Email to:
tnuosreform@ofgem.gov.uk

12 November 2021

To whom it may concern,

Call For Evidence – Transmission Network Use of System Charges

Scottish Renewables is the voice of Scotland's renewable energy industry. The sectors we represent deliver investment, jobs, social benefits and reduce the carbon emissions which cause climate change. Our members work across all renewable energy technologies, in Scotland, the UK, Europe and around the world. In representing them, we aim to lead and inform the debate on how the growth of renewable energy can help sustainably heat and power Scotland's homes and businesses.

Scottish Renewables welcomes the opportunity to provide written evidence to Ofgem into the call for evidence on Transmission Network Use of System Charges (TNUoS).

TNUoS is no longer fit for purpose to meet either The Scottish Government or UK Government's net-zero climate targets. This charging mechanism is a significant barrier for the deployment of renewable generators in the UK, particularly in northern UK areas, where most of the onshore and offshore wind resource is located.

Today, the UK has one of the highest locational charges in Europe and it is one of the few countries that charges a locational element for transmission charges. This is putting UK generators, particularly in Scotland, at a disadvantage to European generators which today do not pay for using the Great Britain transmission System at all[1].

Scottish Renewables believes that the need for TNUoS reform is more urgent than ever as we seek to deploy large levels of renewable technology to tackle the climate emergency.

In responding to this consultation, we would like to draw your attention to the following points:

- It is essential that there is a wider reform of TNUoS to meet the following criteria: Net zero alignment, stability and predictability, cost-reflectivity and recognition of geographic diversity of renewables.
- The main elements of TNUoS methodology that are driving the current disparity on locational charges are in the wider tariff, specifically in the Year Round Shared and Year Round Not Shared elements. Therefore, a review of these elements is critical as they are the factors that are driving volatility and leading to the misalignment with net-zero.
- The use of multipliers can help to mitigate volatility and the disparity on locational charges. Multipliers could also lead to a more cost reflective regime.

[1] RIDG (May 2021), Charging the wrong way. Available:
https://cdn.ymaws.com/www.renewableuk.com/resource/resmgr/210524_tnuos_paper_final_for.pdf

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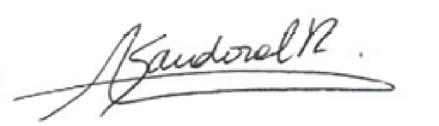
- A task force approach would be the best vehicle for change to carry out this reform. We also suggest this reform be led by Ofgem and the Department for Business, Energy and Industrial Strategy (BEIS), as this will require strong leadership from a suitable body with expertise of network charging and commercial awareness to meet government ambitions.

- Flexibility will become increasingly important as we move to a renewable-based energy system. Hence, we consider that the flexibility and locational benefits of storage, particularly Large Scale and Long Duration Storage (LLES), should specifically be taken into account in the design of transmission charges, recognising and thereby incentivising the value that these assets provide.

- A suitable timeline for reform should be between 2 and 3 years in line with the OTNR.

Scottish Renewables would be keen to engage further with this agenda and would be happy to discuss our response in more detail.

Yours sincerely,



Angeles Sandoval
Policy Manager | Networks & Markets
Scottish Renewables

1. The extent to which a broader review of TNUoS would be beneficial.

Back in 1992, the charging system was designed to provide clear signals to the energy market to incentivise developers to build fossil fuel power stations close to demand. Today, as we move to a smart, decentralised and renewables dominated energy system, this charging design is no longer fit for purpose and an updated system which balances the strengths of different parts of the UK is needed.

We believe that TNUoS requires an extensive reform that should meet the following criteria: Net zero alignment, stability and predictability, cost-reflectivity and recognition of geographic diversity of renewables.

1.1 Net zero alignment

The current TNUoS charging mechanisms are a significant barrier to market for renewable generators in the UK, particularly in northern UK areas and as such represents an issue to be tackled to better enable The Scottish Government and UK Government's net-zero climate targets.

This regime is leading to disproportionate charges by location that are damaging the deployment of the renewable technologies needed to deliver on legally binding net-zero targets. Scottish Renewables believe that there is a strong case to review the transmission charging methodology to ensure that the development of renewables is not discouraged where resources are most abundant. The need for review is even more pronounced given the ongoing review and reform of the offshore transmission arrangements.

