Scottish & Southern Electricity Networks

TRANSMISSION

BEIS' Review of Electricity Market Arrangements (REMA) Consultation

SSEN Transmission response

October 2022

About us:

SSEN Transmission, operating under licence held by Scottish Hydro Electric Transmission plc, owns, operates, and develops the high voltage electricity transmission system in the north of Scotland and remote islands.

We are delivering a network for Net Zero, connecting the renewable energy needed, and delivering the increased electrification required in society to support UK and Scottish emissions reduction targets. As a regulated business delivering critical national infrastructure, our strategic objective is to enable a just transition to a low carbon economy. Our developments and business strategy follow a stakeholder-led approach to deliver jobs and economic benefits, support greater grid resilience, create community wealth, and improve our natural spaces. To help deliver the above, SSEN Transmission is investing in a network for Net Zero, as outlined in our stakeholder-led RIIO-T2 business plan for the current price control from March 2021 – March 2026.

For more information about us, our goals and our network investment plans please visit: www.ssen-transmission.co.uk.

Delivering a resilient and efficient network for Net Zero:

The north of Scotland is home to some of the UK's greatest resources of renewable electricity and Scotland's transmission network has a key role to play in supporting delivery of the UK's Net Zero targets. We are already a mass exporter of renewable energy, with around two thirds of power generated in our licenced network area exported to demand centres in the south of Scotland and beyond.

Our north of Scotland Future Energy Scenarios indicates that at least 24GW of renewable energy will be required in the north of Scotland by 2030 to support a Net Zero pathway[1]. For context, as of the end of March 2022, we had just under 8GW of renewable generation connected to our network. Our strategic grid investments will:

- **Support delivery of 50GW of offshore wind by 2030** - by connecting our share of ScotWind offshore wind projects to the GB transmission network by 2030 and beyond.
- **Contribute to green growth** - We're planning to invest roughly £3-4bn (subject to regulatory approval) between now and 2026; increasing capacity, improving grid resilience, supporting greater electrification, and working to connect Scotland's remote islands. A further £7bn of required investment will be required in the north of Scotland by the end of the decade based on National Grid ESO's recent "Pathway to 2030" publication.
- **Support an efficient just transition** - We're creating hundreds of good green jobs, and thousands of supply chain opportunities. We're planning to double our workforce by 2026.
- **Power change** - We're the world's first network operator to be accredited for a science-based emissions reduction target, aligned to the most ambitious goal of Paris agreement and we're industry leaders in our approach to Biodiversity Net Gain on our sites.

[1] SSEN Transmission: North of Scotland Future Energy Scenarios - May 2022

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Executive Summary:

We welcome the opportunity to respond to BEIS' consultation on its Review of Electricity Market Arrangements (REMA). As the Transmission Owner (TO) for the north of Scotland, we recognise that many of the proposals contained within the consultation document do not directly impact our business. However, we feel strongly that whole system impacts from any changes to market design should also be acknowledged from a networks perspective, and we are concerned that there is insufficient focus on this topic within the REMA consultation.

The efficient delivery of Net Zero and energy security met by homegrown, affordable, low carbon electricity generation should be at the heart of regulatory and government policy. This should be embedded within decision making frameworks. Certainty of investment at this critical time, for all industry players including supply chain, along with certainty on who is delivering this investment, will be fundamental in unlocking renewable energy and decarbonisation targets at the scale and pace required. Institutional policy and regulatory reform must therefore be proportionate and robustly evidence-based to complement wider policy aims in order to not impede the ambition to reach Net Zero.

Our response is being submitted in addition to SSE's wider group response to the consultation. Our response provides more detail on the questions that relate or are likely to impact transmission network infrastructure. Similarly, SSEN-Distribution are responding on the questions relating the distribution level.

As a stakeholder-led business we also refer to the views of our generation customers in the north of Scotland who have responded separately, or via industry groups such as Scottish Renewables, to the REMA consultation. More specifically, their response to the more detailed wholesale market design and revenue support related questions. A summary of the key points we raise are detailed below:

- **We mostly agree with the overarching vision presented**. We welcome REMA's focus on delivering home grown energy security whilst facilitating the journey to Net Zero in a fair and efficient way for consumers.
- **It's important that reform is considered on a whole system basis**. This should consider short, medium, and long terms impacts and costs for all parts of the system including the GB energy networks, and any impacts on legally binding decarbonisation targets. Any market reform should create certainty for future market investment at this critical time, be robustly evidence-based and should enable the transition to Net Zero emissions.
- **There are key considerations and challenges missing from the consultation document, particularly from a grid and regulatory perspective**. This presents risk and increases cost for the successful delivery of REMA's objectives. Significant investment in the GB transmission network will be required to support future energy security and decarbonisation objectives by 2030. This is currently not recognised in the document's challenges and its absence is particularly noticeable on proposals for the introduction of Locational Marginal Pricing (LMP).
- **The assessment of transmission constraints is minimal within the case for change chapter of REMA.** The historic, current, & future levels of constraint management within GB are stated as a key driver for radical market reform options such as LMP, when in reality accelerated investment in the transmission network would directly address current constraint issues in GB, whilst enabling and reducing delivery risk for energy security and decarbonisation ambitions. We therefore believe that more comprehensive analysis is required on constraints vs transmission investment as part of the REMA process, and as such have presented our own analysis for BEIS' consideration that explores options for reform in this area.
- **Reinforcing the three mnost constrainted boundaries by 500MW additional capacity could have reduced constraint costs between January 2020 and June 2022 by £744m for a net benefit of between £477m-£695m and removed 360m tonnes of additional CO_2e emissions.**

- **Our response provides a detailed overview of the expected implications that LMP could have on future renewable energy and transmission investment in the north of Scotland.** We hope this will be carefully considered to avoid any unintended consequences in the context of energy security and Net Zero ambitions. Based on our stakeholder-led LMP analysis and building upon our recent stakeholder-led Transmission Network Use of System (TNUoS) analysis workstream, our evidence suggests that further increasing the strength of locational signals at this crucial time would be detrimental for further renewable energy investment in the north of Scotland. Market certainty and investor confidence is what is needed at this critical juncture to reach the UK's decarbonisation and energy security goals at scale and pace.
- **Our engagement with stakeholders tells us that the LMP proposals are creating high levels of uncertainty with limited transparency and understanding of what the proposals would mean for stakeholders in the north of Scotland.** 64% of our consulted stakeholders have told us that they are unsure if they support the introduction of LMP in GB, with a tie of 18% in support and 18% against, which included feedback from consumer groups, local authorities, and generators.
- **Given the high level of concern expressed by our stakeholders on the potential implementation of LMP, the risk of uncertainty on necessary investment and lack of a comprehensive evidence base that considers whole system impacts,** we question the merits of pursuing LMP at this critical juncture in the transition to net zero and the growing imperative to secure our future energy security with homegrown low carbon power. Instead, we would advocate that further whole system analysis of charging reform is undertaken by BEIS with a focus on options that would be impactful, but less disruptive, in the short to medium term. This would help to fully understand the regional and national trade-offs for future renewables investment in Scotland, and what actual benefits would be delivered for consumers by taking a principle-based approach in the context of Net Zero.
- **This point is also emphasised by The Climate Change Committee's independent Expert Group in its report, *Priorities for Electricity Market Reform and Net Zero*[2].** This report recommends that in order to avoid an investment hiatus in the 2020's, fundamental reforms such as full location-specific pricing shouldn't be considered until the critical infrastructure we need to ensure robust energy security and system decarbonisation is in place as a minimum.
- **It is critical that proposals within REMA enable and align with the UK Government's wider growth plan.** This will ensure that no unintended barriers are created for future grid or renewable energy investment, which will be the fundamental building blocks of REMA's successful implementation.
- **Market reform should also seek to address existing regulatory and policy barriers to enable its future electricity market goals.** This could be done by improving connections processes, allowing low risk strategic networks investment, clearly defining the roles and responsibilities of the Future System Operator (FSO) and improving and accelerating existing land rights and consenting practices through amends to the Electricity Act. This would further help to enable the accelerated delivery of critical grid infrastructure and unlock REMA's wider market reform objectives at this pivotal moment in the UK's energy security and decarbonisation journey.
- **Certainty of network investment, and who is delivering it, between now and 2030 will be critical.** This will help to ensure consumer efficiency, energy security and decarbonisation targets at the scale and pace required for Net Zero.

Our detailed responses to each chapter of the consultation can be found below.

[2] Climate Change Committee Expert Group: Net Zero Electricity Market Design - September 2022

Chapter 1: Context, Vision and Objectives for Electricity Market Design

1) Do you agree with the vision for the electricity system we have presented?

We mostly agree with the overarching vision presented, and welcome REMA's focus on delivering security of supply whilst facilitating the journey to Net Zero in a fair and efficient way for consumers. Achieving this balance will be critical, but also incredibly challenging due to the complexity and interconnected nature of the electricity market – reform and market design will also take a significant period of time to implement which could create additional risk and cost for Net Zero ambitions.

