To interested parties

Making a positive difference
for energy consumers

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Date: 11 September 2023

Open letter on strategic transmission charging reform

The energy system is changing as capacity connecting to the electricity system increases significantly and how we use the network evolves. The government is also considering proposals for electricity market reform and there are upcoming changes to strategic network planning.

Set in the context of fundamental system change and policy reform, we have been considering how network costs should be recovered through network charges and how network charging signals contribute to both investment decisions and how market participants and consumers use the energy system. We are considering whether reform is required and how changes to the design of transmission charging could provide more effective signals.

With our thinking sufficiently developed, and a further government consultation on electricity market reform expected later in the year[1], we are using this letter to set out our initial thinking on the future role and design of electricity transmission network charging and why reform may be required.[2]

We welcome stakeholder engagement on our initial thinking, including the key interactions with wider (non-charging) reform programmes. To facilitate this, we have set out some questions where we would particularly welcome early stakeholder input. We welcome views on the issues set out in this letter to WMReform@ofgem.gov.uk by 15 November 2023.

[1] Review of electricity market arrangements - GOV.UK (www.gov.uk)
[2] In this letter, we use the term "transmission network charges" to mean network charges associated with the transmission network, and we use TNUoS (Transmission Network Use of System) for specific references to Use of System charges.

Introduction

Electricity transmission network charges recover the costs incurred by the network companies in providing, maintaining, and developing the electricity transmission system. They will recover the costs of the significant onshore and offshore network expansion needed to deliver net zero. Transmission network charges play an important role in delivering an efficient net zero system, by sending investment and siting signals to electricity network users that support the efficient use and design of the electricity network. Network users must also ultimately pay for costs that may not send actionable signals, and fairness of cost recovery is also a key consideration.

For price signals to be useful, transmission network charges should work effectively as part of a coherent set of wider incentives and signals. Work is underway to address issues with the current charging framework in the near-term.[3] However, broader system changes, including increasing coordination of infrastructure build and potential reform to the role of price signals sent through government investment support schemes and wholesale markets, require consideration of the longer-term.[4]

1. Background for reform

The transformation to a net zero power system

Our future energy system will look very different to the one our current charging framework was designed to serve. Renewable generation will be the backbone of a larger future power system, with substantial investment in generation capacity and flexible assets at all voltage levels needed to deliver a fully decarbonised power system. Many large new generation assets, particularly offshore wind farms, will be located in parts of the network with relatively low levels of electricity demand. A significant expansion of the transmission network is planned for the next two decades, to accommodate this geographically dispersed generation.[5] Even with significant network expansion, the major changes to how and where we use and produce electricity mean our networks will continue to be constrained under certain conditions and in particular locations.

The shift to a renewable-dominated energy supply will be accompanied by a significant increase in the number of storage assets connected to the system. These assets will be technologically and geographically diverse. They will provide a range of system services, such as responding to fluctuations in renewable energy supply and energy demand, over a

[3] Taken forward through ongoing work on code modifications and the TNUoS Task Force: Resources - Charging Futures
[4] This letter follows on from our previous charging prioritisation letter: Open letter regarding prioritisation of electricity network charging and connections activity | Ofgem
[5] The Pathway to 2030 Holistic Network Design | ESO (nationalgrideso.com)

range of time horizons, from very rapid response to longer, inter-seasonal storage. Some storage assets will also play a role in the management of electricity network constraints.

An increasing proportion of generation and storage capacity is connecting to the distribution network, with this trend expected to continue.[6] The shift towards a larger number of smaller, distribution-connected assets is having a significant impact on electricity network energy flows. In the past, flows from the transmission network to the distribution network dominated. Now, energy increasingly flows from parts of the distribution network to the transmission network. This is evidenced by the increasing need for transmission network reinforcement to enable the connection of distributed generation, with more than 70% of grid supply points now affected by transmission-level constraints.[7]

The evolving role of transmission charges

Coordinating investments across energy and network assets, to maintain system reliability and minimise consumer costs during this system transformation will be challenging. To address these challenges, it is important that new energy assets (generation, demand and storage) connect in locations that provide overall benefits to consumers (where this is considered to be in their interests when taken as a whole). It is also vital that existing and new assets operate in ways that make best use of available network capacity. Together, this can support the most efficient use of the transmission networks, allowing necessary network expansion to be proportionate and lower cost.[8]

Transmission charging arrangements are one of the policies and signals that drive investment decisions by electricity network users. Locational signals that best reflect the physical realities of the system and support optimal network development may be achieved through a combination of potential reforms to wholesale markets, transmission network access rights, investment incentive schemes (such as Contracts for Difference reform[9]) and electricity network charges for transmission and distribution.[10] Ultimately, future transmission charges will need to work coherently with these wider market signals, and system planning arrangements.

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[6] National Grid ESO's Future Energy Scenarios (FES) 2023 provides long-term projections for the growth in distributed generation https://www.nationalgrideso.com/document/283101/download (page 142). For details of the recent and expected future increase distributed storage assets see: ENA SCG Battery Storage Solutions - Ofgem letter of support | Ofgem, Subsidiary documents: ENA SCG Electricity Storage Solutions Connections - ENA Letter.

[7] ENA SCG Battery Storage Solutions - Ofgem letter of support | Ofgem, Subsidiary documents: ENA SCG Electricity Storage Solutions Connections - ENA Letter

[8] TNUoS reform could have significant impact on a wide range of consumers. The distributional impacts of TNUoS reform will be assessed as part of any future impact assessment.

[9] Introducing non-price factors into the Contracts for Difference scheme: call for evidence - GOV.UK (www.gov.uk)

[10] Note that the potential for changes to access rights was flagged in the 2022 REMA consultation: Review of electricity market arrangements - GOV.UK (www.gov.uk)

Work is therefore underway to:

- improve the current Transmission Network Use of System (TNUoS) charging methodology to ensure the TNUoS regime remains fit-for-purpose for the system we have today and will have over the next decade, and

- consider more fundamental reform to the purpose and role of transmission charges, which is the focus of this letter.

We note that work is also underway to examine wider reforms, primarily through the UK Government's Review of Electricity Market Arrangements (REMA). We discuss this further below.

Improvements to the current TNUoS methodology

The current methodology for TNUoS charging in Great Britain (GB) is designed to send cost-reflective, relative price signals to network users. This aims to incentivise efficient network use and development by ensuring that network users face charges that reflect the costs or benefits arising from their choice of location.

Transmission connected generators that are located in areas closer to demand have a lower tariff and may even receive negative charges under the current TNUoS framework.[11] By contrast, where generation capacity is located in an area (such as the north of Scotland) far from demand, then the locational wider TNUoS tariff is higher.[12] Further information on our legal and regulatory framework is set out in Annex 1.