To achieve the UK net-zero targets, we need a steep increase in renewable energy installation by 2050. According to the Climate Change Committee (CCC) in the Sixth Carbon Budget[2], renewable deployment by 2050 should be between 95GW and 125GW for offshore wind, between 75GW and 85GW for solar PV, and between 30GW and 35GW for onshore wind. This is a dramatic increase in renewable deployment; therefore, we would expect that regulation moves forward at pace to facilitate the deployment of renewables across the whole UK and should not constrain this in any way.

TNUoS is designed to encourage generation to be located close to demand, however, to reach the level of renewable deployment required by 2050, we will need technologies to be located across the whole of the UK where the renewable resource is available. Additionally, the location of renewable generation is decided early in the development process, normally before the 5-year TNUoS forecast. Therefore, it is questionable whether TNUoS provides a useful signal at the point of choosing a location.

The locational factor becomes more pronounced when we analyse this by technology. According to the 2021 FES report[3], in the consumer transformation scenario, we will need 44GW of onshore wind by 2050, which in terms of resource is mostly expected to be deployed in Scotland. However, current TNUoS charges are disproportionally large in Scotland, which is reducing Scottish renewable deployment and our ability to deploy commercially viable projects at scale. This problem will not be solved with more onshore wind deployment in southern Great Britain due to considerable planning barriers and low load factors in those areas.

Furthermore, we note that the southern North Sea is becoming increasingly congested, with offshore wind projects seeking space to operate alongside many other users with recent development announcements targeting northern areas of the North Sea off the coast of Scotland. Similarly, land for large scale solar energy sites in the south of England is becoming progressively more difficult to find. Overall, Scotland's renewable resource will become more important to supply the energy we will need to meet our climate

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[2] Climate Change Committee, (2020). The sixth Carbon Budget. Available https://www.theccc.org.uk/publication/sixth-carbon-budget/

[3] National Grid ESO. Future Energy Scenarios (2021). Available: Future Energy Scenarios 2021 | National Grid ESO

targets, but the current charging regime is constraining deployment in those areas, making the task very difficult to achieve.

With regards to offshore wind, we note that TNUoS is making Scottish projects less competitive in recent Contract for Difference (CfD) allocation rounds, as it is not a cost that developers can control. From the auction rounds AR1[4], AR2[5] and AR3[6] results available through BEIS website (see table below), it is possible to see that the capacity awarded to offshore wind Scottish projects has decreased from 39 % in AR1 to 9% in AR3.

Auction Round	**Total offshore wind capacity awarded (MW)**	**Capacity of offshore wind Scottish projects (MW)**	**% Capacity awarded to Scottish projects**
AR1	1162	448	**39%**
AR2	3196	950	**30%**
AR3	5466	466	**9%**

With respect to AR3, we would note that several Scottish projects that were ready to build were unsuccessful in winning contracts. These include the 90-turbine Moray West Offshore Wind Farm (sister project to the Moray East wind project) the Inch Cape Wind Farm off the Angus coast. Similarly, several other remote island wind projects were also unsuccessful, such as the Viking Wind Farm joint venture between the Shetland community and SSE. These projects are located in areas of high wind resource but face TNUoS charges that make them struggle to compete despite offering high load factors.

This situation is expected to become worse without any action. According to National Grid ESO tariffs[7], TNUoS charges in the North of Scotland have increased from 11 £/kW in 2016 to 26.35 £/kW in 2021. By comparison, TNUoS 'credits' (negative payments) are received by equivalent generators in southern Great Britain for their use of the connection to Great Britain electricity market.

It is Scottish Renewables' view that this fact alone illustrates how locational charges are actively market distorting. The locational bias in the TNUoS zonal charging methodology is considered to be at odds with other policy commitments, most notably the UK's net-zero ambitions.

Ofgem needs to consider the wider policy environment, including delivering net-zero in its charging design, and also providing a simpler charging regime that can be relied on by generators and demand users in long term forecasting of project costs to enable commitment to projects by removing a key cost uncertainty.

Finally, we would note that a recent report by RIDG[8] showed that the **UK has among the highest locational charges in Europe**; indeed, **one of the few countries that charges a locational element for transmission charges**. This is putting UK generators, in Scotland in particular, at a disadvantage to European generators. As we become more interconnected with Europe, the TNUoS methodology is incentivising the system operator to import (potentially more carbon intensive) power over the interconnectors, at the cost of lower deployment of renewable generation in Great Britain, and increasing reliance on the interconnectors for security of supply.

