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National Grid ESO response to the Call For Evidence – Transmission Network Use of System Charges

Dear Harriet,

This response is on behalf of National Grid Electricity System Operator (NGESO) and is not confidential. National Grid ESO is the Electricity System Operator for Great Britain. We balance electricity around the country second by second to ensure that the right amount of electricity is where it's needed, when it's needed – always keeping supply and demand in balance. As Great Britain transitions towards a low-carbon future, our mission is to enable the sustainable transformation of the energy system and ensure the delivery of reliable, affordable energy for all consumers. We use our unique perspective and independent position to facilitate market-based solutions which deliver value for consumers.

We believe that to ensure the TNUoS charging methodology aligns with decarbonisation goals, it is important to consider it alongside any holistic reform of the arrangements, with the charging methodology design coordinated with any developments in future market design, offshore transmission network reform and development of the Competitive Appointed Transmission Owner (CATO) regime amongst others. In our recent response to the Access and Forward-Looking Charges (AFLC) Significant Code Review (SCR): Consultation on Minded to Positions, we highlighted our support for a wider review of TNUoS. Specifically, we noted that for a review to deliver the most benefit to consumers, we believe the interactions with markets, network capacity and constraints, Balancing Use of System (BSUoS) charges, and market wide half hourly settlement needs to be considered.

Holistic reform could encompass wholesale markets including potential locational granularity, flexibility markets, low carbon support market mechanisms, and potential new markets to support Ofgem's Full Chain Flexibility programme, such as energy efficiency gains and demand side response. Therefore, while we believe the scope of a broader TNUoS review should definitely cover the elements of the locational signal for generators, there is a case to review how TNUoS paid by demand customers should be charged in light of the changing energy landscape and changing relationship between demand and generation.

We also consider that, given the interactions and dependencies involved, changes to the demand side of TNUoS, the reference node, and the option to charge distributed generation TNUoS should be descoped from the AFLC SCR and added to any future programme considering TNUoS reform. This would align with the proposal to take forward the wide-ranging review of Distribution Use of System (DUoS) charges under a separate vehicle to the AFLC SCR and with a revised timescale.

We have also heard similar stakeholder feedback to Ofgem on the shortcomings of the current methodology. We recognise the current methodology has evolved over the years, through code modifications and most recently the two significant code reviews (SCRs), which has contributed to uncertainty and complexity for stakeholders.

We are supportive of a Significant Code Review (SCR) or SCR and taskforce hybrid approach as the vehicle for change, as we believe these achieve the right balance between bringing in insights from open code modifications, coordinating changes to best manage uncertainties, and offering the opportunity to set these changes in the context of any wider market reform.

Our detailed response to specific points raised in the consultation document is appended to this letter.

We welcome the opportunity to further discuss the points raised in this response and look forward to working with both Ofgem and industry as the detail of these reforms are worked through. Should you require further information please contact Naomi De Silva in the first instance at Naomi.DeSilva@nationalgrideso.com.

Yours sincerely

Jonathan Wisdom

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National Grid Electricity System Operator

Appendix

We have organised our response around several points we considered most important to highlight.

Need for holistic review

We fully support the government's net zero targets and believe that the best way the outcomes of a review of TNUoS can support these goals and deliver the most benefits for consumers is for such a review to take place as part of holistic market reform. Transmission Use of System Charges (TNUoS) should not be considered in isolation and there should be wider consideration of the interactions with markets including wholesale markets, the Balancing Mechanism, the Capacity Market and Contracts for Difference (CfD) auctions, as well as network constraints, Balancing Use of System Charges (BSUoS), and the move to market wide half hourly settlement.

Our Future Energy Scenarios (FES), which outlines credible pathways to a net zero energy system by 2050, show dramatic changes in the energy landscape in the next 20 years and beyond. Further growth of renewable generation is anticipated both onshore and offshore, with the generation landscape no longer characterised by relatively few transmission-connected traditional spinning plant and instead larger numbers of decentralised renewable, intermittent generators alongside the growth of storage capabilities and demand side flexibility. In 2030, between 34 GW and 77 GW of new wind and solar generation could be required to meet demand, alongside up to 13 GW of new electricity storage to help balance periods of high and low renewable output and up to 6 GW of new flexible residential demand reduction. Across all scenarios between 31 GW and 47 GW of offshore wind is connected by 2030, with total electricity generation capacity increasing from 104 GW in 2020 to between 158 GW and 200 GW in 2030, an increase of at least 93%.[1]

In light of the uncertainty of these changes, our Network Options Assessment (NOA) highlights how exploration of the relationships between transmission charging and the wider landscape is critical to developing an economic and efficient transmission network and for minimising costs across TNUoS and BSUoS which are both ultimately borne by consumers.[2] The costs of actions taken to manage constraints, such as curtailment of intermittent renewable generation, are recovered via BSUoS charges. The impact of higher constraint costs in the short term is balanced against the risk of stranded assets to determine the optimal timing and nature of transmission reinforcements. The cost of these reinforcements is recovered via TNUoS charges.