We recognise there are challenges with the existing methodology, in particular, that charges can be unpredictable, and this may hinder some investment decisions. We recognise reforms to the existing methodology are needed relatively urgently and, to this end, have established the TNUoS Task Force.[13]

The TNUoS Task Force is focussing on potential changes to improve the stability and predictability of the existing TNUoS framework, such as inputs to the Transport model and assumptions about different users' impacts on the network, as well as considering core aspects of the basis on which signals are sent to different network users. It is focussed on changes to the charging methodology to deliver improved signals within the wider context

[11] Note that a significant proportion of generators in GB, that are connected to the distribution networks, receive charging 'credits', or payments, for using the electricity network.
[12] Wider tariffs are the part of TNUoS that relate to the geographic location that the generator is connected. There are 27 generation zones in Great Britain with their own specific wider tariffs.
[13] [What is the Transmission Network Use of Systems Charges Task Force? - Charging Futures]

of the current wholesale market design and approach to system planning. The Task Force is targeting implementation of change between 2025 and 2026 (at the latest). We consider that these changes are necessary now and cannot wait for wider reforms as unpredictability in TNUoS charges has been identified by stakeholders as a barrier to low carbon investments.[14]

We recognise that, separately to the Task Force, there are Connection and Use of System Code (CUSC) Modification Proposals relating to the TNUoS charging methodology which are currently proceeding through the standard open governance process. Some of these propose relatively fundamental changes and we consider it important to have regard not only to the current TNUoS framework when assessing these proposals, but the potential shape and purpose of TNUoS over the longer-term. We will continue to make relevant decisions in accordance with the established framework, consistent with our Principal Objective and other statutory duties.

Wider energy policy reform context

Looking further into the future, the policy context in which we make decisions affecting the energy system is changing. While longer-term policy reforms are still developing, with some outcomes subject to significant uncertainty, they are likely to materially change how investment decisions are made in the sector and how market participants and consumers use the system. These changes require us to explore whether more fundamental reform to transmission charging is required.

Key policy changes driving the need to consider broader transmission charging reform include:

(i) Forthcoming government decisions on the Review of Electricity Market Arrangements (REMA)[15]

REMA aims to identify and implement reforms to GB electricity markets to unlock the necessary investment in and drive efficient operation of a secure, low carbon electricity system, ensuring that our electricity markets are fit for purpose over the period to 2035 and beyond.

REMA is seeking to improve locational signals, for both investment and operational decisions, to efficiently deliver a decarbonised power system and balance an increasingly

[14] Through our 2022 Call For Evidence on Transmission Network Use of System Charges [Microsoft Word - TNUoS Next Steps 250222 (ofgem.gov.uk)]
[15] [Review of electricity market arrangements - GOV.UK (www.gov.uk)]

complex system, securely and at low cost. Improvements in the signals sent through network charges (as part of a wider charging review) may be a key element of this. REMA has the potential to directly impact the future role for transmission charges, with different outcomes influencing the benefits of alternative options for TNUoS design. Similarly, different long-term TNUoS design options will impact the expected benefits of certain options being considered through REMA. Section 4 below sets out some of the ways that signals for investment through transmission network charges could be improved.

Ofgem is supporting the government in its consideration of market reform options by providing expert advice on options under consideration and the interdependencies between them. As part of this we are also considering access reform options, which, like TNUoS reforms, fall under Ofgem's remit. Whilst the REMA process will influence our programme of work, there is also the potential for TNUoS reforms to influence decisions made by the government under the REMA programme. To this end, any work that Ofgem progresses on strategic charging reform and access reform will be aligned temporally with the government's work on REMA, to facilitate effective decision making.

(ii) Increasing coordination and planning of infrastructure and accelerating its delivery

The government and Ofgem are reforming the approach to how new infrastructure is planned and built to enable the transition to net zero. These reforms could affect the overall benefits of different approaches to TNUoS in the future. Key policy reforms include:

- A more strategically planned transmission network and system. The introduction of the Future System Operator (FSO) will enable this, which is expected to take an increasingly significant role in strategic network planning and facilitating competition. This includes responsibility for the new Centralised Strategic Network Plan (CSNP), which sets out load-related transmission network investment plans to achieve net zero, and also includes advice to the government to inform the planning of the wider energy system.[16]
- The ambition to halve the development time required for new transmission network. The recent Electricity Network Commissioner (ENC) report contained a list of recommendations, which included a Strategic Spatial Energy Plan, building upon Ofgem's work to establish strategic national and regional planning as detailed above. There are also recommendations to unlock and

[16] The first full CSNP is expected in 2026, subject to Ofgem decision at the end of this year. During this transition there will be a transitional CSNP (tCSNP) to continue informing network planning and investment decisions whilst we develop the enduring CSNP process. The first transitional CSNP (tCSNP1) was published in July 2022. This included the Holistic Network Design (HND) and the NOA 2021/22 Refresh. These publications together provided onshore and offshore network designs and investment recommendations required to deliver the UK government's ambition for 50GW of offshore wind by 2030. The second tCSNP is expected to be published at the end of this year. We also have the Accelerated Strategic Transmission Investment (ASTI) framework to support the accelerated delivery of strategic electricity transmission network upgrades needed to meet the government's 2030 renewable electricity generation ambitions.

accelerate infrastructure investment; implement reforms to the consenting process; and end delays in grid connections to homes, businesses and public services.[17]

- The future of network price controls and Ofgem's consultation on the required frameworks for this future network regulation.[18]

(iii) Distribution Use of System (DUoS) charging Significant Code Review (SCR)

DUoS charges recover the costs of operating and maintaining the distribution system. We have restarted the DUoS SCR that had been paused in 2022 due to resource constraints. The SCR will consider whether changes to distribution charging arrangements would facilitate more efficient use and development of the distribution network, for the benefit of consumers.

Some large generation, storage and demand assets are able to connect at different voltage levels. We will seek to ensure that long-term arrangements for TNUoS and DUoS work well together, seeking harmonisation where possible and appropriate, and that differences in the charging frameworks don't create distortions to competition or drive inefficient investment decisions related to connection voltage.

Currently, there are significant differences in charging and access arrangements between transmission and distribution, which we consider should be assessed together. As an example these differences include:

- Transmission-connected generators pay locational TNUoS charges and have firm network access rights.
- Charges and access rights for distribution-connected generators depend on their size and whether or not they have access to certain markets.

Some generators may choose to connect at distribution level to avoid locational TNUoS charges. The value of this distortion, known as embedded benefits, varies for generation sites according to their location, voltage, connection type and technology. Options to mitigate this distortion were considered in the initial phase of the Access SCR.[19] However, due to the complex interactions between this issue and transmission network access rights, no changes were included in the decision for the first phase of the SCR (the Access SCR) in 2022.

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[17] Accelerating electricity transmission network deployment: Electricity Networks Commissioner's recommendations - GOV.UK (www.gov.uk)
[18] Consultation on frameworks for future systems and network regulation: enabling an energy system for the future (ofgem.gov.uk)
[19] Access and Forward-looking Charges Significant Code Review - Consultation on Minded to Positions | Ofgem

(iv) Permitted Range for generator transmission charges

There are a number of requirements for transmission charging that have been retained from EU legislation. In particular, annual average transmission charges paid by generators (subject to certain exceptions) must be within the range of €0-2.50/MWh ('the Permitted Range').[20] Under the current framework, a generation adjustment is used to ensure average generation tariffs are within this range. This adjustment is funded through a corresponding increase to the demand residual charge, which is paid by consumers.