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[4] Contracts for Difference (CFD) Allocation Round One Outcome - GOV.UK (www.gov.uk)
[5] Contracts for Difference (CFD) Second Allocation Round Results - GOV.UK (www.gov.uk)
[6] Contracts for Difference (CfD) Allocation Round 3: results - GOV.UK (www.gov.uk)
[7] National Grid ESO (2021). 2021 tariffs. Available https://www.nationalgrideso.com/charging/transmission-network-use-system-tnuos-charges
[8] RIDG (May 2021), Charging the wrong way. Available: https://cdn.ymaws.com/www.renewableuk.com/resource/resmgr/210524_tnuos_paper_final_for.pdf

1.2 Stability and predictability

TNUoS charges are intended to provide an efficient price signal to generators. However, TNUoS volatility sends an inefficient signal for developers and investors, increasing the capital cost of projects that will ultimately cost energy consumers more. According to a report conducted by NERA consulting, consumers could face costs between £122 million and £391 million per year by 2030, if finance risk for future wind project resulting from TNUoS is not addressed[9].

The latest National Grid ESO forecasts do not reflect the impacts of the planned increases in grid connection between Scotland and northern England. Also, the lack of long-term forecasting available to projects in advance of 25–50-year project commitments present a major barrier to investment in UK renewable projects, particularly further North as the locational charges increase, and the volatility seen in such (as discussed further below) causes significant operational cost differentials year on year over which the generator has no control.

Presently forecasts produced by National Grid ESO look no further than 5 years ahead, due to the complex charging calculation methodology and its inherent sensitivities to multiple inputs. Scottish Renewables believes it is time for a simpler methodology that provides long term certainty to all involved stakeholders, and is better aligned with the UK's net-zero ambitions.

TNUoS charges represent a large proportion of the operational costs of renewable generation. While TNUoS charges are only 2% of the operating costs of a combined cycle gas plant, they are around 30% of the operational cost for renewable generation[10]. Hence, volatility is not a minor risk for renewable generators.

In research conducted by SSEN Transmission they found[11]:

- Generators see swings in their TNUoS charges, typically over 50% up or down each year.
- Charges are unpredictable – Using National Grid's own data, the average forecast error under-estimated the actual charge by one third.

This volatility is in sharp contrast to the total revenue allowed of the Transmission Owners (TOs) that TNUoS charges are established to recover between both generation TNUoS and demand TNUoS. The cumulative allowed revenue of NGET, SPEN and SSEN Transmission has been stable, within 5% of £2.5 billion, over the past five years.

Investors need cost certainty and clear, forecastable TNUoS when planning and delivering long-term investments at lowest cost of the UK consumer. We also note that price volatility is a significant challenge for operational sites, where projects have been built and financed at a specific point in time based on the best available view of TNUoS at that time.

Once final investment decision has been taken, these projects cannot react to changes in locational signals and therefore volatility in TNUoS costs simply adds risk to the projects. Volatility and unpredictability are not unique to Scotland but experienced by all generators regardless of technology or location. This

[9] NERA Consulting (2021). Quantifying the Risk of TNUoS Charge Volatility for Wind Developers

[10] NERA Consulting (2021). Quantifying the Risk of TNUoS Charge Volatility for Wind Developers

[11] SSEN, Transmission (Sept 2021). Offshore Wind Transmission Charges. Available: https://www.ssen-transmission.co.uk/media/5764/ssen-transmission-offshore-tnuos-addendum_.pdf

uncertainty leads to increasing risk margins for developers, ultimately increasing costs that will be passed onto consumers.

The issues mentioned previously become particularly important given the scale of investment in wind generation expected to meet the 40GW of offshore wind target by 2030. Offshore wind not only faces high swings associated with the locational factor in the TNUoS methodology, but also faces high costs associated with the local circuit tariff, which today can be up to 48 £/KW.

According to further research[12] conducted by SSEN, they found that:

- There is no apparent value in the locational 'signal' to offshore wind farm developers
- The lead time for offshore wind farm development is such that investment decisions and CfD bidding are made without confidence in future transmission use of system charges
- There are demonstrable impacts of transmission charge unpredictability and volatility on offshore wind farm costs and, hence, the cost to energy consumers.

In addition to all the above, we would like to note that in the last year, changes to the expansion constant would have increased TNUoS charges by as much as 80% (through CMP 315) in northern zones if Ofgem had not agreed to stabilise this (through CMP375) at short notice. These code modifications are still under review, and it only illustrates the challenges and uncertainty that developers face with the instability of the charging regime.