It's therefore important that reform is considered on a whole system basis, considering short, medium, and long terms impacts and costs for all parts of the system including the GB grid networks, and any impacts on legally binding decarbonisation targets. Reform should also create certainty for future market investment at this critical time. For example, we have concerns that some of the proposals within the consultation, such as locational marginal pricing or nodal pricing could create unintended consequences for the deployment of further renewable generation, particularly in the north of Scotland. We provide more detail on this in our response to Chapter 5 of the document.

There are also key considerations missing from the consultation, particularly from a grid perspective, which presents challenges for successful delivery of REMA's objectives. It is our view that the proposals within REMA assume that there is currently adequate transmission network capacity to support future energy security and decarbonisation objectives, when in reality significant investment will be required to efficiently support growth in generation capacity, improve resilience of supply, and reduce constraints costs for consumers which are growing significantly. Further on in our response we will refer to evidence from international market design as to how transmission network capacity build out has been managed and what can be learned from this. This point is also emphasised in the aforementioned Climate Change Committee's independent Expert Group in its report, *Priorities for Electricity Market Reform and Net Zero,* which recommends that in order to avoid an investment hiatus in the 2020's, fundamental reforms such as full location-specific pricing shouldn't be considered until the 2030's once the infrastructure we need to ensure robust energy security and system decarbonisation is in place.

It is therefore critical that proposals within REMA enable and align with the UK Government's wider growth plan and regulatory policy for future networks growth such as National Grid ESO's Pathway to 2030 document, Holistic Network Design (HND) proposals and BEIS / Ofgem's network acceleration workstreams. This will ensure that no unintended barriers are created for future grid investment, which will be the fundamental building blocks of REMA's successful implementation. In addition, REMA should also seek to address existing regulatory and policy barriers to the delivery of critical grid infrastructure to unlock its wider market reform objectives and instil market confidence at this pivotal moment in the UK's decarbonisation journey.

Certainty of network investment, and who is delivering it, between now and 2030 will be critical to unlock renewable energy and decarbonisation targets at the scale and pace required for Net Zero.

2) Do you agree with our objectives for electricity market reform (decarbonisation, security of supply, and cost effectiveness)?

The energy trilemma of is a well-established industry benchmark by means to measure progress towards Net Zero goals and we agree in principle that this is a sensible means to approach wide ranging reform such as electricity market design as per the stated scope of REMA,.

Chapter 2: The Case for Change

3) Do you agree with the future challenges for the electricity system we have identified? Are there further challenges we should consider? Please provide evidence for additional challenges

We broadly agree with the identified challenges, but also believe there are additional challenges that have not been considered in the consultation document, and that if addressed would assist in unlocking barriers to a low carbon future electricity system. While we acknowledge that the consultation is primarily focused on wider market reform proposals in the context of security of supply, cost reduction for consumers and achieving Net Zero, the pivotal role of investment in the GB grid to enable delivery of these ambitions should not be ignored or underestimated.

This will be particularly important to support future flexibility ambitions, 2030 renewable generation targets (and beyond) and improve system operability, whilst also supporting the need to reduce consumer costs over the medium to long term by targeting current network constraints. We therefore believe the following challenges should also be included when considering future reform options:

The requirement to accelerate consenting for grid - Processes for securing land rights and S37 consents risk being one of the main contributors to delays in the delivery of nationally important grid projects. Maintaining the status quo will impede delivery of the UK Government's Net Zero and offshore wind ambitions in a timely manner. We recognise that consenting and land rights processes are devolved in Scotland, but there are additional initiatives that could be taken by the UK Government to provide greater certainty and accelerate timescales for delivery of critical grid infrastructure through amends to the existing Electricity Act (such as clearly setting out the grounds upon which a local authority objection can trigger a PLI and allowing S37 consents to be varied). This would significantly help to improve timescales, reduce uncertainty, modernise processes in the context of Net Zero and address unnecessary delays. We welcome UK Government commitment to accelerate networks planning timescales as outlined within the British Energy Security Strategy (BESS) and The Electricity Networks Strategic Framework (ENSF). It is therefore important that the UK Government and Scottish Government work in alignment to achieve these ambitions in the context of Net Zero and energy security.

Timescales for the consenting of generation and supporting networks investment should be accelerated in tandem to support national offshore wind delivery targets and deliver Net Zero. We recognise that determination timescales for our projects are a matter for the Scottish Government's ECU rather than BEIS. However, to improve delivery timescales and accelerate consenting for national critical infrastructure we would advocate for the introduction of fixed maximum consenting timescales of 9 months for EIA S37 applications, and 4 months for non-EIA applications through processing agreements, with accountability for meeting measurable consenting targets. In Scotland, this is similar to current Town and Country Planning applications at Local Authority level. Furthermore, we believe Public Inquiries should be time limited to six months to reduce the risk of associated delays. In addition to accelerating current consenting processes, significant investment in planning resources (people and skills) is also urgently needed to tackle the twin climate and environmental emergencies at scale and pace.

Accelerating connections and queue management barriers - There are unprecedented levels of contracted generation on the GB transmission system, approximately a 69GW increase over the last 12 months, with further increases expected through the Crown Estate Scotland's Innovation and Targeted Oil & Gas (INTOG) leasing round. It is imperative that we ensure all schemes are progressing in a timely manner to support the delivery of Net Zero and home-grown security of supply objectives. To achieve this, we must optimise the current management of the contracted connection queue. Currently, developers have unlimited opportunities to alter their connection date without repercussions. Some schemes have delayed their connection multiple times and, due to their favourable position in the queue, are restricting customers who are behind them that are ready to progress.

Queue Management is key in helping to optimise costs borne by consumers by focusing on investments for connections that are progressing sufficiently towards their connection date. We believe this should be recognised as a challenge for the future electricity system and would therefore welcome expedition of the current modification to the Connections and Use of System Code (CUSC) to allow termination of schemes who do not meet key milestones. Alongside this, connection processes should be complementary of other market reform not contrary, to achieve this further substantial reform to the connection process is paramount to allow a “connect when ready” approach i.e. when the network capacity is available. This is critical to enabling the energy transition. We provide further information below in relation to the need for strategic investment. This is critical to enabling the energy transition.

Energy codes and reform - The current energy code process is complex and untimely to implement positive change and does not consider the critical role energy codes play in the delivery of Net Zero. While we welcome the Energy Code Review (ECR), that forms part of the Energy Bill, it is imperative that the review stays focused to deliver a clear outcome and avoid timely inefficiencies. SSEN Transmission welcomes simplification and code consolidation, however holistic consideration needs to be given to institutional reform, to ensure that codes remain the foundational rules and procedures, rather than policy, that help ensure safe and reliable network operation. This along with a binding commitment to Net Zero should be the primary objective of Code Reform.

Securities and liabilities should be reasonable and reflective of the developers’ impact on system - There are several energy code related barriers-to-entry for developers, notably of which is CUSC 15; the process for applying liabilities and securities to developers wishing to connect to the network. Currently securities/liabilities are applied on a proportional basis, reflective of the scheme’s generation capacity in proportion to the network they wish to connect to. Although there has been advances to the previous securities/liabilities’ procedure, there remains elements of CUSC 15 that require improvement to ensure the level of securities the developer pays are reflective and reasonable. For example, when reinforcement connects a month after a developer is contracted, the developer would still be liable for their proportion of the reinforcement costs up until they connect, irrespective of how many years later this is and that they had no bearing on the needs case of the reinforcement they are securing against. Further, where a reinforcement is required for system needs and not reliant on new contracted generation, the securities/liabilities for this should therefore be disassociated from the developers.

The future role and responsibilities of the FSO - The introduction of an FSO is a welcomed opportunity to provide strategic focus to the energy transition. However, there is a risk of "over-design" that loses sight of the proposed benefits. There is significant cost to institutional reform (both time and money) that can be ill-afforded, meaning robust and transparent oversight is needed. 'Strategic energy planning' should be the focus of the FSO, rather than transferring existing industry processes already done effectively by others. This could create unwelcomed disruption to the energy industry in line with the already challenging timeframes associated with Net Zero delivery. Institutional reform must be proportionate and evidence-based, avoiding any disruption to these crucial objectives.

Any delays created through the introduction of the FSO workstream will undoubtedly create risk and increase costs in reaching 2030 targets. Any change must therefore focus on key aspects of governance and ensure that it:

- **Provides transparent and timely decision-making and frameworks to maintain Net Zero pathways**
- **Retains the high-performance behaviour, benefits, and outcomes evident under the current framework,**
- **Provides clear direction on the roles and responsibilities of each participant to keep pace with a just transition including decarbonisation goals, protecting, and enhancing the natural environment and supporting local communities,**
- **Aligns with Energy Code Review (ECR) that seeks to establish a new governance framework for the energy codes.**

Certainty of network investment, and who is delivering it, between now and 2030 is critical to unlock renewable energy and decarbonisation targets at the scale and pace required. Duplications or parallel functions between the FSO and TO's will be expensive and inefficient for consumers at a time where there is already a significant skills shortage. Whilst collaboration between the ESO and TO is required, it is the TO's who are undoubtedly best equipped and have the track record, experience, expertise, and established processes to determine the future needs of their local networks, particularly network planning and project development responsibilities.