Given NOA 2020/21 identifies the need to invest at least £16bn to manage heavily constrained system boundaries into the mid-2030s[3], it is critical to coordinate TNUoS charging design with the overall design of future markets for net zero. Our 2020/21 paper on modelled constraint costs highlights how thermal constraint costs, the largest element of constraint costs, are forecast to rise from circa £0.5bn today to between £1bn and a maximum of £2.5bn per year before they reduce again at the end of the 2020s when new major transmission investments come online. This is because the timescales to increase network capacity through large transmission investments are generally longer than those to connect the large quantities of renewable generation required to meet net zero.[4]

As you are aware, we have been engaging with the industry on net zero market reform.[5] The second and current phase of the project is focused on gathering evidence for the case for change from investment, flexibility, locational signals, and operability perspectives across a range of stakeholders. In addition, the second phase sets out the framework for assessing options for the key market design elements, which we expect to share later this month. This evidence will be taken forward into the next stages of the project to support identification and assessment of potential market solutions.

Early indications, albeit across a small sample of workshop participants, indicated that a majority of

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[1] From Key Messages 3 and 4 of our Future Energy Scenarios 2021. Further detail can be found in 'Key Stats' of the FES 2021 Data Workbook V0.5.
[2] Network Options Assessment 2020/21. All NOA documents can be found here:
[3] This is the total cost of all reinforcements required in the System Transformation scenario up to the mid-2030s, which has the lowest total spend of the three net zero scenarios.
[4] Modelled Constraint Costs NOA 2020/21
[5] Further information on our Net Zero Market Reform programme can be found here.

stakeholders support market reform to begin now[6], while all agreed there were significant challenges and trade-offs across investment, flexibility and locational signals which would benefit from resolving holistically via market reform. We look forward to continuing to work with industry, Ofgem and BEIS to determine, evaluate, and take forward the resulting recommendations, which we expect to share by April 2022.

While holistic review of market arrangements will likely take significant time, we believe this is crucial work that needs to begin sooner rather than later. We believe it should inform the principles on which TNUoS should be based.

We agree there is a need to review TNUoS and that cost reflectivity is a key principle for ensuring efficient utilisation of and investment in the network. Trade-offs such as the natural tension between cost reflectivity and predictability of charges and between more granular cost reflectivity and simplicity are best investigated through a principles-based approach. While there may not be an agreement across industry on what this balance should be, we recommend Ofgem engage with industry and develop agreement on at least the underlying principles to be considered.

As part of this review, an important principle will be to understand the nature and purpose of TNUoS in terms of locational signalling versus cost recovery. TNUoS currently has two main purposes. The first is to send a long run locational signal to where generation and demand should locate and the second is to recover the costs of investment in transmission network assets. We agree with the economic rationale whereby if a cost is caused by the actions of a user, the user should pay. Separately to this, we support further investigation of whether demand and generation make decisions to locate based on the signals from the charging methodology, given other factors which feature in decision making and are outside of the remit of the charging methodologies. However, we do not believe diluting locational signals is a desirable outcome in its own right; the increase in constraint costs via BSUoS due to bringing electricity from areas of high generation to areas of high demand would result in overall higher system costs, which are ultimately recovered from consumers. We are open to exploring whether the link to the design and build of the system and the locational signal within the TNUoS methodology are as strong as in the past, and support this link being in scope of any review.