Volatility and unpredictability of TNUoS are significant issues for renewable generators today, so we believe that the charging regime requires quick fixes to address these issues urgently.

1.3 Cost-reflectivity

In the recent 'Access and Forward-looking Charges Significant Code Review: Consultation on Minded to Positions' Ofgem published alongside the consultation a quantitative analysis carried by CEPA-TNEI[13]. This analysis shows the charges that small distributor generators would face if they paid TNUoS charges up to 2040 (see table below).

The table shows the disparity of charges by location, which is the same issue we have exposed previously at transmission level. We can see a strong signal to incentivise fossil-fuel generation anywhere in England or Wales, and even to pay TNUoS credits to fossil-fuel generation throughout Scotland, despite the principles which TNUoS was designed to deliver.

On the other hand, the only generation making payments for wider TNUoS is low carbon conventional and variable renewables in Scotland alone (zone 1 and 2). These outcomes are hard to reconcile against cost-reflectivity, nor against reasonable regulatory uncertainty for existing generators.

Above all, these outcomes are hard to reconcile with the deployment of variable renewables required to meet net-zero pathways.

[12] SSEN, Transmission (Sept 2021). Offshore Wind Transmission Charges. Available: https://www.ssen-transmission.co.uk/media/5764/ssen-transmission-offshore-tnuos-addendum_.pdf

[13] Ofgem, Access & Forward-Looking Charges SCR Minded-To Publication (Jul 2021) – document (3) CEPA TNEI Quantitative analysis, page 29 table 5.3. Available: https://www.ofgem.gov.uk/publications/access-and-forward-looking-charges-significant-code-review-consultation-minded-positions

Table 1: 2040 Forecast charges for Small Distributor Generators.

Dist. zone	Capacity charge £/kW, Conventional generators	Capacity charge £/kW, Low Carbon generators	Capacity charge £/kW, Intermittent generators
1	-3.56	54.02	54.46
2	-5.72	29.17	29.91
3	-7.67	-0.24	-0.17
4	-8.32	-4.55	-4.26
5	-8.97	-8.86	-8.35
6	-8.97	-8.86	-8.35
7	-13.55	-18.44	-13.86
8	-13.55	-18.44	-13.86
9	-13.17	-16.37	-12.04
10	-13.55	-18.44	-13.86
11	-14.69	-19.48	-13.74
12	-13.55	-18.44	-13.86
13	-14.69	-19.48	-13.74
14	-14.69	-19.48	-13.74

Ofgem July 2021 - Access & Forward Looking Charges SCR Minded-To Publication - document (3) CEPA-TNEI Quantitative Analysis, page 29 Table 5.3

We are aware that this forecast illustrates the charges that small distributor generators would face if they paid TNUoS charges which is not the case yet. However, we believe that this is a fair representation of the current regime at transmission level and is strong evidence to review the cost reflectivity of the current regime.

When we analysed cost-reflectivity at the voltage level we found further distortions. Today, while generators connected at 132 KV lines in Scotland are classified as transmission connected, in England and Wales they are considered as distribution connected. This leads to significant differentials:

- Generators in Scotland pay transmission network charges while those in England and Wales either receive credits under the Embedded Export Tariff (in the South) or pay no charge
- Generators in England and Wales pay distribution network charges
- Generators in Scotland are required to pay balancing services charges while those in England and Wales are not, although this may change from ~2023/24 onwards following the outcome of the 2nd balancing task force review.

Scottish Renewables recently commissioned research[14] with Cornwall Insight to look at these differentials in more detail. The modelling identified that the disparity in charges between England & Wales and Scotland are significant, being greatest for onshore wind, but still high for solar and hydro. The overall difference for a 40MW onshore wind site in Scotland was shown to be £1m higher than in England & Wales.

[14] Cornwall Insight (Jul 2021), Charging differentials for 132kv generation. Available: https://www.scottishrenewables.com/publications/924-report-charging-differentials-for-132kv-generation

The figure below illustrates this in more detail.