Under the current framework, the locational wider TNUoS charge to generators generally increases alongside transmission network costs. The Permitted Range, which the wider charge is subject to, is legislated at a fixed level (i.e. not index-linked). As a result, we expect the size of the adjustment to increase significantly if generators continue to be charged under the existing methodology.

This has a material impact on the overall TNUoS signal to generators and its effectiveness. As outlined above, TNUoS charges to generators are designed to send them locational signals to drive system efficiencies. If this design risks annual average TNUoS charges faced by generators exceeding the Permitted Range, the resulting adjustment is paid to all generators, through a mechanism that is not designed to send a cost-reflective signal. This dynamic affects the overall effectiveness and efficiency of the TNUoS charging approach.

If current arrangements are retained, and this is a decision for the government, the Permitted Range may be a material consideration in strategic transmission charging reform. In this case, we would need to consider the effectiveness of TNUoS charge design in the full context of (i) the signal sent by the locational generator charge; (ii) the altering of this signal by the adjustment; and (iii) the expected cost of the adjustment to consumers.

[20] With some exceptions as described in The Electricity Network Codes and Guidelines (Markets and Trading) (Amendment) (EU Exit) Regulations 2019 (legislation.gov.uk) and Commission Regulation (EU) No 838/2010 of 23 September 2010 on laying down guidelines relating to the inter-transmission system operator compensation mechanism and a common regulatory approach to transmission charging (Text with EEA relevance) (legislation.gov.uk)

(v) The government's proposed introduction of a Strategy and Policy Statement for energy policy (SPS)[21]

Approving the design of network charges is a core regulatory function for the Authority[22], and TNUoS charges may be integral to future system and network planning. In our work here, we balance several competing principles. A number of these are reflected in the draft SPS for energy policy in GB: cost-reflectivity, enabling net zero (which, if the Energy Bill comes into force, will include our updated principal objective including consumers' interests in the Secretary of State meeting relevant obligations under the Climate Change Act 2008), fairness, predictability, and transparency.[23] If the SPS is formally introduced by the government, we will be required to have regard to the strategic priorities when carrying out our functions.[24] The REMA assessment criteria overlap, in many respects, with both these SPS principles and our statutory duties. Annex 2 provides an overview of both the REMA assessment criteria and the draft SPS charging principles and how they align.

Questions for stakeholder feedback:

- *Do you agree with the need to consider the future role and design of transmission charges in light of system changes and developing policy reforms? Which of these policy areas do you deem as more or less material?*
- *Are there other reform programmes not considered here that are likely to have a material bearing on the future role and design of transmission charging?*

2. Objectives of transmission charging

This section discusses our long-term objectives for transmission charging. We expect any significant changes to the structure and role of network charges to remain consistent with the principles that have historically underpinned our decisions on network charging (insofar as there continues to be alignment between these principles and our statutory duties). These principles are listed in Annex 2 and are likely to be set out in the SPS. The objectives for future strategic transmission reform are therefore likely to combine adherence to these principles, with a modernisation of the charges, in the context of the fundamental system and policy changes outlined above.[25]

[21] Strategy and Policy Statement for energy policy in Great Britain - GOV.UK (www.gov.uk)
[22] Ofgem (Office of Gas and Electricity Markets) is Great Britain's independent energy regulator. Ofgem is governed by the Gas and Electricity Markets Authority (GEMA), also referred to as the Authority.
[23] Strategy and Policy Statement for Energy Policy in Great Britain: consultation (publishing.service.gov.uk)
[24] Under the Energy Bill, if enacted: Energy Bill [HL] (parliament.uk)
[25] A transmission charging reform effort would likely be characterised by the need to make material trade-offs between the charging principles. For example, cost reflectivity and the enablement of net zero may come into conflict when considering changes to generators' transmission charges, or how to charge demand users that are investing in industrial electrification.

The main function of TNUoS is as a mechanism to recover the costs of providing, maintaining and developing the electricity system, of which fairness is a key consideration. In addition, it is possible to design network charges to send price signals to network users that users are able to act upon in ways that support the efficient use and design of the electricity network, over both operational and investment time horizons. For the reasons explored below, our view is that transmission charges are most effective when used to provide investment signals and less effective as operational signals.

This section discusses the case for network charges sending operational and investment signals, then outlines the main elements of transmission charge design that make up a useful investment signal. The following section describes the key decisions and elements that are used to design an investment signal for transmission charges. Section 4 then outlines several key open questions regarding the use of network charges as an investment signal, considering signals to different network users, asset sizes and connection voltages.

Operational signals

Effective operational signals aim to facilitate more efficient use of existing network assets and the effective integration and use of future assets, to reduce overall system costs, including the costs of balancing the system in real-time. In practice, this means using existing network capacity as efficiently as possible by influencing how generation, storage and demand assets respond to system conditions which vary by time and location.

In theory, network charges could be designed to provide operational signals to influence how the network is used in real time.[26] To be effective, these charges would have to be (i) cost-reflective, to enable participants to make efficient decisions about how to respond to them in real time, and (ii) able to operate coherently with other markets and signals, including wholesale and balancing arrangements, distribution network charges and flexibility markets.[27]

There are significant challenges to achieving these objectives. An operational charge would need to signal the costs of scarce network capacity in particular locations, in real time. To be accurate, such charges would need to be derived from a robust whole system model that is synchronised with, or able to accurately simulate, wholesale, balancing and flexibility markets. This would represent a step change in the complexity of charging arrangements which would require a major transformation of the technical systems that underpin system

[26]Currently, TNUoS does not send operational signals to generators. However, there are ex ante operational signals for non-half- hourly (NHH) demand and ex-post operational signals for half-hourly (HH) demand.
[27] Procurement of flexible resources that sits outside BM and WM. Examples include ESO’s Demand Flexibility Services, as well as the flexibility provision procured by DNOs.

operation and wholesale and balancing markets in GB today. As the system transforms to facilitate the achievement of net zero and the number of market participants proliferates, the task of real-time forward simulation of the system will become more complex.

Without a major technical transformation, operational charges would be estimated using cost models that are not integrated with other markets. This would likely lead to charges that come into conflict with signals from other markets in real time. This could lead to unexpected or inefficient behaviour from market participants and could exacerbate the operability challenges that will be faced by the FSO.[28] With increasing levels of variable renewable generation, and flexibility responding close to real-time, it will be increasingly challenging to ensure an ex-ante network charging signal delivers the behaviour that the system requires.

These challenges, in combination, mean we do not believe that sending operational TNUoS signals could actually deliver system efficiencies and cost benefits for consumers. Our view is that there are more effective ways to send operational signals that are under consideration through the REMA work programme and that, in the long-term, **signals sent through TNUoS should solely seek to influence the investment decisions of system users and not real-time operation**. This is consistent with previously stated views, notably in the open letter we published in March 2020 as part of the Access SCR where we set out our view that a short-run marginal cost approach can only be efficiently created through a market-based approach.[29]

Investment signals

Investment signals indicate where to invest and what to invest in. Our view is that transmission charges, through both connection charges and use of system charges, can be designed to effectively influence investments by signalling the long-run costs associated with certain assets, in particular locations in the network. This signal can influence both new investments, as well as retirement and repowering decisions for existing assets.