Whilst we support the FSO having a strategic role in investment recommendations, such as that which already exists in the Networks Option Assessment (NOA) and the recent HND recommendations, Ofgem must retain the role of sole decision maker for investments and dispute resolution. Delay to the workstream of implementing the FSO will be detrimental to 2030 targets. The role of the FSO should be considered in the context of further institutional reform and their desire to be a Code Manager, continuing their ESO code administrator responsibilities, under the new code governance framework proposed by ECR.

<u>**Competition in onshore transmission networks**</u> **–** We remain concerned of the risks associated with the introduction of competition in onshore electricity networks. We welcome confirmation that certain infrastructure identified in the Holistic Network Design (HND) and Centralised Strategic Networks Plan (CSNP) will be exempt from the introduction of onshore network competition, but we remain concerned at the potential for the policy to delay the achievement of 2030 targets, potential additional costs for consumers and the risks to security of supply of a fragmented network.

We are already subject to national laws that require competitive procurement of our capital investment and associated works, goods and services above specified minimum value thresholds. We apply a risk/value matrix to our procurement activities which fall under these minimum value thresholds, thus ensuring we use competitive processes, even at lower values, ensuring our expenditure is as economic and efficient as it can be. This is in line with our Transmission Standard License conditions, the System Operator Transmission Owner Code (STC) and Grid Code. Due to the essential role electricity transmission plays in meeting Government climate and renewable energy targets (and in keeping the lights on), SSEN Transmission believe there are three "red line" tests which must be satisfied prior to the introduction of any further competitive process to the regulated regime:

> **Test 1: Accelerate, not delay, the delivery of the UK's legally binding Net Zero emissions reduction targets, by facilitating delivery of the right investment at the right time and providing certainty for investors and stakeholders in the GB market.**
>
> **Test 2: Maintain security of supply, along with the high reliability standards, integration, and performance of GB's transmission networks. New entrants must be subject to the same rules, responsibilities, and obligations of incumbent Transmission Owners (TO's).**

Test 3: Provide demonstrable net benefits, lifetime cost savings, and must avoid consumer detriment by undertaking a long-term view to plan, maintain, coordinate, and operate the transmission network, and be supported by, consumers, communities and the environment, industry and electricity generators.

We feel these tests have not been met and therefore are concerned that the policy could lead to consumer detriment and impact on the ability to achieve government targets. Ofgem has also not fully considered whether the policy will lead to benefits for consumers, only that there would be low regret with implementing the necessary framework to support the policy. In a report we commissioned, based on evidence from the benefits of the RIIO framework, analysis from Oxera arrived at a central case where competition will result in additional cost to consumers. We encourage BEIS and Ofgem to ensure there are robust safeguards in place to ensure high standards are maintained, with the establishment of clear roles and responsibilities; that tender evaluation economic assessments consider all costs (i.e., whole life); and delays to investment are avoided.

There is also a clear need to learn lessons from the energy retail market and it is vital that we do not repeat these risks with national infrastructure. These failings act as a reminder of the need to carefully consider the applicability and consequences of competition in the transmission sector. Certainty of investment at this critical time, for all industry players including supply chain, along with certainty on who is delivering this investment, will be fundamental in unlocking renewable energy and decarbonisation targets at the scale and pace required.

Allowing low risk strategic investment in electricity transmission network infrastructure that is required to meet Government targets- The current regulatory process, particularly for project assessment and approval of needs cases, is not designed for efficient whole system and timely delivery in the context of Net Zero and prolongs the already tight timeframe to deliver our collective energy ambitions. By allowing elements of strategic investment on the onshore transmission network (similar to the approach for offshore networks that are part of HND), it would enable the delivery of key reinforcements with minimal risk of stranded assets. Such high-risk investments are not speculative and are essential to achieve Net Zero pathways, this is not anticipatory investment but enabling works.

Recognising the impact of locational signals - As the Transmission Owner for the north of Scotland we play a key role in system operability, transporting the vast natural resources of the north of Scotland across GB to where energy is needed. Locational decisions and market mechanisms that drive these decisions have the potential to materially impact our network and future planning, creating uncertainty and potential risk to meeting Net Zero goals and use of the high natural resource capabilities of the north of Scotland to their full potential.

The locational signal case for change literature review on page 32 of the REMA consultation document outlines that the current locational signal created through transmission network use of system (TNUoS) charges are difficult for generators and investors to forecast, which is a position we agree with. We have been calling for reform in this area, not just regarding volatility and uncertainty, but also to modernise the charging methodology principles which date back to the 1990's and are not suitable for a decarbonising electricity system. These underlying principles relate to a time when locational signals incentivised gas-based generators to connect as close to demand as possible. In a time of decarbonisation and with legally binding Net Zero goals fast approaching, these principles do not reflect the future of renewable generation we are aiming for. This form of locational signal harms the potential to unlock renewable generation from areas of high natural resource such as the north of Scotland who in turn have to pay the highest TNUoS costs in GB and Europe, whilst areas closer to demand receive negative charges as part of this system[3].

The consultation also refers to increasing strain on the network due to a lack of transmission capacity, which in turn has led to significant balancing costs as National Grid ESO increasingly has to curtail and constrain generators through the Balancing Mechanism (BM) in order to rebalance the system. The consultation states that renewable generation investment has outpaced network reinforcement: the increase in constraint costs is not surprising after long periods of significant expansion of generation capacity ahead of commensurate transmission expansion, under the Connect & Manage initiative[4]. The consultation also acknowledges on page 32 that decisions for where to build renewable assets are primarily driven by the availability of load factors given the key importance of this factor in business cases. We welcome the confirmation on recognition of this point within the consultation.

International markets such as Texas and New Zealand which have locational marginal pricing have confirmed the importance of natural resources and load factor availability in generation siting decisions. Anecdotal evidence from studying these markets has shown that siting decisions corelate to load factor availability. Onshore wind in Texas has sited based on high wind load factors available in the west of the state despite nodal pricing signals incentivising siting closer to demand in the east[5], and in New Zealand geothermal generational build out has increased over the last 20 years in areas of high load factor such as the Taupō Volcanic Zone[6]. These case studies also acknowledge that the technology type of renewable assets is also a key factor in determining the ability to respond to locational signals. Evidence from international markets has shown that flexible smaller scale technologies such as solar are the only type that can reactively respond to increasing the strength of locational signals.

4) Do you agree with our assessment of current market arrangements / that current market arrangements are not fit for purpose for delivering our 2035 objectives?

We believe that certain aspects discussed within the case for change does not fully assess the impact of certain current market arrangements. In particular, we believe that the consultation does not fully capture the scale of expected constraint costs within the GB system over the next few years. Constraint costs, resulting as a result of a lack of transmission capacity, are quoted within the consultation as totalling £1.2bn in 2021. We feel it worth noting that this figure is likely to be much larger in the future than is shown throughout the case for change. National Grid ESO's latest forecast from October 2022 predicts that constraint costs for the year 2023 are anticipated to reach nearly £3bn[11]. It should also be noted that managing the cost of constraints in the Balancing Mechanism is currently levied through Balancing Service Use of System (BSUoS) charges that are paid by generation and demand. However, as of 1st April 2023 this will change and the cost will be levied solely on demand, ultimately meaning consumer bills, as decided by Ofgem via code modification CMP 308[12].

Figure 4: Network Constraint Cost page 33, within the document is an out-of-date publication from National Grid ESO published in 2021[13] and relies on Network Options Assessment (NOA) that are now

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[3] SSEN Transmission: Transmission charges, an overview of charges for use of the GB transmission system - February 2021
[4] Department of Energy & Climate Change: Government Response to the technical consultation on the model for improving grid access - July 2010
[5] Regen: Wild Texas Wind Regen Insight Paper on Locational Marginal Pricing - June 2022
[6] Ministry of Business, Innovation & Employment: Energy in New Zealand 21 - August 2021
[11] National Grid ESO: Monthly BSUoS Forecast Summary - October 2022
[12] Ofgem: CMP308 Decision and final impact assessment - April 2022
[13] National Grid ESO: Modelled Constraint Costs NOA 2020/21 - June 2021

old. The NOA 2020/21 from which this modelling is based has since been surpassed by two NOA assessments with the most recent being the NOA 2021/22 refresh[14]. If constraint costs are being used as a primary reason to reform locational signals, then it is essential that up to date and accurate modelling is used. The model presented in the case for change is based on out-of-date transmission plans, and the costs for constraints within the model are already expected to be higher next year than what the model presents.