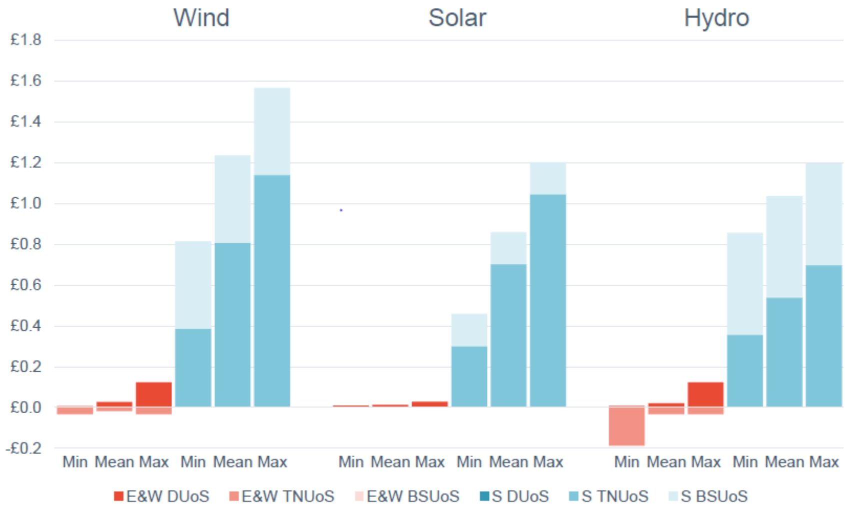


Figure 1: Cornwall Insight. Modelled network charges for 40MW 132kV wind, solar and hydro, 2021-22 (£mn)

Although ongoing regulatory reforms will remove some of the differentials, including:

- Removing the balancing service charges onto demand only, which would result in all 132kV generators not paying those charges from 2023-24.

The report shows that a significant differential remains, with the average charge in England and Wales in 2021-22 being around £500k lower than in Scotland when this reform is applied. This is predominantly due to transmission network charges, which have a very strong locational element.

We believe that this disproportionately disadvantages Scottish Users, a situation which is made worse under new arrangements in the positioning of the connection boundary proposed in the recent "Minded to Position consultation". Where Ofgem is proposing to recover the costs associated with transmission that are triggered by a distribution connection – in England & Wales this connection will receive no reinforcement cost signal whereas in Scotland the user will be liable for the full cost in advance for the 132kV substation reinforcement.

This distortion already exists but is made worse by the proposed change in connection boundary. Acknowledging the SHEPD and SPD "DG heat maps", it can be seen that a significant majority of 132kV "GSP[15]" substations across Scotland are close to or at their capacity to accommodate further generation, which means that this problem is substantial.

Additionally, if code modifications CMP315 and CMP375 progress unfavourably, charges for 132kV connected generators in Scotland will increase significantly more.

[15] Grid Supply Point – the substations where the transmission system and distribution networks meet

1.5 Recognition of geographic diversity of renewables

The current charging regime is designed to incentivise generators to locate close to the demand. In a fossil-fuel based system where fuel can be transported to generation sites, this makes some sense, in a renewables-based system where generation location is dictated by resource and site availability, it does not. The current system is incompatible with the decentralised energy system of the future that the UK Government envisioned in the 2020 Energy White Paper[16]. Regulation does not exist separate to policy. If the Government's preference is to increase and decentralise the deployment of cost-effective renewables and flexibility as a key element of achieving the net-zero target, regulatory processes and the charging regime must not constrain this.

The UK has diverse renewable resources that can be deployed across the whole country, with one of the best potentials for onshore and offshore wind. We believe that energy diversification is important to provide energy security and long-term sustainability transitions. Currently, solar PV is almost the only variable renewable technology which has good load factors close to highest areas of concentrated demand (south), which means that the current regime discriminates against other technologies that are driven by resources that are mostly located in the north of Great Britain.

We understand that most of the new solar resource is expected to be connected to distribution networks rather than to the transmission system, but we are also aware that Ofgem is considering the extension of the TNUoS regime to distribution level. Hence, we think that if future TNUoS reform is to be applied to distribution level as well, then it is important to consider the whole system effects of the reform and take this into account in any change proposed. Without TNUoS reform Scotland and the rest of the UK will not be able to achieve the envisioned energy diversity and fulfil the potential for a net-zero electricity system from UK resources.