Cost-reflective charging ensures that network users whose investment decisions affect the capital costs of building and maintaining transmission network infrastructure face a locational signal that reflects this. This is intended to support the development of an economically efficient system at lowest cost to the consumer.

[28] Chapter 9. Operability outlines the operability challenges faced by System Operator [Review of Electricity Market Arrangements (publishing.service.gov.uk)]

[29] The advantages and disadvantages of using locationally granular and dynamic network use-of-system charges to send operational signals have been explored elsewhere. [Electricity Network Access and Forward-Looking Charging Review: Open Letter on our shortlisted policy options | Ofgem]

Other characteristics of an effective investment signal include:

- Sufficient predictability that they can efficiently be incorporated into investment decisions.
- Signals are sent to groups of assets that have a reasonable ability to respond to them.

Investment signals from network charges should also interact effectively with other investment signals and wider influences on market participants, such as government policy and system planning approaches. Energy policy changes to deliver a net zero system may have fundamental implications for how the investment signal from transmission network charges should be designed. This is discussed below in Section 5.

Questions for stakeholder feedback:

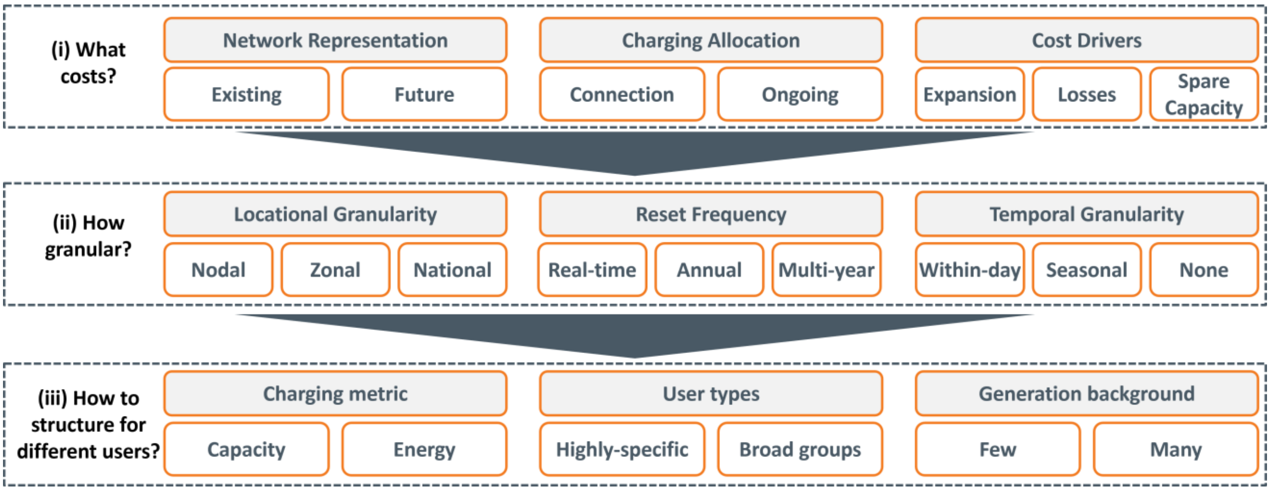
- *Do you see reasons to alter our current view not to design transmission charges to send dynamic operational signals for generation and demand in the longer-term?*
- *In addition to those described above, what would be the other key characteristics of a future design, for the transmission charging framework, to enable its effective incorporation into investment decisions so as to achieve cost-effective net zero?*

3. Framework for transmission charge design

Network charge design is a complex process. The charges that are recovered from a particular network user are the result of many distinct, interlinked design elements. This section provides a simplified framework for understanding how reform options could be developed, through a series of sequential design decisions. It also provides a preview of the types of charge design decisions that may emerge from a reform process.

Section 4 discusses the key questions that would drive any reform process, with direct reference to the elements below. This framework therefore provides a point of reference to understand how the specific questions in Section 4 could influence charge design. Note that it is possible that, depending on the other locational signals sent, the best solution is that no locational signals are sent through transmission network charges. The framework is summarised in figure 1 with the series of design choices described below.

Figure 1: Design framework for transmission network charges



(i) What costs to signal?

There are many potential approaches to estimate the costs that should be associated with certain uses of the transmission network, to develop cost-reflective charges. We consider three key choices below.

Network representation:

- With the move to a more centralised and strategic approach to network planning, as set out in Section 1, the costs reflected in TNUoS could reflect the network as it is expected to be in the future, rather than today's methodology of the current network. Use of system network charges that reflect the existing network configuration at the time of charging require network users to invest based on their knowledge and understanding of future network planning and development, and how this will be reflected in the charging framework.

- An alternative approach is to have forward-looking network charges reflect the planned network to improve predictability. In light of the changing approach to power system planning, such as the Holistic Network Design (HND) program,[30] CSNP, and the recent recommendations from the ENC report, **our initial view is that use of system charges should aim to reflect the forecasted future planned network**. This would reduce future uncertainty and could align the investment signal of the tariff with the network planning recommendations set out in the CSNP. By doing this, there would need to be a high level of confidence that the network build delivers to the scale and timings as forecasted, otherwise there runs a risk of inaccurate signals being sent to parties.

[30] The Pathway to 2030 Holistic Network Design | ESO (nationalgrideso.com)

Allocation of Transmission Owner investment costs to different charge types:

- A greater amount of transmission network costs could be recovered through connection charges (ie a deeper connection charge), compared to the ongoing use of systems tariffs (both forward-looking and residual).[31] It is possible to use connection charges to influence investment decisions. Recovering more of the total costs incurred as a result of connecting new demand, storage or generation to the system through an upfront fixed connection charge can send a strong investment signal, providing certainty for investors.

- As there is a direct pass through of the network upgrade cost to the connecting user, this more directly reflects the costs when compared to Use of System costs, which have to approximate the costs in the wider system caused by each market participant.

- There is a question of whether requiring significant amount of upfront costs through the connections charge could negatively impact the investment in generation and demand required for the net-zero transition. As identified in our Access SCR decision, there would be a risk that deeper connection charges could result in freeriding and ineffective signals, which would need to be explored further.

- We will publish a joint Connections Action Plan with the government, seeking to improve the current connections process. As part of the longer-term work, we will consider whether changes to access and connection charges are required to better enable faster connections; this will be considered closely with future charging reform work, which seeks to improve the current connections process.

Cost drivers reflected:

The design of network charges could be altered to reflect the different cost drivers and how they impact different users of the system. The options that we are considering are that either they continue to be based on the costs of building and maintaining the network in the long term or alternatively, the costs could be allocated considering the costs of the impacts on the network (current or future) in terms of constraints or losses. The design could consider a combination of these cost drivers.

[31] Under current connection charging arrangements, connection charges enable transmission operators to recover, with a reasonable rate of return, the costs of installing and maintaining Connection Assets that connect individual users to the GB Transmission Network. Connection Assets are non-sharable assets installed for and only capable of use by an individual user, representing a shallow charging regime. All sharable assets are classified as infrastructure assets, and the costs associated with them are recovered through TNUoS charges.