We also welcome the analysis of constraint management and redispatch containing carbon aspects as well as fiscal aspects, as mentioned on page 33. The scale of the carbon impact from managing transmission capacity constraints through market mechanisms such as the Balancing Mechanism is extensive and counterproductive to legally binding Net Zero goals. The majority of generation capacity "constrained off" is renewable wind from Scotland, that lost energy is replaced with carbon intensive generation that tends to be in the south of England and close to demand centres[15]. Enabling the increased quantity and pace of transmission network capacity through decreased regulatory barriers, as mentioned in our Chapter 1 response, would assist with this issue that sees carbon intensive generation prioritised over clean, cheap renewable energy.

Given the importance rising constraint costs have in terms of influencing policy and with our comments above in mind, we have conducted our own analysis to assess how industry has arrived in this position. This will help inform future conversations around constraint costs and network reinforcement in the Energy Trilemma context. Please find our SSEN Transmission – LCP report: *'Reinforcement Vs Constraint Analysis'* attached as Appendix A which supports our SSEN Transmission response to REMA.

The first segment of our report focusses on the volume of energy managed in the Balancing Mechanism (BM) and uses a mixture of publicly available National Grid ESO data and Elexon BM data spanning from January 2020 through to June 2026. When assessing thermal constraint (when the amount of energy that would flow naturally from one region to another exceeds the capacity of the circuits connecting the two regions[16]) data provided by NGESO, broken down by boundary, evidence shows that the cost of managing thermal constraints alone totals £2.5bn over the two-and-a-half-year period. Furthermore, 76% of these thermal constraint costs accounted for transfers from Scottish, areas of high renewable resource, to English boundaries, where the majority of demand sits (SSE-SP, SCOTEX, SSHARN). The geographical location of the boundaries used by NGESO to present this data is shown in Figure 1[17]. Figure 2 shows the above mentioned £2.5bn cost broken down by month and also by individual boundary cost.

[14] National Grid ESO: Networks Options Assessment 2021/22 Refresh - July 2022
[15] Drax / LCP: Renewable curtailment and the role of long duration storage - May 2022
[16] National Grid ESO: Thermal Constraint Management - October 2022
[17] National Grid ESO: System Constraints - October 2022

Figure 1: Map of constraint boundaries

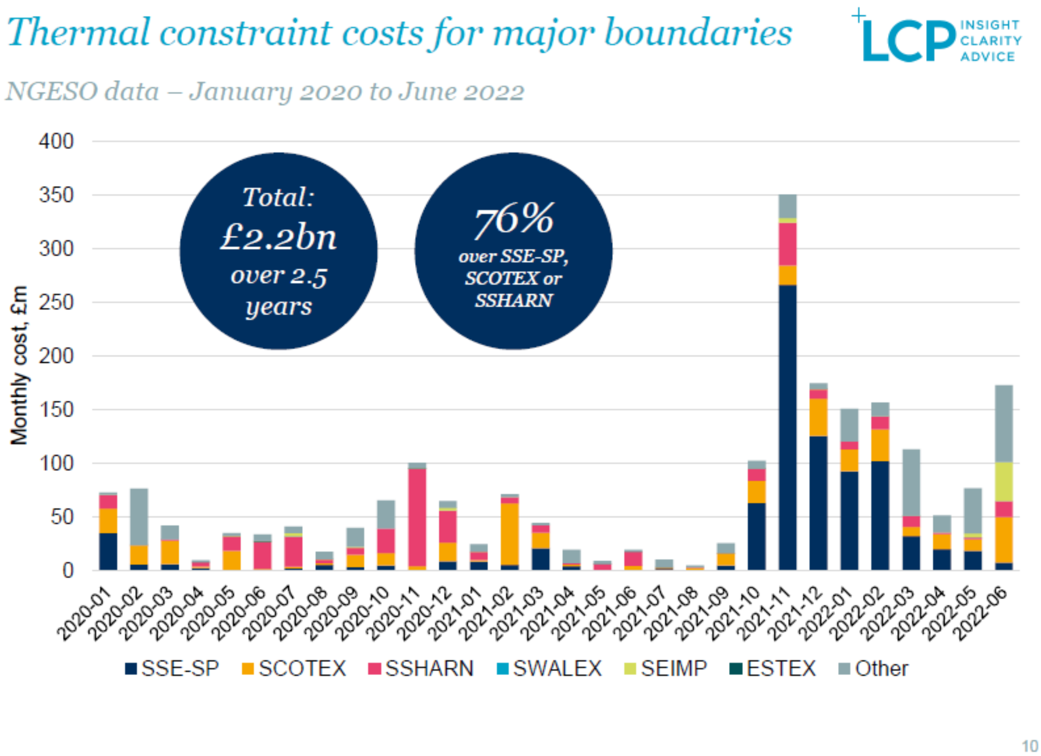

Figure 2: Thermal constraint costs for major boundaries

In addition to the high cost of managing thermal constraints, there is also the need to consider the technology types used to rebalance the system and maintain system operability. The report analysis has shown that Combined Cycle Gas Turbines (CCGT), as expected, is the dominant technology type used in the BM offer process where generators are redispatched to ensure demand can be fulfilled. As a result of CCGT being a fossil fuel-based form of generation type, we were able to calculate a carbon emission and cost associated with the balancing actions taken over the same two and a half year period. The analysis shows that an additional 3.6m tonnes of carbon dioxide emissions have been generated due to the management of thermal constraints in GB using current practise. When applying BEIS' cost to society carbon appraisal values to the 3.6m tonnes of carbon dioxide emissions, this worked out as £886m worth of damage to society over the 30-month period in question. Given the closeness of impending Net Zero goals, managing system operability in such a manner is at complete odds with the objectives we are striving to deliver for society. Figure 3 illustrates these carbon impacts from managing thermal constraints, broken down by month and technology type.

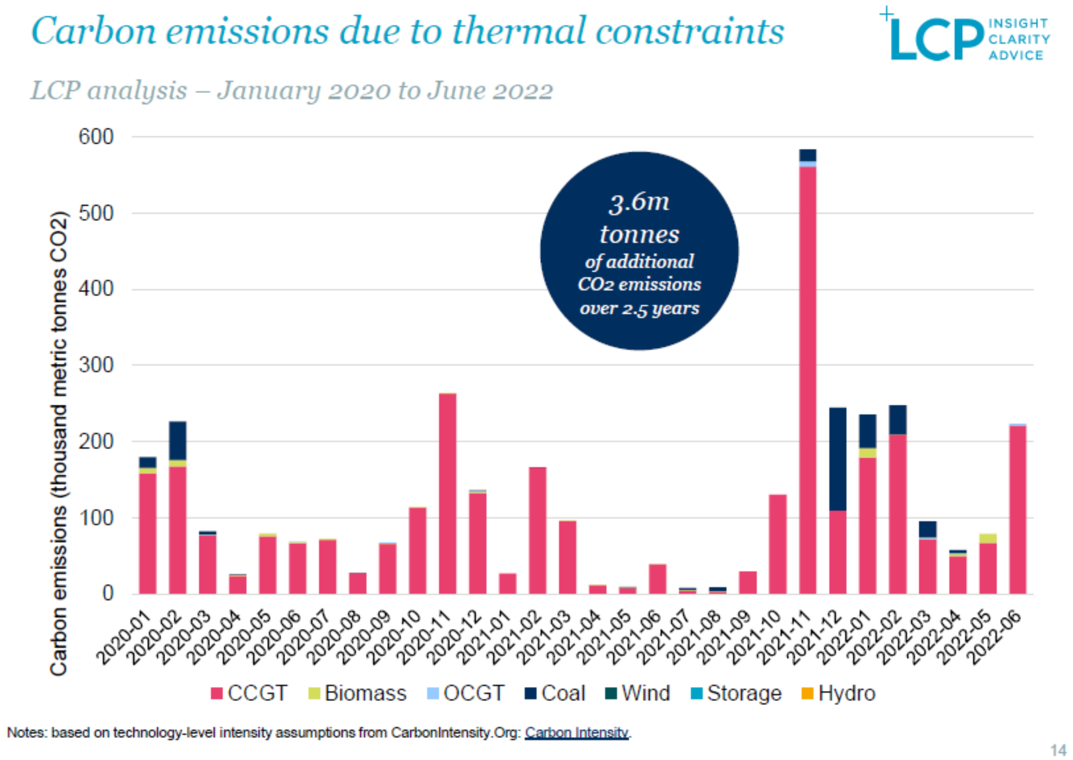

Figure 3: Carbon emissions due to thermal constraints

Further analysis was conducted that examined how the impact of managing the current constraint process could be altered through different scenarios including increased available transmission capacity on the system, which would alleviate the network stress levels and the associated pass-through balancing costs. This analysis contains caveats which are fully explained in the attached Appendix A, but the principles are based on the same six NGESO boundaries as outlined in Figure 1 previously. The findings of this study showed that by adding an additional 500MW of capacity at the three boundaries implicit in the transfer overall from Scotland to England (SSE-SP, SCOTEX, SSHARN) whilst adjusting for policy support no longer required, that savings would be £744m compared to what had been paid to manage this constraint issue historically. Figure 4 shows this, breaking the savings down to each boundary involved in the capacity increase between Scotland and England. It should be noted that this saving figure is gross and is not inclusive of the cost of making 500MW of extra transmission capacity available at the three boundaries mentioned previously.