As part of the holistic review, it is also important to consider both the transitional period and the enduring solution for market wide half hourly settlement (MHHS) in the design of the charging methodology, such that movement of customers to half hourly settlement is not hindered or disincentivised. MHSS is expected to be a key enabler in achieving full chain flexibility[7], ensuring the tracking of value and recovery of cost across the energy system, and is expected to bring net benefits to GB consumers of between £1.6bn and £4.5bn over the 2021-2045 period.[8] Unintended effects of the current charging methodology have required modifications CMP241 and CMP247 to be raised to avoid the risk of double charging of TNUoS in the charging year the customer moved to half hourly settlement.[9]

Consideration of whole system outcomes

As reflected in our thinking on energy code reform and the role of a potential future system operator, we believe whole system thinking will be critical for achieving net zero goals.[10] In addition to considering TNUoS reform in the context of holistic market reform, we believe an important principle will involve determining what constitutes a good outcome for TNUoS on a whole systems basis, and potentially network charges as a whole. This is because, as reflected in our FES scenarios, there is no single technology solution to decarbonisation so developing a complementary mix of technologies is key to reduce overall greenhouse gas

[6] 65% of 31 responses believed reform should start now, with a further 26% before 2025. This feedback was provided via an anonymous poll during NGESO's Net Zero Market Reform Case for Change Workshops 27-29 July 2021.
[7] Ofgem's Full Chain Flexibility programme reflects the most recent Smart Systems and Flexibility plan in supporting both the supply side and demand side flexibility required to achieve net zero.
[8] The monetised impacts are per Ofgem's final impact assessment here.
[9] This was as a result of BSC modifications P272 and P322. We recognise these impacts are likely to be much smaller following changes to the transmission demand residual to be implemented in April 2023 as part of implementation of the Targeted Charging Review decision.
[10] Whole systems thinking is a key component of both future governance frameworks proposed by BEIS and Ofgem in their July 2021 consultation 'Energy code reform: governance framework'

emissions.[11] The interactions between the TNUoS charging methodology and these mixes of technologies therefore needs to be understood.

A whole system view involves coordinated thinking across the energy system for generation, transmission, distribution, and different consumers, and across the traditionally siloed electricity and gas and heat and transport vectors. In turn this supports the joining up of the physical requirements of the whole system with policy, commercial and market arrangements. Without this coordinated thinking, there is a risk of inefficient outcomes and increased costs to consumers.[12]

Assessment of options across whole systems costs and benefits provides a powerful way of resolving differing points of view across the industry. We recognise holistic market reform is likely to be lengthy and so early thinking about the data that may be needed to support this evidence base is recommended.

We recommend, given the interactions and dependencies involved, that changes to the demand side of TNUoS, the reference node, and the option to charge distributed generation TNUoS should be descoped from the AFLC SCR and combined with any future TNUoS review. We think it is important to consider the opportunity to align any future wider DUoS review and any future TNUoS review, and aim for greater consistency between transmission and distribution charging arrangements to better support whole system outcomes and to better reflect the reality of the changing energy system.

Coordination with the Offshore Transmission Network Review and Competitive Appointed Transmission Owner (CATO) regime

Across the FES scenarios, between 31 GW and 47 GW of offshore wind is connected by 2030 such that coordinated offshore network development is required to integrate the target level of offshore wind with the wider electricity system by 2030.[13] The development of the CATO regime may also fundamentally change what types of assets could be recovered under the TNUoS methodology. Where possible, we believe it is important for there to be consistency of charging between offshore and onshore generators such that investment in the onshore network complements that offshore and vice versa. We also understand there are different factors in the location, planning and consent of generation (both onshore and offshore) and are open to explore the role of how the locational element of TNUoS can provide signals in this context.

There are significant links between TNUoS reform and the offshore transmission network review, which BEIS is currently consulting on for the enduring regime. It is important that policy and regulatory goals are aligned across all programmes in order to reduce the risk of process complexity and inefficiency. For example, the offshore transmission network review consultation identifies assessment criteria to review options against. There should be alignment between these and those of TNUoS charging reform at least at an overarching principles level to ensure each workstream complements the other.

Consideration of demand

While we believe the locational elements of the generation charge should be the priority for a review, the demand side of TNUoS should also be in scope. We support descoping of the demand side of TNUoS from the AFLC SCR, along with the option to charge distributed generation TNUoS and including these in the TNUoS review scope. Historically distributed generation was treated as negative demand, and this impacts the flexible plant we have today. We agree that the use of the Average Cold Spell (ACS) to proxy for demand capacity should be reviewed. This definition is also used for the Capacity Market, further highlighting the benefit of considering the market holistically where possible.

Our control room already sees the impact of the changing relationship between demand and generation when balancing the system. The system was built for supply to meet demand while as we move to net zero demand

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[11] The UK Energy Research Centre (UKERC) landscape provides an overview of whole systems energy research, development, and demonstration in the UK, for practical examples in this context, using the wide definition of the energy system as “the set of technologies, physical infrastructure, institutions, policies, and practices located in, and associated with the UK which enable energy services to be delivered to UK consumers” (UKERC, 2009).