- **Long run network cost (expansion-based) network charges** reflect the capital costs of building and maintaining the network in the long term.[32] As with other cost drivers, the objective is to internalise reinforcement costs in network user decision making, leading to an expected reduction in network development costs. However, expansion-based network charges mean that new-build network assets to enable the reaching of net zero targets could lead to very high TNUoS charges as the location of much of the planned generation is remote to demand centres. This could create disincentives for generators to connect to those new build networks, leading to underutilisation and potentially exposing consumers to a greater risk of stranded investment.

- **Locational network losses-based charges** reflect the cost of transmission losses, incentivising new generators to site close to demand and so reduce the cost of network losses. Losses can be estimated for each node of the network and may be positive or negative (ie a payment to the generator) depending on the exact location and power flows.

- **Spare capacity-based network charges** reflect the costs of network constraints in different areas. The objective is to incentivise network users, both generation and demand, to make siting decisions that allow available network capacity to be used and reduce the need for additional network build and reinforcement. Consideration of how this could work with wholesale market reforms is outlined below in Section 5.

(ii) What level of granularity to use in cost allocation?

Once relevant costs have been determined, the level of granularity of allocation must be decided, across network locations and different time scales. We consider three key choices below.

Locational granularity:

- The locational design of the charges could be broken down to different scales ranging from highly granular or nodal charges, to zonal or even national, with no variation between locations. The boundaries of zones in zonal pricing may be decided based on the location of transmission network constraints and may be redefined over time, to reflect expansion of the network and changes in the nature of network use.

[32] These charges could potentially be set and fixed when a generator connects, reflecting the long-run incremental cost of reinforcement at the time of connection.

- The existing zonal arrangement uses 27 zones to determine the charges to network users. This sends a locational investment signal, incentivising generator to locate in locations with lower charges, although this is only one component of the total costs that drive a siting decision.

- If the locational granularity of these charges were increased, eg a nodal approach with differing charges for each transmission Grid Supply Point (GSP), then this approach would account for variations of costs within the 27 existing zones. This would result in differentiation in costs between locations, sending a more targeted and stronger locational signal for investment. However, this could also result in some areas experiencing significantly higher costs.

Frequency of reset of charges:

- Network charges require periodic reset/review to reflect the most up-to-date cost of using the network. This could range from dynamic charges that change in real time, all the way to longer-term, potentially multi-year charging periods. Alternatively, charges could be set annually but via a form of longer term TNUoS contract so that charges faced by some categories of network users are stable for a period of time after connection. There are trade-offs that need considering between the predictability that would be seen in a lower frequency of reset and the cost-reflectivity of the charges with a higher frequency of reset. As our initial view is to rule out TNUoS sending an operational signals via dynamic charging, we therefore are proposing **ruling out a real time frequency reset of charges**.

Temporal granularity:

- This addresses the question as to how charges should differ for users over different periods throughout the day, year, etc, based on the changing cost of using the network at different times. This is distinct from, but related to, frequency of reset. Charges may vary on a seasonal basis or apply differently to peak times and off-peak times for network use. The intention of temporally granular charges is to influence general patterns of usage to reduce costs in the long term. Setting temporally granular charges ex ante is only suitable where there are predictable temporal cost drivers. In the past this has often been evening peak demand, however, in the future it may be more complex, as new technology and customer behaviour bring changes in how the networks are used.

(iii) How to structure the charge for different network users?

Once costs associated with a specific timeframe and location have been determined, those costs must still be attributed to network users, according to specific parameters, actions or characteristics. Three key design parameters are described below with key questions to consider:

Charging metric:

- What is the basis for calculating the charge for a specific user type? Choices between capacity (£/kW) and energy consumption, or volumetric (£/kWh) based charges should be consistent with the cost allocation choices and the different network impacts that would be reflected.

Treatment of different network users:

- How to charge different demand and generation user types, according to the characteristics that influence their impact on the network (eg connection voltage, size, load factors, generation and demand profiles).

Generation background:

- Where charges are determined ex ante, assumptions must be made about the network conditions (ie supply and demand characteristics) that best approximate the cost allocation methodology that has been designed. The conditions of these 'backgrounds' are then an important basis for allocating costs to specific network user types.

Questions for stakeholder feedback:

- *Are there other key drivers that should be factored into the transmission charging framework? Which of these drivers do you see as most important?*
- *Do you have any views on which of these approaches would be more effective, considering the energy transition?*
- *Do you agree that TNUoS charges should reflect planned future network conditions rather than actual network conditions?*
- *Do you agree that the frequency of reset should be longer than 'real-time', to ensure an effective investment signal can be sent?*

- *Have you any views on how trade-offs between predictability and cost-reflectivity in considerations of how frequently network charges should be reset should be managed?*

4. Key questions for transmission charge design

This section outlines some key implications of the changing system and policy context discussed in Section 1 for network charging. Specific questions that would be addressed through a charging reform program are raised. These questions should be considered in the context of the objectives for transmission charging that were outlined in Section 2 and the charge design framework described in Section 3.

The questions mainly concern the treatment of different network user types in the context of their changing characteristics and impacts on the network. They also cover alignment of investment signals at different voltages as well as the potential use of transmission charges to signal constraints.

(i) Investment signals to generation

The historical configuration of the network was dominated by electricity flows from large generators to demand centres in towns and cities. In such a system, it made sense for the charging framework to be designed to reflect that siting generators close to demand centres can avoid the need for network upgrades.

As outlined in Section 1, use of the network is changing in fundamental ways due to the increase in distribution-connected generation and storage, and the proliferation of renewable energy generation in new areas. In addition to network flows becoming more complex, we also expect significant new network investments across a vast proportion of the network.

In this context, a highly locationally-granular charging model may be able to identify generators which, on balance, reduce the overall cost of the network on the basis of their connection location. However, the TNUoS credits that are paid to generators today, under a zonally averaged model, may not be reflective of actual benefits conferred by the generators who receive them.

Currently, such credits are calculated on the basis primarily of distance to demand, rather than, for instance, utilisation of available or ‘spare’ capacity on the network. This calls into question whether payments to some generators for using the network can be justified on either a cost-reflectivity or fairness basis. The TNUoS Task Force Terms of Reference specifically include this question, as well as broader questions relating to the distance-to-demand basis on which charges are calculated. These are being considered in the context of the current shallow connection boundary and the need for annual average transmission charges paid by generators to fall within the Permitted Range.

The future of generator transmission charges will also be influenced by the Permitted Range. If current legislation is retained, the proportion of TNUoS costs that are recovered directly from demand is expected to increase.[33] To protect consumers interests in this context, consideration will be given to the most efficient design of charges, with specific regard to the impact of the Permitted Range. Although it is an important contextual consideration for our regulatory work, the decision whether to retain, amend or repeal the retained European Commission Regulation 838/2010 is a matter for the government.

Question for stakeholder feedback:

- *Is there an enduring justification for paying credits to generators, specific to their siting location, through their transmission charges?*

(ii) Investment signals to storage

As described in Section 1, we expect a significant increase in investments across a range of energy storage assets as part of the transformation to a net zero power system. Storage is currently treated as a subset of generation in network charging. However, storage assets play a number of distinct roles in the electricity system and could confer very different system costs and benefits, compared to generation.