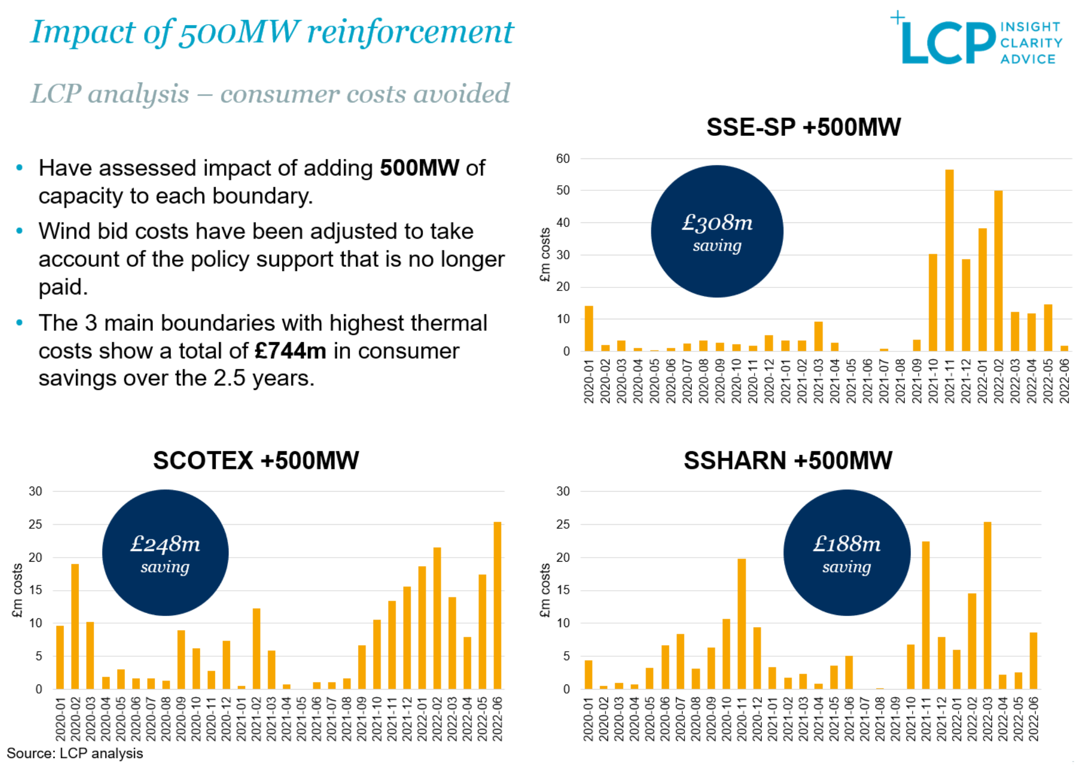

Figure 4: Impact of reinforcement on thermal constraint costs

This analysis goes on to calculate the net savings as a result of the additional 500MW capacity available, by quantifying the cost of making this extra capacity available. This net calculation considers the cost of the three 500W reinforcements under three different scenarios:

1. NOA approach which uses total cost of all NOA 2020/21 reinforcements aligning with NGESO published boundary capability projections.
2. TNUoS approach that assumes adding 500MW of 100% load factor generation capacity to a TNUoS zone north of each of the three boundaries in question.
3. Assumed two HVDC connections (one for each major boundary) using cost data for HVDC connections from relevant regions, including link-specific expansion factors from NGESO TNUoS model.

Further details on caveats for calculating these figures are available in Figure 5 below. From calculating the cost involved in making the extra capacity available, the final net savings figure can now be calculated and are also presented within this figure. The findings show that regardless of methodology applied to calculating the cost of making 500MW capacity available at each boundary, each option provides significant savings in net terms when compared to the cost of managing constraints through the current process, where the impacts of inadequate transmission capacity are managed through the redispatch process within the BM.

Benefits vs cost of reinforcement

LCP analysis

Estimated net savings under three different approaches to estimating the costs of reinforcement.

Reinforcement cost approach	Approach	Caveats	Consumer cost saving, 3 x 500MW reinforcements, 2.5yr	Estimated cost of 3 x 500MW reinforcements, p.a.	Estimated cost of 3 x 500MW reinforcements, 2.5yr	Implied net consumer saving over 2.5 years
1) NOA approach	• Using total cost of all NOA 2020/21 reinforcements aligning with NGESO published boundary capability projections • Have only included boundaries which are clearly distinct to limit double counting of added boundary capability • Calculating total cost per MW of adding boundary capacity	• Includes reinforcements which do not add to boundary capability • Includes capability being added across wide range boundaries, not just 3 (some reinforcements will affect multiple boundaries) • May not be comprehensive list of all reinforcements required by 2034	£744m	£20m pa	£49m	£695m
2) TNUoS approach	• Added 500MW of 100% load factor generation capacity to a TNUoS zone north of each of the 3 boundaries • Used current TNUoS charges for relevant generation zones	• Likely some double counting eg North Scotland costs will include reinforcements further south • Some of the generation added will be met by demand north of boundary	£744m	£70m pa	£175m	£569m
3) HVDC approach	• Assumed 2 HVDC connections (one for each major boundary) • Used cost data for HVDC connections from relevant regions including link-specific expansion factors (from NGESO TNUoS model)	• Costs used are highly project-specific in practice • May not need 2 separate 500MW lines to achieve capability	£744m	£107m pa	£268m	£477m

Source: LCP analysis, NGESO published information in NOA and TNUoS models

Figure 5: Benefits vs cost of reinforcement

We hope that the above analysis and the attached Appendix A is useful for BEIS when considering the case for change. The case for change outlined in Chapter 2 is the foundation for which market reform options in the rest of the REMA consultation are built upon. We therefore believe it imperative that the scale of issues within current market design, such as constraint management and the pass-through impact on the Balancing Mechanism, are completely understood. We feel that it is essential the most accurate review of current state of play market conditions is carried out to ensure that in the end the optimal decisions to move us forward and achieve Net Zero goals, whilst delivering the whole system thinking that is required as we rapidly progress with decarbonisation at scale, is achieved.

Chapter 3: "Our Approach"

5) Are least cost, deliverability, investor confidence, whole-system flexibility and adaptability the right criteria against which to assess options?

We agree in principle with the proposed criteria. However, options should also be assessed in line with meeting established strategies and workstreams such as the British Energy Security Strategy and National Grid ESO's Pathway to 2030 publication. Instilling investor confidence will be critical to ensure the UK receives the investment it needs to build a robust, home grown and decarbonised future energy system.

When considering least cost options, we also request that this considers the impact not just on current consumers, but also future consumers bills and wider societal impact. Lack of investment in critical infrastructure now based on current cost benefit analysis could have much more adverse consequences for future consumers, system operability and the environment in the medium to long term. Given the scope of REMA is to assess electricity markets through to 2050, it is imperative that short term improvements do not worsen issues further down the line.

6) Do you agree with our organisation of the options for reform?

The proposed organisation of reform options appears sensible, it is imperative that any policy reform is fully assessed in order to understand the passthrough impacts that may occur from reforming a large topic such as wholesale markets and therefore what this means for flexibility options.

7) What should we consider when constructing and assessing packages of options?

When assessing packages of options, we would welcome transparency in decision making and on the evidence base which leads to decision making. We'd also welcome greater recognition of the GB network's role and any potential impacts when assessing potential reform package options, taking a whole system approach at every available opportunity.

Chapter 4: Cross-cutting Questions

8) Have we identified the key cross-cutting questions and issues which would arise when considering options for electricity market reform?

Given this chapter discusses philosophical questions and focuses more on establishing joined up thinking across market reform areas as opposed to explicitly recommending market design changes, we agree in principle that cross cutting questions need to be given appropriate thought and analysed through an established framework at the next stage of REMA. Chapter 5 (a Net Zero wholesale market) presents more opportunity to comment on the specific details of implementing nodal market design, we refer to our comments on this chapter for more detail on this topic.

9) Do you agree with our assessment of the trade-offs between the different approaches to resolving these cross-cutting questions and issues?

We refer to SSE's group response in relation to the questions on the cross-cutting issues and trade-offs.

10) What is the most effective way of delivering locational signals, to drive efficient investment and dispatch decisions of generators, demand users, and storage? Please provide evidence to support your response.