We would like to highlight a recent report developed by Aurora Energy Research which analyses two possible scenarios for the deployment of wind energy[17]. The first scenario analyses the case in which wind capacity is built predominantly in regions with attractive load factors (Scotland and the North Sea). The second one analyses the scenario where more wind resource weighting is given to locational price signals (i.e. TNUoS) and planning requirements are assumed to be relaxed, resulting in lower wind buildout in Scotland in favour of the England and Wales. Overall, the results indicate that if the system is driven by the second scenario this would lead to a more volatile power system and require higher wind generating capacity in Great Britain to reach net-zero by 2050. These effects lead to changes in market prices, with potentially negative implications on power plant economics and consumer costs in the long term, counteracting benefits from the alleviation of grid congestion.

The key findings of a system driven by the second scenario are:

- The increase in volatility due to a more correlated wind fleet:
  - This leads to an **increase in wholesale price volatility**, with the spread between the 90th and 10th percentile prices reaching ~5% in the early 2040s, adding to the challenges of managing merchant risk exposure
  - **Wholesale capture prices for wind are slightly lower,** potentially **requiring higher CfD bids** to meet investor hurdle rates.
  - The **need for energy balancing also increases**, with net imbalance volumes increasing by ~3% in the mid- 2040s, alongside a small increase in imbalance prices, potentially **contributing to higher balancing costs for consumers and generators.**

[16] UK Government (2020). Energy white paper: Powering our net zero future. https://www.gov.uk/government/publications/energy-white-paper-powering-our-net-zero-future

[17] Aurora Research (2021). Impact analysis of different geographic distributions of wind generation in GB

- The network **will require 5-6 GW additional wind capacity in Great Britain to reach net-zero by 2050** which will need to be supported by a **faster buildout of battery storage**. These changes to the capacity mix could lead to higher Capacity Market prices in the long run, particularly from the late 2030s onwards, potentially contributing to **higher consumer bills**.

We note that northern areas of Scotland, Orkney in particular, experience challenges that are making projects unviable in that zone. Orkney is located outside the main interconnected transmission system (MITS) which means that transmission connected generators on the island are allocated in the wider TNUoS charge to the nearest transmission charging zone, plus a 'local spur' (a subsea link) charge for transmission to the islands. The combination of these two elements makes TNUoS charges in this location very high[18]. This area of Scotland has significant wind and marine renewable resource but uncertainty around TNUoS charges and policy outlined in recent publications such as the 'Access and Forward-looking Charges Significant Code Review: Consultation on Minded to Positions' are making projects unviable with little possibility to participate in the next CfD auction. These projects struggle to calculate suitable bids when the main variable in their business model is unclear and unpredictable. This is an issue not only experienced by northern areas of Scotland but is clearly more accentuated further north.

We believe that TNUoS reform must recognise the geographic diversity of renewables and the benefits of a diverse mix of generation alongside this. We have shown extensive evidence that demonstrates that the energy system from 2030 onwards will be driven by low carbon generation, so we believe that allowance for renewable resource location in the areas of high natural resource is something that should be recognised and addressed in this reform.

2. Priority areas for reform

2.1 Wider Tariff

Today, the wider tariff is the main element of the TNUoS methodology that is driving the current disparity on locational charges. The following extract from a report[19] by National Grid ESO shows the forecast of wider tariffs for 2022/23.

From this it is possible to see that the tariffs for intermittent technologies in the north of Scotland are extremely high compared to those in England and Wales. The North Scotland tariff (Zone 1) is around £25.53 /KW while West Devon and Cornwall tariff is around -£3.92/KW (a negative value being a TNUoS credit or income to the generator, rather than a liability).

Generators in

- zones 1-12 pay TNUoS of close to £10/kW or above (Zone 12 being Solway and Cheviot near the England-Scotland border),
- zones 13 and 14 have charges which are between £3.50 and £6.50 per kW,
- zones 15 to 19 are charged under £1 per kW,
- zone 24 are charged ~£1 per kW,
- the remaining 7 zones are all paid for their use of the Great Britain electricity system under the present TNUoS regime.