Storage projects exhibit unique characteristics, behaving as both demand and generation, often with low utilisation and low operational predictability. It is for this reason, along with firm access rights, that battery storage can result in significant reinforcement works.[34]

As a result, there may be an opportunity to update charging methodologies to improve the accuracy of the investment signal sent to storage providers and encourage more beneficial siting decisions.

[33] As described in Section 1, the €0-2.50/MWh limitation on average generator charges has a material impact on transmission charge design. Where charges exceed the Permitted Range in one part of the methodology, generators must be compensated with credits, to bring overall charges back within compliance. These credits, which are funded by consumers, are paid to all generators on basis of their capacity, and do not send effective investment signals.

[34] ENA analysis shows average industrial-scale battery capacity utilisation is just 4.6%, and ~80% of their contracted capacity sits idle for ~95% of the time. We provided support on 15 August 2023 for initiatives to better facilitate battery storage connections at distribution level [ENA SCG Battery Storage Solutions - Ofgem letter of support | Ofgem]

Questions for stakeholder feedback:

- *How should the distinct characteristics of storage assets be reflected in their treatment in network charging, to encourage optimal investment outcomes across the large storage development pipeline?*
- *Within the range of storage assets, what distinctions should be taken into account in the charging approach?*

(iii) Investment signals to demand

There is significant variation across demand users of the network: from large industrial facilities where electricity network charges are a major factor in investment decision-making, to households and small businesses that are less likely to take electricity costs into account when making decisions about where to locate.

Electricity demand is set to increase significantly across most user types to accommodate the electrification of heat, industrial processes and transport as the UK moves towards net zero. To the extent that this new demand will drive network reinforcement costs, locational signals that influence siting of demand may be valuable. However, the value of this signal will depend on the ability of investors in new sources of electricity demand to respond.

Network charging signals could influence other investment decisions by demand users of all sizes, that shape the nature of network use in the future. For example, investments in electric heating, smart appliances, EV charging and solar PV by households could have different impacts on transmission and distribution costs, depending on which technologies are adopted and how they are used. Future charging arrangements will need to balance: (i) enabling households to switch to these low carbon technologies; (ii) encouraging decisions that minimise the cost impacts of these technologies on the network overall; and (iii) ensuring that all households are treated fairly in the charging framework.

In today's charging approach, costs that are not sending a signal are recovered through the residual charge, which is designed as a fair, efficient cost recovery mechanism. In the future, there may be a significant increase in the level of the residual, in the context of the significant increases in the level of transmission costs overall and the impact of the Permitted Range on options for an efficient charging signal to generators. The design of the demand residual charge may need to be revisited in this context.

Suppliers currently face network charges on behalf of their customers. Suppliers then have a role in determining whether and how charging signals are passed through to consumers, and they combine options into retail tariffs, alongside the other costs associated with supplying their customers. More granularity in network charges could prompt the development of innovative retail offerings, enabling consumers to have more control over, and more reward for, how they use energy. While this may enhance competition in the retail market, it could also give rise to a range of technical, economic and socio-political challenges. As part of our wider work to support a smarter, more flexible energy system, we may need to consider whether any further changes to retail arrangements are required to ensure that benefits are maximised and consumers remain protected.

Questions for stakeholder feedback:

- *To what extent should transmission charges send locational signals to large demand users of the network?*
- *What level of locational variation in charging is appropriate, for smaller demand users who are not generally expected to change siting decisions based on the signal?*
- *If there are significant increases in the costs recovered through the residual charge, should alternative charge designs be considered?*
- *Should transmission network charges play a role in encouraging households and small businesses to make efficient investments in low carbon technologies?*

(iv) Investment signals at different connection voltages

Network users have historically faced charges that are tailored to the voltage that they connect to the network, either transmission, extra-high voltage, high voltage or low voltage. Charges have generally assumed that electricity flows from higher to lower voltages, meaning that most larger users do not contribute to the cost of networks at lower voltages than their point of connection.

There are other significant differences in charging methodologies at different voltages, including different methodologies for apportioning costs and different charge structures. Some of these differences stem from the difference in network access rights for connecting parties at different voltages and their historically different roles in the electricity system and various markets.

As described in Section 1, both network flows and the role for and market participation of smaller assets are changing in fundamental ways as the number of distribution-connected generation and storage assets increases, and there is a proliferation of renewable energy generation in new areas.

These changes may require adjustments to historical approaches to reflecting costs and benefits in transmission charges for generation, demand and storage.

Questions for stakeholder feedback:

- *How should charges for large generators and large demand users at different voltages account for the increasing proportion of distributed generation and the changing nature of network flows?*
- *Should there be greater alignment of charging obligations and methodologies for transmission- and distribution-connected assets, to encourage efficient connection voltage choices by generation and storage assets?*

(v) Transmission access rights and constraint costs

Under today's transmission network access arrangements, electricity network users do not face an operational or investment signal directly associated with the network constraints related to their asset and its operation. Transmission-connected generators have firm access to the entire transmission network and are compensated through the balancing arrangements if they adjust their output in response to network constraints. The current transmission charging model for generators does not reflect network constraints costs, although there is, to a limited degree and not necessarily by design, some overlap between the most capacity-scarce areas and the highest-cost charging zones calculated by the model today.

There may be a case to consider the incorporation of constraint costs into TNUoS, based on our expectation that there will continue to be significant network constraint costs in the net zero power system. However, it is challenging to design an effective congestion investment signal (ie, one that reflects both internal constraints and interconnector congestion) that is both predictable and cost-reflective. The congestion cost would need to be signalled in a predictable way that can be efficiently considered in investment decisions and should also reflect the changes in costs as new transmission assets are delivered and new assets connect to the network. For this reason, consideration of whether charging arrangements are based on the network we have today, or the network as it might be in a few years' time (eg, with HND) may be relevant. This could be taken forward via the TNUOS taskforce, or via longer-term reforms.

Charges of this type may also require significant reforms to balancing and transmission access rights arrangements to ensure signals are coherent and that costs are being allocated correctly.

Question for stakeholder feedback:

- *Should transmission charges be used to signal the relative costs of network congestion (ie internal constraints and cross-border congestion) in different areas?*

5. Implications of different market and policy reforms for transmission charging

Section 3 outlined a framework for transmission charging reform and Section 4 set out key questions for the design of transmission charges to influence the locational investment decisions of network users. The market reform options being considered through REMA, and reforms to future system planning, do not change these fundamental questions. However, we do need to develop transmission charging reforms in parallel with REMA and the evolving planning framework, to ensure the wider investment framework is coherent and to minimise unintended implementation challenges.

Below we discuss wholesale market reform, other government policies for supporting net zero investments and the evolving planning framework, to highlight how different reform outcomes could influence the development and assessment of various TNUoS options.

(i) Implications of locational wholesale market reform

REMA is considering whether GB's national wholesale market should be changed in the future, for example, by splitting it into a zonal or nodal market. Both zonal and nodal wholesale pricing reflect differing locational wholesale costs (providing locational investment and operational signals), but they may not fully reflect the different network costs that market participants impose on the system when making siting decisions. In either case, transmission charges should not duplicate the locational costs reflected in wholesale prices, for example, by reflecting the costs of network constraints that are also represented in wholesale market prices. However, transmission charging could play a role in complementing locational wholesale market signals, with different design options for the zonal and nodal scenarios.