As a TO, we are particularly interested in locational signals given the associated impact on transmission planning for the north of Scotland network. We acknowledge the additional thinking that has been given to locational signals in this chapter of the consultation and welcome the exploration of alternative mechanisms that implement locational signals to varying strengths and are an alternate option to extreme change such as nodal pricing. Chapter 5 (a Net Zero wholesale market) presents more opportunity to comment on the specific details of implementing nodal market design, we refer to our comments on this chapter for more detail on this topic.

We welcome the acknowledgment on page 60 that the associated impacts from implementing differing types of locational signals can be extensive, particularly from a transmission perspective. We agree that any changes to locational signals should be considered in policy reform work streams from Offshore Transmission Network Review (OTNR) to Future System Operator (FSO).

11) How responsive would market participants be to sharper locational signals? Please provide any evidence, including from other jurisdictions, in your response.

Given this chapter discusses philosophical questions and focuses more on establishing joined up thinking across market reform areas as opposed to explicitly recommending market design changes, we agree in principle that cross cutting questions need to be given appropriate thought and analysed through an established framework at the next stage of REMA. Chapter 5 (a Net Zero wholesale market) presents more opportunity to comment on the specific details of implementing nodal market design, we refer to our comments on this chapter for more detail on this topic.

12) How do you think electricity demand reduction should be rewarded in existing or future electricity markets?

We refer to refer to views shared by our generation customers, such as Scottish Renewables. In relation to the questions on the cross-cutting issues and trade-offs.

Chapter 5: A Net-Zero Wholesale Market

13) Are we considering all the credible options for reform in the wholesale market chapter?

For specific questions in relation to proposed wholesale market design we refer to views shared by our generation customers, such as Scottish Renewables.

14) Do you agree that we should continue to consider a split wholesale market?

For specific questions in relation to proposed wholesale market design we refer to views shared by our generation customers, such as Scottish Renewables.

15) How might the design issues raised above be overcome for: a) the split markets model, and b) the green power pool? Please consider the role flexible assets should play in a split market or green power pool – which markets should they participate in? - and how system costs could be passed on to green power pool participants.

For specific questions in relation to proposed wholesale market design we refer to views shared by our generation customers, such as Scottish Renewables.

16) Do you agree that we should continue to consider both nodal and zonal market designs?

As a stakeholder-led business, we share the strong concerns voiced by our generation customers on proposals for introducing LMP and the impact this could have on the required deployment of renewable energy projects in the north of Scotland. Our network region will be critical to the UK's Net Zero goals, abating up to 10% of the target despite only representing 2% of the UK's population[18].

Nodal market design & current locational signal issues - Locational signals are currently already present within GB electricity markets through TNUoS, and the move to LMP would see a much sharper version of locational signal introduced. Our generation customers and wider stakeholders in the north of Scotland consistently tell us that charges for transmission access, as well as uncertainty about future charges, are acting as a blocker to the commercial viability of renewable energy projects. As part of our stakeholder led advocacy priorities, we have been calling for urgent reform to the current transmission charging methodology for some time. Whilst we recognise and welcome Ofgem's launch of the TNUoS Task Force and promised future review it is important that BEIS consider the current challenges as a result of TNUoS as part of wider market reform.

Our stakeholder led TNUoS analysis demonstrates that locational signals do not create a fair and enabling system for consumers and creates additional risk and cost to the deployment of renewable energy at a critical time in GB's decarbonisation journey. Over 80% of our engaged stakeholders told us that TNUoS acts as a barrier to the delivery of their renewable projects in Scotland. Recent analysis carried out by NERA Economics commissioned by Ocean Winds shows that by 2030 the volatility of TNUoS alone could increase consumers bills by up to £390m per year[19]. We are yet to see through our analysis how the current methodology for generation TNUoS benefits consumers. We expect that the high cost, volatility, and unpredictability is likely to be increasing costs for consumers. It is key to note that although TNUoS is split into generation and demand, there is a common misconception that the

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[18] SSEN Transmission: Getting To Net Zero - November 2021

[19] This document is not available in the public domain, but we can request a copy to share with BEIS if this would be useful.

revenue recovered stops there. Generation TNUoS has to be built into the cost margins of each project, these costs flow through the market to the supplier and eventually are paid by consumers, resulting in consumers paying both generation and demand TNUoS at one point or another. The volatility and unpredictability of generation TNUoS significantly increases the risk and cost for generators, through CfD subsidies as well as other associated costs, and we expect that this is increasing consumers bills in the long run.

Evidence suggests that locational charging signals make Scottish projects less competitive in the CfD process, with successful projects raising prices for consumers to account for additional cost, and lower priced bidders elsewhere in GB benefiting by being brought up to the cleared strike price. Anecdotal evidence suggests that Scottish developers are adding on roughly £10 per MWh in their bids to combat this increased cost, alongside the volatility and unpredictability of TNUoS – this ultimately ends up on consumers bills. Although the renewables pipeline appears to be strong in Scotland, it doesn't mean that all projects will actually proceed / be delivered due to a chicken and egg situation - developers don't find out about what their charges will be until they go through the connections process with their projects and even then, future forecasting is uncertain and can make projects commercially unviable.

Introducing stronger locational signals through LMP approach would exacerbate this issue and create further market uncertainty at a time when realisation of the UK's Net Zero targets should be at the heart of policy decision making. As we move towards a zero-emission electricity system, charging signals should support the essential diversity in the location of electricity generation, in the places that have the very best renewable resource, to ensure we continue to have efficient, resilient and robust security of supply for GB consumers.

Stakeholder feedback - As a stakeholder-led business, we hosted an external webinar to discuss stakeholder views on LMP and understand potential impact in the north of Scotland, using our own analysis on LMP as a guide for discussion. Held on Tuesday 4th October, the webinar was attended by over 90 external stakeholders across the north of Scotland and included representatives from several local authorities, consumer groups, industry and economic development bodies and many of our generation customers.

64% of attendees that participated in polling during the webinar stated that they were unsure if they supported the introduction of LMP in GB, with a tie of 18% in support and 18% against. Verbal feedback consisted of questions as to how the introduction of LMP would work in the north of Scotland including that the proposals are very complex, that greater transparency is needed on pricing, that most generation technologies have little ability to respond to locational signals, that it would have a negative impact on future renewables investment / Net Zero delivery and that not enough modelling has been undertaken to properly assess the whole system benefits and limitations of its implementation.

Given the high level of uncertainty shared by our stakeholders on the implementation of LMP, we would advocate that further comprehensive analysis is undertaken to fully understand the trade-offs for future renewables investment in Scotland and what actual benefits would be delivered for consumers taking a principle based, whole system perspective which is not just based on the wholesale price for electricity. A full summary report of the webinar feedback will be published in due course which we will share with BEIS once published.

The economic theory underpinning nodal pricing suggests that north of Scotland generators would be expected to clear reduced wholesale prices when compared against current market arrangements - this would potentially put Net Zero goals at risk. Given the increased load factors and natural resource availability in the north of Scotland, it seems a counterproductive way to explore how to best achieve Net Zero. North of Scotland Future Energy Scenarios (NoSFES) tell us that a significant capacity of renewable generation will be required from the north of Scotland; 24-31GW by 2030 and 49-52GW by 2050 in order for GB to meet its legally binding Net Zero targets[20]. Considering this, we have concerns that the implementation of zonal or nodal pricing may mirror or worsen the current issues of TNUoS which result in high, volatile, and unpredictable costs. If such issues are not addressed through market reform, we foresee this impeding the development of renewable generation in the north of Scotland, where there is rich renewable resource.

The concerns noted above are further heightened when considering the ScotWind announcements from earlier in this year. The result of ScotWind was a pledge of a further 25GW from the north of Scotland over the coming decades as a result of Crown Estate Scotland's land leasing process[21]. Investment decisions for the north of Scotland were based on current market design alongside other components such as land, resources, consenting and capacity. When considering market reform, it is important that these elements are considered holistically, and full consideration is given to creating a market where areas with the best renewable resource are incentivised to utilise the abundance of natural resource availability.

17) How might the challenges and design issues we have identified with nodal and zonal market designs be overcome?

LMP and Liquidity - One aspect that must be considered when assessing nodal pricing is the impact of alterations to wholesale market design on liquidity as referenced on page 64. Advocacy that has been presented supporting the idea that nodal markets create increased market liquidity[22] may not account for a variety of factors. Others nodal markets with high liquidity levels such as the PJM Eastern interconnection grid in North America may not necessarily see the same level of liquidity translate into GB markets. Furthermore, other Nodal markets in North America such as the MISO the Midcontinent market see significantly reduced levels of liquidity when compared to PJM[23].

