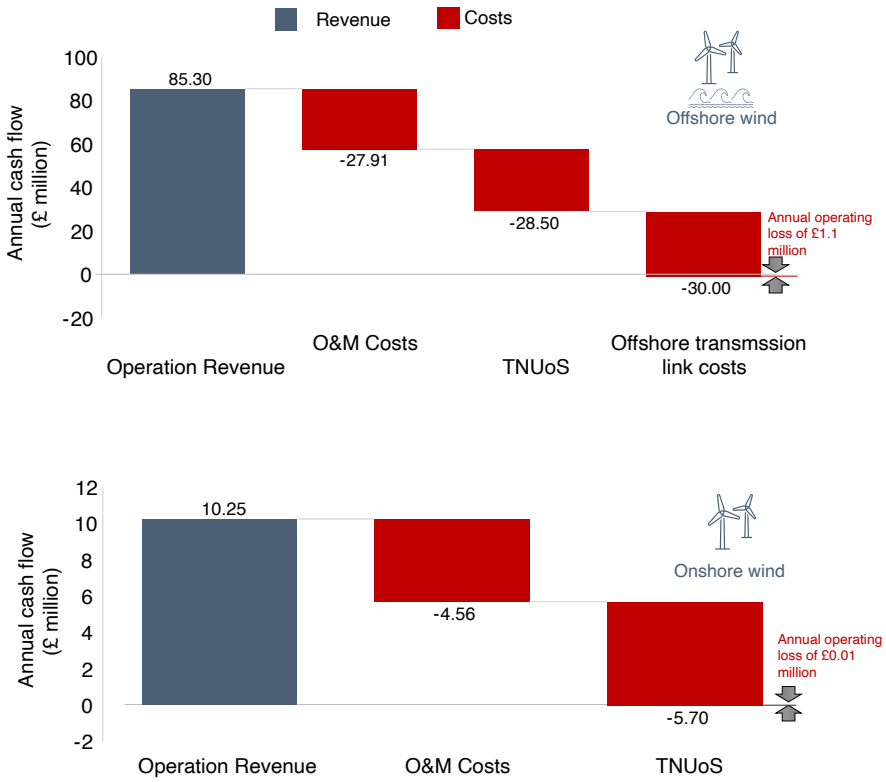

Figure 12: Annual operating profit / loss for two Scottish wind farms: offshore (top) and onshore (bottom). TNUoS charges are based on 2029 forecast in Northeast Scotland (Source: TEL analysis[17])

Today's TNUoS principles don't support strategic planning

It is now widely accepted that a strategic approach is needed to develop a secure, decarbonised GB electricity system. NESO is preparing the first Strategic Spatial Energy Plan (SSEP), due for publication in 2027, with the Centralised Strategic Network Plan (CSNP) expected to follow a year later. Together, these plans will set out the intended geographical distribution of generation and network assets needed across the country.

However, the SSEP and CSNP, on their own, do little more than define a pathway. Delivering that pathway will require a coordinated set of market, policy and regulatory levers that actively support implementation of the plan. Reform of TNUoS must be one of those levers. At present, TNUoS works against the strategic plan by discouraging investment in generation in locations where the plan indicates it is most needed and it does so at higher cost to consumers. These tensions are already visible in the interaction between the current charging regime and the UK Government's Clean Power 2030 Action Plan.

TNUoS creates a strong disincentive to invest in generation in Scotland, undermining rather than supporting the delivery of Clean Power 2030.

There are four key reasons why TNUoS does not support the strategic plan:

- It sends locational signals that run counter to the requirements of the plan.
- Transmission network development is now being driven by the strategic planning process itself, through initiatives such as Clean Power 2030. This removes one of the original justifications for locational TNUoS: that network investment follows generator decisions.
  It creates uncertainty and volatility that affect asset values and investment decisions, increases the cost of capital and pushes up CfD strike prices across the system.
- Existing generators, which cannot respond to changing TNUoS signals, are penalised, damaging investor confidence and eroding value that could otherwise be recycled into new projects.

Over the next six months, it is vital that the UK Government provides clarity on how they intend to ensure the SSEP is delivered. This requires setting out the principles that will guide decision making, the levers they will use and the enduring role of TNUoS.

Ofgem has already recognised the need for significant reform for TNUoS as part of the strategic planning and RNP process. It has confirmed that it is exploring how to incentivise generation to locate in areas where transmission network capacity is planned and ensure new network is used efficiently.

Achieving this needs a very different approach to the one embodied by the existing TNUoS principles. It is a shift that needs to be pursued with urgency.

Recommendations

ACTION NOW: REFORMING TNUOS

Reforming TNUoS is now essential. The current system has become a barrier to our ambitions to decarbonise and deliver a just transition. TNUoS is now a brake on capital flows, a growing risk for investors and, in some cases, a potential reason for early closure. Reforms need to include urgent, practical steps to stabilise charges for existing projects and those approaching final investment, alongside a longer-term review of how TNUoS should operate in a strategically planned energy system.

Action 1: Fix charges for existing projects at levels prevailing at the point of their original CfD bid

Existing generators should have their TNUoS charges fixed in real terms at the level prevailing when the project submitted its bid into a CfD auction or made a final investment decision. This will remove cost increases that erode project value and reduce the risk of early asset closure, particularly for assets that remain critical to the transition. Importantly, it would protect project value and release additional capital for reinvestment in new projects, while also rebuilding investor confidence following recent and significant changes in TNUoS forecasts.

Action 2: Fix charges for new projects

Similarly, new projects should receive a fixed TNUoS real terms charge at the level prevailing at the time each project bids into a CfD contract. Similar arrangements should be put in place for other technologies which use different support mechanisms, or which invest purely on a merchant basis. This will give investors and lenders the certainty they need to commit capital and maintain the pipeline of new development.

Action 3: Undertake a fundamental review

Alongside these immediate measures, Government, Ofgem and NESO should launch a fundamental review of how transmission costs are recovered. That review should ensure that the TNUoS framework supports, rather than undermines, the SSEP and the wider strategy for a decarbonised and secure electricity system. And it should ensure that all users of the transmission system contribute to network costs.

THE PRIZE

Reforming TNUoS is not about protecting investor profits. It is about delivering tangible benefits for consumers, while turning transmission charging into an enabler rather than a blocker of decarbonisation, energy security and a just transition. By creating a stable and predictable framework, reform can lower financing costs, reduce risk premiums embedded in CfD bids and ultimately put downward pressure on consumer bills.

A fair and strategic approach to transmission charging would support capital recycling, safeguard existing low-carbon capacity and unlock the investment needed to deliver clean, secure electricity at least cost. Crucially, it would recognise the strategic role Scottish generation must play in the GB transition and create a charging framework which supports delivery.

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