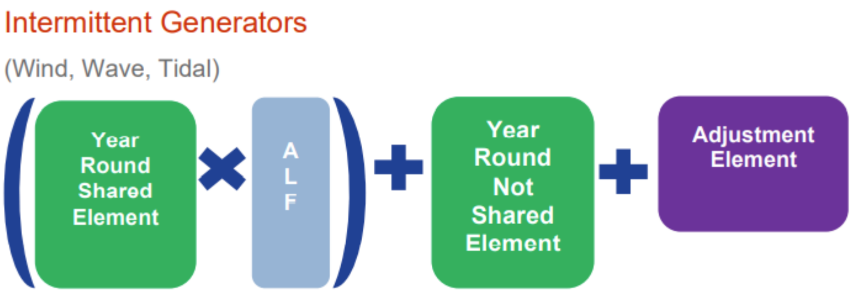
[18] GHD (May 2021). A Transmission Link for Orkney: an impact analysis on the Orkney Economy. Available: https://www.orkney.gov.uk/Files/Strategic_Projects/Orkney_%20Transmission_Link_Report_May_2021.pdf

[19] National Grid ESO (Aug 2021). Forecast TNUoS Tariffs for 2022/23. Available: https://www.nationalgrideso.com/document/207346/download

Table 2: National Grid ESO. Generation Wider Tariff[20] for 2022/23, p11.

Zone	Zone Name (Generation Tariffs)	System Peak Tariff (£/kW)	Shared Year Round Tariff (£/kW)	Not Shared Year Round Tariff (£/kW)	Adjustment Tariff (£/kW)	Conventional Carbon 40% Load Factor (£/kW)	Conventional Low Carbon 75% Load Factor (£/kW)	Intermittent 45% Load Factor (£/kW)
1	North Scotland	4.973915	19.232070	17.212447	-0.332681	19.219041	36.277734	25.534198
2	East Aberdeenshire	3.700890	10.426620	17.212447	-0.332681	14.423836	28.400621	21.571745
3	Western Highlands	4.373415	16.331816	15.897044	-0.332681	16.932278	32.186640	22.913680
4	Skye and Lochalsh	-0.143020	16.331816	17.699383	-0.332681	13.136779	29.472544	24.716019
5	Eastern Grampian and Tayside	5.274420	12.565477	13.483534	-0.332681	15.361343	27.849381	18.805318
6	Central Grampian	4.839171	12.952915	13.944847	-0.332681	15.265595	28.166023	19.440978
7	Argyll	3.304580	11.120894	19.326273	-0.332681	15.150766	30.638843	23.997994
8	The Trossachs	4.235801	11.120894	11.724202	-0.332681	13.041158	23.967993	16.395923
9	Stirlingshire and Fife	3.194131	10.423263	11.107616	-0.332681	11.473802	21.786513	15.465403
10	South West Scotlands	1.954041	10.444205	11.124421	-0.332681	10.248810	20.578935	15.491632
11	Lothian and Borders	4.153304	10.444205	6.471641	-0.332681	10.586961	18.125418	10.838852
12	Solway and Cheviot	2.239859	7.142460	6.411378	-0.332681	7.328713	13.675401	9.292804
13	North East England	4.299320	5.653251	4.161919	-0.332681	7.892707	12.368496	6.373201
14	North Lancashire and The Lakes	1.956689	5.653251	1.492934	-0.332681	4.482482	7.356880	3.704216
15	South Lancashire, Yorkshire and Humber	4.952681	2.066040	0.250363	-0.332681	5.546561	6.419893	0.847400
16	North Midlands and North Wales	3.757167	0.859620	-	-0.332681	3.768334	4.069201	0.054148
17	South Lincolnshire and North Norfolk	2.513410	0.740381	-	-0.332681	2.476881	2.736015	0.000490
18	Mid Wales and The Midlands	1.034379	1.909192	-	-0.332681	1.465375	2.133592	0.526455
19	Anglesey and Snowdon	5.375260	0.838030	-	-0.332681	5.377791	5.671102	0.044433
20	Pembrokeshire	6.929128	-4.334186	-	-0.332681	4.862773	3.345808	-2.283065
21	South Wales & Gloucester	2.883550	-5.604156	-	-0.332681	0.309207	-1.652248	-2.854551
22	Cotswold	3.306248	3.451492	-8.690676	-0.332681	0.877893	-3.128490	-7.470186
23	Central London	-5.701073	3.451492	-7.118869	-0.332681	-7.500705	-10.564004	-5.898379
24	Essex and Kent	-3.694329	3.451492	-	-0.332681	-2.646413		1.220490
25	Oxfordshire, Surrey and Sussex	-0.789540	-1.862497	-	-0.332681	-1.867220	-2.519094	-1.170805
26	Somerset and Wessex	-1.096272	-3.748355	-	-0.332681	-2.928295	-4.240219	-2.019441
27	West Devon and Cornwall	0.350534	-7.963225	-	-0.332681	-3.167437	-5.954566	-3.916132

The main elements of the wider tariffs for intermittent generators are illustrated in the figure below.