It is important to recognise that the anticipated market behaviours and detail of future hedging products that will become available are difficult to predict. Generators "constrained off" under current market design would trade less frequently in a nodal market, given the change to dispatch operations and the move to central dispatch from self-dispatch. The system operator would decide dispatch order, so generators who previously enjoyed freedom in a self-dispatch market would be more restricted in their activity. This would theoretically reduce the volume of hedging instruments traded and reduce the ability of renewable generators to express the full details of their costs[24]. These factors coupled with the lack of information available on future GB hedging tools, in terms of the length of time and the suitability of the scope of products, mean that reduced market liquidity is just as plausible.

There is also minimal acknowledgement of the extensive level of complexity associated with building a new trading market from the ground upwards. We would anticipate that ensuring the correct mechanisms are in place to facilitate free trading of Financial Transmission Rights (FTR's) would be just as complicated as the modelling of nodal prices, introducing a nodal market in Texas took over seven

[20] SSEN Transmission: North of Scotland Future Energy Scenarios - May 2022
[21] Crown Estate Scotland: ScotWind offshore wind leasing delivers major boost to Scotland's Net Zero aspirations - January 2022
[22] FTI Consulting: Operation Market Design, Dispatch and Location - January 2022
[23] London Economics International: Review of PJM's Auction Revenue Rights and Financial Transmission Rights – December 2020
[24] University of Cambridge: Central versus self-dispatch in electricity markets - January 2018

years and ended up costing four times as much as initially expected rising from $125m to $550m[25]. New Zealand similarly went through an extensive reform period when nodal pricing was introduced in 1998, with significant delay and also varying levels of success in terms of forward electricity liquidity[26]. We would also expect to see increased analysis surround the practicalities of what FTR's would look like in a GB context in terms of length; if they are only sold on one year ahead terms then liquidity levels would remain low. Furthermore, the shape of product will be crucial given generators will require specific products that match the profile of their expected output. If this is to be the mechanism to appease concern of investment within the north of Scotland in particular, then we would welcome further analysis in this area.

LMP and future transmission investment - The consultation references on page 70 that nodal pricing would resolve network congestion, and as a result that this would provide savings to consumers due to lack of constraint payments provided to generators. It is important to note that in nodal systems the impact of congestion and transmission constraints do not disappear but are instead shifted into wholesale prices and further subsides which all impact consumer bills in the long run. These prices have the potential to differ extensively from location to location and in certain scenarios can reach extreme cost levels. During the February 2021 Storm Uri in Texas nodal prices reached $9,000 / MWh which was the system price cap, and the total value of electricity over the week of the storm was $59bn[27]. We believe it therefore essential that robust cost benefit analysis and impact assessment is carried out to ensure the perceived benefits of reducing constraint payments is assessed against potential extreme nodal price volatility present within such market design.

Transmission capacity is always going to be required and the introduction of nodal pricing should not be used as an alternative to this. It is vital that transparency and thought is given as to how transmission capacity build out would be managed when moving to a nodal system. Evidence from North American markets suggest that the mechanisms within a nodal and centrally dispatched system have been generally ineffective at building out transmission capacity. They concluded that forward looking transmission capacity build out should be the focus for their energy markets as they move forward to a Net Zero future[28]. We would welcome further analysis as part of the REMA consultation that explores the relationship between transmission capacity & nodal pricing signals, and how the cost benefit analysis interdependencies between these two concepts would work in a nodal system.

Lack of constraint payments available as a result of deficient transmission capacity may also further increase the potential of a renewable generation investment hiatus, as shown by Competitive Renewable Energy Zone (CREZ) legislation utilised in Texas in the early 2000's. This policy choice was designed to ensure that enough transmission capacity was built ahead of generation connection in order to reduce the likelihood of constraints occurring, and the result of this policy correlated with increased renewable generation investment as a result of increased transmission investment. In a nodal system where constraint payments were not available and transmission capacity was scarce, investment in renewable generation decreased and did not take advantage of nodal price signals[29]. This type of

[25] Journal of Regulatory Economics: Did the introduction of a nodal market structure impact wholesale electricity prices in the Texas (ERCOT) market? - January 2014
[26] University of Otago, Dunedin, New Zealand: Liquidity and Risk Premia in the New Zealand - May 2016
[27] Potomac Economics: 2021 state of the market report for the ERCOT electricity markets - May 2022
[28] Federal Energy Regulatory Commission: Building for the Future Through Electric Regional Transmission Planning and Cost Allocation and Generator Interconnection - May 2022
[29] The University of Texas at Austin: Everything's Bigger in Texas: Evaluating the Success and Outlook of the Competitive Renewable Energy Zone (CREZ) Legislation in Texas - August 2018

anticipatory transmission investment resulted in increased wind generation investment at the same time reducing wind curtailment from 17% to 1.2%[30].

A key implementation challenge we foresee will be alterations made to the methodology used by National Grid ESO and Ofgem for green lighting new transmission investment in a nodal market. Within current market design, there are several key documents associated with new transmission investment: Network Option Assessment (NOA), Electricity Ten Year Statement (ETYS), Offshore Transmission Network Review (OTNR) & Holistic Network Design (HND). Each of these complex workstreams will influence decisions that are made to ensure the optimal development of the transmission network to deliver Net Zero. It is therefore crucial that the interdependencies and wide-reaching impacts of these benchmarks for assessing transmission investment will be given extensive consideration within any new market design proposals. The current cost benefit analysis compares the cost of new network build versus the benefits created over the lifetime of a new asset, such as the pass-through impact on redispatch or constraint management and doesn't measure carbon impact of redispatch processes[31]. Given the impact on this area driven from the fundamental changes associated with nodal pricing's implementation, we are concerned as to how this will be captured in the updated methodology for transmission investment assessment cases. We would also expect inputs to the afore mentioned cost benefit analysis process to change, making modelling more complicated. This is due to the arrival of new inputs that will need to be captured, such as the forecasting of future price spreads at potentially 1000's of nodes across GB. With this in mind, it is essential for full transparency regarding how the methodology and decision-making process underpinning decisions for new transmission investment will be applied in a nodal market.

Deliverability of LMP - Considering the time scale associated with other industry reform work streams such as the Access & Significant Code Review, which is yet to complete and has created new Ofgem works streams as a result[32], we see implementing nodal pricing as taking a significant length of time. Given the scale of change required to facilitate a nodal market and the length of time that would be required, we are doubtful if such a radical change will incentivise or provide stability for renewable investment and network investment. We believe that the current timeline for delivery estimated in National Grid ESO's Net Zero Market Reform project of 2027, is not fully aligned with the time that industry anticipates such a change would take[33]. There will be the likely risk of a variety of factors such as legal challenges, procurement issues and general delays to the process.

Another aspect of deliverability we feel creates significant risk to industry is the future of TNUoS within a nodal market. There is already reform ongoing that must be accounted for[34]. Further, there is currently limited available evidence as to what would happen to TNUoS given that nodal pricing encompasses the locational signal created by TNUoS. If it is assumed that generation revenue recovered through locational TNUoS shifts to revenue earned from the wholesale market, then there is range of scenarios that must be properly tested, benchmarked, and analysed. Possibilities such as using the congestion rents earned by National Grid ESO as the settler of market participation through central dispatch in a nodal system, or the potential revenue created from financial surplus acquired from facilitating the auction of FTR's, are complex alternatives that will require significant forecasting and resource. The recovery mechanisms for collecting regulated allowed revenue as a transmission owner is therefore open to extensive risk. We believe that reforming TNUoS after the implementation of nodal pricing will be a vast task and is another

[30] Jeonbuk National University: Market Impacts of a Transmission Investment Evidence from the ERCOT Competitive Renewable Energy Zones Project - June 2020
[31] National Grid ESO: Networks Options Assessment Methodology - July 2021
[32] Ofgem: Access and Forward-Looking Charges Significant Code Review Final Decision - May 2022
[33] National Grid ESO: Net Zero Market Reform Phase 3 Conclusions - March 2022
[34] Ofgem: Transmission Network Use of System Charges a Task Force Update - May 2022

factor as to why the current deliverability timelines do not appear completely representative of the scale of challenge.

18) Could nodal pricing be implemented at a distribution level?

For specific questions in relation to proposed wholesale market design we refer to views shared by our generation customers, such as Scottish Renewables.

Do you agree that we should continue to consider the local markets approach? Please consider the relative advantages and drawbacks, and local institutional requirements, of distribution led approaches.

For specific questions in relation to proposed wholesale market design we refer to views shared by our generation customers, such as Scottish Renewables.

Are there other approaches to developing local markets which we have not considered?

For specific questions in relation to proposed wholesale market design we refer to views shared by our generation customers, such as Scottish Renewables.

Do you agree that we should continue to consider reforms that move away from marginal pricing? Please consider the relative advantages and drawbacks, and local institutional requirements, of distribution led approaches.

For specific questions in relation to proposed wholesale market design we refer to views shared by our generation customers, such as Scottish Renewables.

19) Do you agree that we should continue to consider amendments to the parameters of current market arrangements, including to dispatch, settlement and gate closure?