Zonal pricing: With zonal pricing, the electricity network is split into clearly defined geographical zones that typically reflect major recurring transmission network constraints, with wholesale electricity prices (£/MWh) calculated for individual zones.[35] While the cost of managing physical constraints between zones are reflected in wholesale prices (typically leading to price variation between zones), constraints within the zones are not.

TNUoS could be designed to deliver additional benefits in the form of intra-zonal locational price signals to incentivise capacity to locate more efficiently within zones, thereby

[35] In practice, major network constraints will change over time resulting in trade-offs between stability of the zones and allowing them to adjust in a more dynamic way to more closely approximate nodal pricing.

potentially reducing network costs and intra-zonal constraint management costs (which could remain significant).[36]

Nodal pricing: Nodal pricing uses a more granular spatial model of the transmission network than zonal pricing, to increase the number of defined points or 'nodes' on the network where individual wholesale prices (£/MWh) are formed. With nodal pricing, the physical constraints of the network (and transmission losses) are reflected in the market clearing process, and these costs are fed through to the wholesale price, so that the price at each node would reflect the locational value of energy at that node.

Nodal pricing would send a long run investment signal to market participants, reflecting some of the different costs associated with certain assets connecting in certain locations, particularly the costs of network congestion.[37] Certain transmission charge designs could complement nodal pricing in this context, for example by sending a predictable signal of long-run incremental network costs.

In general, combining a TNUoS investment signal with nodal pricing may lead to a duplication of signals with the wholesale market, or complexity across both sets of signals. Our initial assessment is that transmission charges that signal congestion would be duplicative to a nodal wholesale market. It is possible that, provided there were sufficient evidence as to the consumer benefits, a purely cost recovery approach to transmission charges would be used alongside a nodal market. In such a scenario, we would need to actively consider the appropriate mechanisms for the recovery of charges.

(ii) Implications of greater locational specificity in planning and government support schemes

As described above, transmission charges can support efficiency by indicating the transmission network cost implications of different connection locations. However, many factors and policy levers influence the costs and benefits to investors of different locational options for energy assets. This can lead to cases where different policy levers may send different signals about the costs and benefits of certain choices.[38] In this context, efficient outcomes should be reached when investors use all available information to bring forward projects that are the most competitive, taking all relevant costs into account.

[36] Note that some countries with zonal wholesale markets (eg Norway, Sweden) still have locational network tariffs as well as zonal markets. See p.45, 46 https://eepublicdownloads.entsoe.eu/clean-documents/mc-documents/l_entso-e_TTO-Report_2020_03.pdf
[37] Investment decisions may rely on transmission being built, which would also allow nodal wholesale prices to converge, meaning that expected wholesale prices do not entirely capture the cost of transmission.
[38] An offshore wind location that is costly from a transmission perspective may be attractive in terms of seabed licensing arrangements, for example.

Where policy interventions become highly prescriptive with respect to location, these may not support efficient outcomes in this way. This may be relevant for:

- **Future system planning approaches**: The scale of changes to system planning and the level of future policy intervention in generation and storage connections (if any) is still being worked through.[39] For example, among the recommendations from the ENC is an expanded role for the FSO to develop a Strategic Spatial Energy Plan, combining ongoing strategic network planning exercises with forecasts of generation and demand and aligning planning with National Policy Statements issued by the government and Crown Estates/Crown Estates Scotland decisions.

- **Future of government support schemes for low carbon generation**: Reforms are being considered to introduce locational limitations in the Contracts for Difference (CfD) regime.[40] The CfD is a key mechanism to drive investment decisions for renewables and therefore could drive different investment outcomes than would be expected in a national CfD allocation round.

In principle, the more prescriptive that planning processes are on siting decisions, the less useful a TNUoS locational price signal may be as the ability of new assets to respond to such signals would reduce. In an extremely granular network planning scenario where locational price signals became redundant, TNUoS for purely cost recovery could be plausible. That being said, even with greater strategic systems planning, many assets will still have choices about where they locate, with the extent of this likely to vary depending on technology type, and assets will also continue to confer a cost or benefit on the system depending on their location.

We will ensure that TNUoS design takes account of the work of the ENC, and the FSO as its role is formalised. We will also consider how reform to connections and access may affect the context for consideration of TNUoS reform, as signalled in our recent open letter.[41]

We will also work with the government to consider interactions between transmission network charging and the future design of support schemes like the CfD. For example, if support scheme design aims to incentivise lowest-cost projects at specific network locations (eg location-specific CfDs), it may be more efficient to remove or reduce locational signals within network charges. However, as the charging approach has to be non-discriminatory,

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[39] Driving Net Zero: how Ofgem is creating an energy network for the future | Ofgem
[40] Introducing non-price factors into the Contracts for Difference scheme: call for evidence - GOV.UK (www.gov.uk)
[41] Open letter on future reform to the electricity connections process | Ofgem The connections reform work could involve changes to access allocation, including through mechanisms such as auctions. The connections regime could also become more closely integrated with system planning.

and there may be risks with removing locational network charges from all assets, there may be other ways to mitigate risks for relevant projects.

Questions for stakeholder feedback:

- *What are your views on the potential implications of market reform and system planning outcomes on the benefits of different long-term transmission charging options?*
  Should locational signals from transmission charges be adapted where cost-reflective charges conflict with other policy goals and electricity market signals?

6. Next steps

This calendar year we will further assess the case for change and, subject to that progress, develop an analytical framework to support the identification and assessment of options for long-term transmission charging reform. This will be updated as we gain clarity on approaches to market reform and system planning, such as through:

- a further government consultation on REMA, expected late 2023 and
- a government response to the ENC recommendations, expected to take the form of an action plan published by the end of the year.

We are conscious that any reforms evaluated must be both effective in principle and designed so that they can be delivered in realistic timelines. We will build on the work of the TNUoS Task Force and continue to have due regard to the value of wider predictability.

We intend to engage with stakeholders at the next Charging Futures Forum, which will be held on 31 October. We welcome feedback on our current thinking, in particular on the questions included in this letter and will regularly seek engagement on this work. We will review and take account of stakeholder submissions, as well as wider engagement, and take forward more detailed analysis on the potential drivers of change and the various options under consideration. This will aid us to conclude whether long-term network charging reform is required and support a robust assessment of the potential options and associated regulatory questions, to determine whether there are solutions that could help the efficiency of the GB energy system, bringing benefits to consumers.

We welcome views on the issues set out in this letter to WMReform@ofgem.gov.uk by 15 November 2023. These responses may be used to inform the government's REMA programme so responses may be shared with relevant government teams to support consistent policy development.