[12] The benefits of whole systems thinking are explored by Energy Systems Catapult’s paper ‘Systems thinking in the energy system’ which follows the early work by the Energy Technology Institute (ETI) on the Whole Energy System Analysis programme, which developed the initial whole systems modelling capability.

[13] From Key Message 4 of our Future Energy Scenarios 2021

will also need to be flexible in response to supply. Historically, peak electricity demand represented the greatest stress on the system, and this occurred during winter weekday evenings where industrial and commercial demand coincided with domestic demand, so ACS was a representative measure. While winter peak demand will continue to be challenging, particularly as electrification of heat and transport grows[14], we expect more often the greatest stress on the system will be driven by excess renewable generation.[15] An example of these conditions during 2020, the greenest year on record for the GB electricity system, was 23 May when low national demand combined with almost completely zero carbon conditions resulted in our control room taking significant action to reduce renewable generation on the grid to 80%.[16]

Demand flexibility, including storage, is critical to work with weather-driven renewable generation. Our FES scenarios indicate up to 44 GW of demand side response is needed for managing intermittent generation in a system with higher peak demand due to electrification of heat and transport compared to 6 GW today alongside up to 58 GW of electrolysis (hydrogen storage) from close to zero today, which would benefit support from market signals.

Our view is that while triads continue to be helpful to reduce demand during these periods, they can also add uncertainty to the demand forecast, potentially increasing need for reserve and balancing costs. In recent years we have also seen peak demand occur outside triad season.[17] Therefore, we are open to reviewing triads and ACS as a measure of capacity and system stress, and so the principles behind TNUoS paid by demand customers more generally, in consideration of the changing energy system. We also recognise that the locational element of TNUoS paid by demand customers is small in proportion to the demand residual, and so investigation is required to determine whether it constitutes an effective locational signal.[18] Given the relative size of the demand residual, we would expect the changes from the TCR on the transmission demand residual, namely that residual charges will be recovered as fixed charges for a particular charging band, to reduce the uncertainty around winter peak periods as there will be a much smaller incentive to shift demand away when charging is less linked to triad.[19]

Consideration of new connection types

As part of creating a methodology which is sufficiently flexible to innovation and new connection types, we believe it is important to review how different users interact with and use the transmission system as well as what markets these connection types have access to. For example, as part of the AFLC SCR we developed the understanding that distributed generation do use the transmission system and therefore should face TNUoS charges. However, transmission connected generation is currently charged based on Transmission Entry Capacity (TEC), which does not apply for the majority of DG, which opens up the question of how use of the transmission system should be measured.

New connection types could, for example, arise as a result of pathfinder projects, deployment of new renewable technologies, or the development of new storage technologies which solve a particular system need and the charging methodology should facilitate these, while also supporting competition with other technology types created to meet the same need.

For example, our FES 2021 scenarios see a need for up to 43GW of electricity storage by 2050, compared to 3.5GW available today to help balance periods of high and low renewable output. In addition, storage is expected to support system requirements such as frequency response and reserve, inertia, voltage, and

[14] Peak demands are expected to increase in all FES scenarios due to electrification of heat and transport from 58.2 GW in 2020 to between 64.6 and 69.2 GW by 2030 and between 92.4 and 113 GW by 2050. Peak demand is measured as ACS peak demand including losses. For full assumptions see FL.4 of the FES 2021 Data Workbook V0.5.
[15] This challenge is explored in our Bridging the Gap 2021 work.
[16] This case study featured in our Operability Strategy Report 2021 and provided insight into what a future zero carbon electricity system could look like.
[17] As a result we moved (in 2019) to a year-round probabilistic methodology to capture requirements at different times of the year to complement peak requirements identified from our deterministic analysis to form our Electricity Ten Year Statement 2021, which supports network investment and operational planning decisions. This represented a huge change to our modelling capabilities, going from exploring circa 22,000 winter scenarios to an additional 87,600 year-round scenarios.
[18] Table 18 of our Final TNUoS Tariffs 2021/22 shows a breakdown of the residual components of demand and generation tariffs under the current methodology.
[19] Targeted Charging Review: Final Decision and Impact Assessment

constraints. There is a question whether use of the transmission system should be defined beyond import and export of MW to ensure whole system benefits and costs are captured.