Where:

- **ALF**= Annual Load Factor
- The **Year Round Shared** and **Year Round Not Shared**. These elements represent the proportion of transmission network costs shared with other zones, and those specific to each particular zone respectively.
- **Adjustment element** is a flat rate for all generation zones which adds a non-locational charge (which may be positive or negative) to the Wider TNUoS tariff, to ensure that the correct amount of aggregate revenue is collected from generators as a whole.

We think that the **Year Round Shared** and **Year Round Not Shared** elements of the wider tariff require a review in order to have a more cost reflective tariff in alignment with net-zero. These are the elements specific to each particular zone, hence these are the factors of the methodology that are driving higher costs in northern areas.

[20] National Grid ESO (Aug 2021). Forecast TNUoS Tariffs for 2022/23. Available: https://www.nationalgrideso.com/document/207346/download

2.1.1 Use of multipliers in the charging methodology

Ofgem is proposing to consider the use of multipliers in the locational charging methodology. Although today there are live CUSC modification proposals (CMP315 and CMP375) in respect to the expansion constant, the use of multipliers could potentially offset the current disparity of charges and help with predictability, stability, and cost-reflectivity of the charging regime.

2.2 Flexibility

In the consultation document, Ofgem suggests that further work in respect of charging arrangements for storage of all sizes may be warranted in the context of its potential to provide solutions to network issues rather than to act solely as a wholesale market participant. We agree that network charging is a key factor to consider in the policy regime for the development of storage, particularly for Large Scale Long Duration Storage (LLES). It will be important that the transmission charges appropriately reflect the value that these flexibility resources provide to the electricity system, both as demand and generation.

A critical function of LLES is to provide balancing and stability services to market and the network. LLES are not net MWh generators, but they are defined as generators and therefore the balancing and stability benefits (and cost savings from reduced network investment) are not reflected in the way their connection application to the grid is assessed. LLES is considered as just another generator and are connected on first come first served basis behind other generators. LLES can make a major contribution in facilitating a cost-effective transition to net-zero, by both enabling the rapid growth in variable wind and solar renewables and accelerating the displacement of fossil fuel generation[21].

We consider that the flexibility and locational benefits of LLES should specifically be taken into account in the design of transmission charges, recognising and thereby incentivising the value that these assets provide.

3. Vehicles for change

We have assessed a few options to deliver this reform and we believe that the best vehicle for change will be a 'Task Force' approach.

An open governance process is a very informal process that would not be appropriate for the scale of this reform. A Significant Code Review (SCR) is not flexible in its delivery, and it could take a long period of time out of the timescales required for this reform. On the other hand, a 'Task Force' approach aims to identify options for a broad charging topic and support Ofgem in assessing these options. We understand that each Task Force is made up of volunteers who will actively contribute by: identifying options, producing impact assessments and engaging with wider industry participants. Therefore, we see this vehicle for change as a plausible option to deliver this reform.

We would note that we believe that this reform needs strong leadership from a suitable body. A body with efficient expertise of network charging and commercial awareness to meet government ambitions. In this context, we suggest that this reform be led by Ofgem and BEIS, mirroring the way that the OTNR is presently being carried out.

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[21] Imperial College London. Whole-System Value of Long-Duration Energy Storage in a Net-Zero Emission Energy System for Great Britain. Available: https://www.imperial.ac.uk/energy-futures-lab/reports/Whole-System-Value-of-Long-Duration-Energy-Storage-in-a-Net-Zero-Emission-Energy-System-for-Great-Britain/

4. The timescales to which industry considers any reform programme should work.

A suitable timeline for reform would be between 2 and 3 years in line with the OTNR.

There is an immediate need to address the fundamental problem of TNUoS charging methodology, which is no longer fit for purpose and needs urgent reform to help achieve the required growth of renewable generation to meet challenging targets to decarbonise generation.

This urgent requirement suggests that a different approach to the usual CUSC modification approach is required and a Task Force with suitable expertise, independence and strong leadership needs to be implemented in a shorter timescale than normal.

Any vehicle to take forward this review should not prohibit the delivery of quick wins; if any party on this journey identifies a separable area of change which can reduce cost to consumers through, for example, better aligning with low-cost net-zero delivery, then it must be part of the solution to implement such a change with rapidity. Unnecessarily holding on to flaws in the status quo methodology will add undue cost to consumers.