ANNEX 1 – Legal and regulatory framework

In considering potential reforms, we are mindful of the changing legal and regulatory context. Relevant aspects of the current framework include:

- **Legislative requirements**: a number of requirements relating to network charging arise from domestic and Retained EU legislation.[42] For example, there are requirements with regards cost-reflectivity and non-discrimination in network charges[43], and the level of annual average transmission charges faced by generators.[44] There are also requirements and related provisions under the Trade and Cooperation Agreement between the UK and EU.[45]

- The Connection and Use of System Code (CUSC) is the **contractual framework** for connecting to and using the GB electricity transmission system.[46] It has been designed to evolve through (ordinarily industry-led) code modifications.[47] The TNUoS charging methodology is detailed in Section 14 of the CUSC. Under the open governance approach, there are currently a range of modifications to the codes in progress, which are at different stages of development.

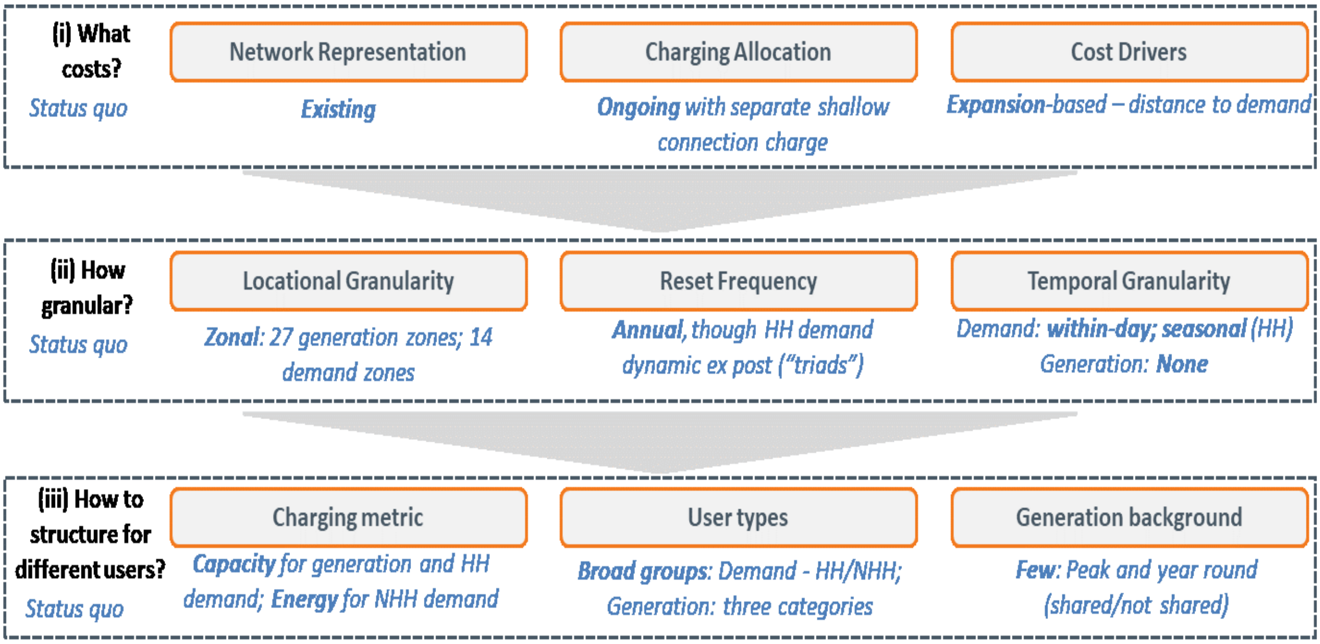
The TNUoS Task Force is considering near to medium-term improvements to charging arrangements, focusing on improving the stability, and predictability of charges, while ensuring that network users face charges reflecting their effect on the network.[48] This has clear overlaps with longer-term reform work, and we are working closely to remain aligned. The Task Force is considering the extent to which change to the current charging framework is needed, and how it should be delivered in terms of ensuring the TNUoS regime is fit-for-purpose for the system we have today and will have over the next decade.

[42] Retained EU law as a class is under review as a result of the Retained EU Law (Revocation and Reform) Bill.
[43] Regulation (EU) 2019/943 of the European Parliament and of the Council of 5 June 2019 on the internal market for electricity (recast) (Text with EEA relevance) (legislation.gov.uk)
[44] With some exceptions as described in The Electricity Network Codes and Guidelines (Markets and Trading) (Amendment) (EU Exit) Regulations 2019 (legislation.gov.uk) and Commission Regulation (EU) No 838/2010 of 23 September 2010 on laying down guidelines relating to the inter-transmission system operator compensation mechanism and a common regulatory approach to transmission charging (Text with EEA relevance) (legislation.gov.uk)
[45] Trade and Cooperation Agreement between UK and EU – CP 426 (publishing.service.gov.uk)
[46] CUSC v1.15 (nationalgrideso.com)
[47] The energy code reforms set out in the Energy Bill will, if enacted, give substantial new functions to Ofgem, including setting a strategic direction for the industry codes, and licensing and regulating code managers.
[48] What is the Transmission Network Use of Systems Charges Task Force? - Charging Futures

ANNEX 2 – SPS charging principles and REMA assessment criteria

REMA assessment criteria	Most relevant Draft SPS **charging principle(s**)
Value for money - Market design should lead to solutions being delivered at least cost to consumers and sub-groups of consumers, with ongoing incentives to keep costs low and drive innovation (through competition where appropriate). Markets should be open to all relevant participants, including demand-side and innovative technologies	• Cost-reflectivity • Fairness • Enabling net zero
Deliverability - Changes to market design should be achievable within designated timeframes and seek to minimise disruption during the transition, taking account of the highly complex and integrated nature of the power system	• Enabling net zero • Predictability
Investor confidence - Market design must drive the significant investment in low carbon technologies needed to deliver our objectives. Risks will differ by technology type, but should be borne by those best able to manage it	• Fairness • Enabling net zero • Predictability
Whole-system flexibility - Market design should incentivise market participants of all sizes (both supply and demand side) to act flexibly where it is efficient to do so. Market design should promote greater coordination across traditional energy system boundaries, including between electricity and other vectors like heat and hydrogen, to enable effective optimisation across the system as a whole.	• Cost-reflectivity • Enabling net zero • Predictability • Transparency
Adaptability - Market design should be adaptive and responsive to change. It should help ensure delivery of our objectives in a wide range of scenarios and should be robust to uncertainty, for instance regarding commodity prices and technology costs.	• Enabling net zero • Transparency

ANNEX 3 – Summary of today's TNUoS charges using the design framework



Explanatory notes

- The focus of the diagram is on forward-looking rather than residual charging. Residual charging is levied on final demand at a fixed rate (p/site/day).
- Connection charge depth refers to the relative proportions of the costs of connecting an asset that are recovered from connection charges or use of system charges. A shallower charge means a greater proportion of costs are recovered through use of system rather than connection charges.
- "HH" refers to half-hourly demand; "NHH" refers to non-half-hourly demand.[49]
- "Triads" refer to the three half-hour settlement periods of highest demand on the GB electricity transmission system between November and February (inclusive) each year, separated by at least ten clear days.
- Further information on existing transmission charging arrangements is available on the ESO website: [Charging guidance | ESO (nationalgrideso.com)](https://www.nationalgrideso.com).

[49] NHH tariffs will no longer exist when market-wide half-hourly settlement has been implemented. This is expected to be December 2026, with an alternative deadline of May 2027, to provide an additional six-month range.