Timescales and quick wins

We understand that the timescales for holistic reform are likely to be lengthy and therefore are happy to consider quick wins as long as these do not conflict with any potential holistic reform. The challenge will be avoiding duplication of work across the quick wins and holistic reform, while maintaining the pace of work needed from the holistic reform to support net zero. Therefore, there would need to be clear quantifiable enduring benefits – ideally on a whole system basis – from progressing certain changes more quickly. For example, whether these changes would make a significant impact on investment decisions ahead of a particular CfD allocation round or support new innovative solutions crucial for net zero.

We believe the earliest feasible date for which quick win changes could be implemented is April 2023 charges, which is ambitious and highly dependent on the nature of the change. It assumes additional data sources and processes and billing system changes are not required; that changes are solely to the charging models. April 2024 charges is a more realistic yet ambitious estimate but would still require significant resourcing. Changes to our billing and invoicing systems are best considered holistically to minimise overall implementation costs which are ultimately recovered from consumers. We also are in the process of developing new system capability which will provide greater agility in delivering regulatory framework changes and enable quicker change in the future.[20]

Our experience from the Targeted Charging Review SCR and Access and Forward-Looking Charges SCR has highlighted changes in one small area often have unforeseen impacts on other areas as we explore the detail of how changes may be implemented. For example, the proposal to charge distributed generation TNUoS charges followed from understanding distributed generation uses the transmission network which raised the question whether a whole system connections process is needed to make arrangements across transmission and distribution more consistent.

Vehicle for change

We are supportive of a SCR or hybrid SCR and taskforce approach as the vehicle for change, followed by raising of the necessary code modifications for implementation. A SCR could use the existing communication channels set up for the network charging SCRs to date, such as the Charging Futures Forum.

While we are mindful of feedback from industry stakeholders concerned about the length of time the two most recent charging SCRs has taken, we believe due to the holistic nature of the reform required that a different vehicle for change will not necessarily reduce these timescales and risks missing out on the key advantage of a SCR, that it can encompass current and future modifications in its scope, bringing in existing work produced by the workgroups.[21]

We currently have nine modifications relating to the TNUoS methodology at workgroup stage[22], a substantial number for us to resource support for. One of the challenges of many open modifications for our customers is understanding the dependencies and interactions between these modifications and what the timing of these might look like for impact on the charges they pay. This significantly increases the number of queries our charging team receives from customers around understanding the methodology and the potential impact of modification interactions on their charges. An SCR will allow us to focus more resource on ensuring the methodology aligns with strategic objectives such as net zero over navigating individual changes proposed through open governance. This is reflected in Ofgem's criteria for choosing an SCR which notes the need to

[20] This reflects our latest Digitalisation Strategy, particularly section 5.4.2 on strengthening our change management, IT systems change, delivery and integration capabilities.
[21] For example, CMP271, CMP274, and CMP276 were paused and considered under the Targeted Charging Review per Ofgem's November 2017 working paper
[22] This is as of 11 November and does not include those on hold for the Targeted Charging Review, pending authority decision or in place to implement the Transmission Demand Residual (TDR) changes per the TCR decision. These are: CMP286, CMP287, CMP288, CMP315, CMP316, CMP331, CMP344, CMP375, and CMP379.

“facilitate a more efficient end-to-end process and avoid potential duplication under two separate processes.”[23]

Where a taskforce inspired engagement process within the SCR or a hybrid approach may be beneficial is in bringing in expertise and learnings from other markets to complement the expertise from the GB energy industry and CUSC parties, given the net zero challenge and potential principles are not only faced by GB transmission. Existing industry participants may have commercial interests in particular technology solutions or paths to net zero, which can be balanced by bringing in more independent expertise to ensure outcomes are aligned with the overall best interests of consumers.

We also consider a net zero world is likely to bring greater numbers of participants outside the traditional groups of generators, demand users, energy suppliers or networks and the vehicle for change should support the ability for new participants to contribute.[24] To ensure the methodology continues to align with the relevant principles and support whole system outcomes, there is a need to consider the enduring arrangements for future maintenance of the charging methodology to best reflect an energy system with both existing and new participants.

[23] From ‘Ofgem Guidance on the launch and conduct of Significant Code Reviews (SCRs)’

[24] As reflected in our Bridging the Gap 2021 final report, market participants increased by 60% in 2019 alone and by 2030 we expect there will be millions more potential participants in the market.