For specific questions in relation to proposed wholesale market design we refer to views shared by our generation customers, such as Scottish Renewables.

20) Are there any other changes to current wholesale market design and the Balancing Mechanism we should consider?

For specific questions in relation to proposed wholesale market design we refer to views shared by our generation customers, such as Scottish Renewables.

Chapter 6: Mass Low Carbon Power

21) Are we considering all the credible options for reform in the mass low carbon power chapter?
22) How could electricity markets better value the low carbon and wider system benefits of small-scale, distributed renewables?
23) Do you agree that we should continue to consider supplier obligations?
24) How would the supplier landscape need to change, if at all, to make a supplier obligation model effective at bringing forward low carbon investment?
25) How could the financing and delivery risks of a supplier obligation model be overcome?

26) Do you agree that we should continue to consider central contracts with payments based on output?
27) Are the benefits of increased market exposure under central contracts with payment based on output likely to outweigh the potential increase in financing cost?
28) Do you have any evidence on the relative balance between capital cost and likely balancing costs under different scenarios and support mechanisms?
29) Do you agree that we should continue to consider central contracts with payment decoupled from output?
30) How could a revenue cap be designed to ensure value for money whilst continuing to incentivise valuable behaviour?
31) How could deemed generation be calculated accurately, and opportunities for gaming be limited?

For views on specific market design options in this section, we refer to comments made by our generation customers in the north of Scotland. It is critical that any reform options in this space also consider impact and requirements for the GB transmission system to ensure resilient and robust security of supply.

Chapter 7: Flexibility

32) Are we considering all the credible options for reform in the flexibility chapter?

From a networks perspective, and by taking a whole system approach, large scale storage deployment will have a critical role in maintaining the fine balance between decarbonisation and grid system management as more intermittent renewable sources of electricity come on to the system and as more carbon heavy, traditional power stations come offline.

We believe that Transmission network owners and operators may benefit through greater deployment of this technology to further enhance system strength and operability. Whilst flexibility services will be critical in delivering our collective journey to Net Zero emissions, these currently tend to be scattered on the distribution network and therefore can be more difficult to manage operationally to provide system security compared to large scale options.

We believe that significant parts of current institutional framework, and organisations therein, are already delivering well for our future challenges. Transmission Owners (TOs) are already playing a crucial role in the achievement of GB's Net Zero targets, particularly in the north of Scotland, and DNOs have transitioned to a DSO with a certain amount of ease, although we do recognise the need for coordination and definition of roles and responsibilities.

SSEN Transmission play a key role in all facets of the transmission network, from future scenario planning through to connection processes, power system design or emergency restoration. A whole system approach is required to ensure that no unintended consequences occur across all DSO functions ensuring the provision of security of supply must be paramount. Communication and coordination are critical between all parties to ensure that the system as a whole remains resilient and flexible to support the changes to the use of the system at a subnational level, whilst maintaining high levels of resilience.

Flexibility at a subnational level alone will not be enough to deliver Net Zero. Whilst we acknowledge flexibility has an important role, however when and where flexibility is a proposed preferred solution, this must be actively assessed, not just as a cost assessment but also in the critical context of security of supply as well as the environmental impacts. Infrastructure development needs to be considered on an equal basis to ensure that short term economic benefits of flexibility can be balanced against long term environmental and socio-economic benefits of infrastructure development.

33) Can strong operational signals through reformed markets bring forward enough flexibility, or is additional support needed to de-risk investment to meet our 2035 commitment? Please consider if this differs between technology types.

We refer to views shared in the response of our generation customers in the north of Scotland for this section as we are not best placed to comment on revenue options for flexible technologies.

34) Do you agree we should continue to consider a revenue cap and floor for flexible assets? How might your answer change under different wholesale market options considered in chapter 5 or other options considered in this chapter?

We refer to views shared in the response of our generation customers in the north of Scotland for this section as we are not best placed to comment on revenue options for flexible technologies.

35) How could a revenue cap and floor be designed to ensure value for money? For example, how could a cap be designed to ensure assets are incentivised to operate flexibly and remain available if they reach their cap?

We refer to views shared in the response of our generation customers in the north of Scotland for this section as we are not best placed to comment on revenue options for flexible technologies.

36) Can a revenue (cap and) floor be designed to ensure effective competition between flexible technologies, including small scale flexible assets?

We refer to views shared in the response of our generation customers in the north of Scotland for this section as we are not best placed to comment on revenue options for flexible technologies.

37) Do you agree that we should continue to consider each of these options (an optimised Capacity Market, running flexibility-specific auctions, and introducing multipliers to the clearing price for particular flexible attributes) for reforming the Capacity Market?

We refer to views shared in the response of our generation customers in the north of Scotland for this section as we are not best placed to comment on revenue options for flexible technologies.

38) What characteristics of flexibility could be valued within a reformed Capacity Market with flexibility enhancements? How could these enhancements be designed to maximise the value of flexibility while avoiding unintended consequences?

We refer to views shared in the response of our generation customers in the north of Scotland for this section as we are not best placed to comment on revenue options for flexible technologies.

39) Do you agree that we should continue to consider a supplier obligation for flexibility?

We refer to views shared in the response of our generation customers in the north of Scotland for this section as we are not best placed to comment on revenue options for flexible technologies.

40) Should suppliers have a responsibility to bring forward flexibility in the long term and how might the supplier landscape need to change, if at all?

We refer to views shared in the response of our generation customers in the north of Scotland for this section as we are not best placed to comment on revenue options for flexible technologies.

41) **For the Clean Peak Standard in particular, how could multipliers be set to value the whole-system benefits of flexible technologies? And how would peak periods be set?**

We refer to views shared in the response of our generation customers in the north of Scotland for this section as we are not best placed to comment on revenue options for flexible technologies.

Chapter 8: Capacity Adequacy

42) **Are we considering all the credible options for reform in the capacity adequacy chapter?**
43) **Do you agree that we should continue to consider optimising the Capacity Market?**
44) **Which route for change – Separate Auctions, Multiple Clearing Prices, or another route we have not identified – do you feel would best meet our objectives and why?**
45) **Do you consider that an optimised Capacity Market alone will be enough for ensuring capacity adequacy in the future, or will additional measures be needed?**
46) **Are there any other major reforms we should consider to ensure that the flexibility Market meets our objectives?**
47) **Do you agree that we should continue to consider a strategic reserve?**
48) **What other options do you think would work best alongside a strategic reserve to meet flexibility and decarbonisation objectives?**
49) **Do you see any advantages of a strategic reserve under government ownership?**
50) **Do you agree that we should continue to consider centralised reliability options?**
51) **Are there any advantages centralised reliability options could offer over the existing GB Capacity Market? For example, cost effectiveness or security of supply benefits? Please evidence your answers as much as possible.**
52) **Which other options or market interventions do you consider would be needed alongside centralised reliability options, if any?**
53) **Do you agree that we should not continue to consider decentralised reliability options / obligations? Please explain your reasoning, whether you agree or disagree.**
54) **Are there any benefits from decentralised reliability option models that we could isolate and integrate into one of our three preferred options (Optimised Capacity Market, Strategic Reserve, Centralised Reliability Option)? If so, how do you envisage we could do this?**
55) **Do you agree that we should not continue to consider a capacity payment option? Please explain your reasoning, whether you agree or disagree.**
56) **Do you agree that we should not continue to consider a targeted capacity payment / targeted tender option? Please explain your reasoning, whether you agree or disagree.**
57) **Do you agree with our assessment of the cost effectiveness of a targeted capacity payment / targeted tender option, and the risk of overcompensation? If not, why not?**

For views on specific market design options in this section, we refer to comments made by our generation customers in the north of Scotland. It is critical that any reform options in the space also consider impact and requirements for the GB transmission system to ensure resilient and robust security of supply.

Chapter 9: Operability

58) Are we considering all the credible options for reform in the operability chapter?
59) Do you think that existing policies, including those set out in the ESO's Markets Roadmap, are sufficient to ensure operability of the electricity system that meets our Net Zero commitments, as well as being cost effective and reliable?
60) Do you support any of the measures outlined for enhancing existing policies? Please state your reasons.
61) To what extent do you think that existing and planned coordination activity between ESO and DNOs ensures optimal operability?
62) What is the scope, if any, for distribution level institutions to play a greater role in maintaining operability and facilitating markets than what is already planned, and how could this be taken forward?
63) Do you think that the CfD in its current form discourages provision of ancillary services from assets participating in the scheme? If so, how could this best be addressed?
64) Do you think it would be useful to modify the Capacity Market so that it requires or incentivises the provision of ancillary services? If so, how could this be achieved?
65) Do you think that co-optimisation would be effective in the UK under a central dispatch model?

We refer to views shared in the response of our generation customers on options for reform in this section. It is critical that any reform options in the space also consider impact and requirements for the GB transmission system to ensure resilient and robust security of supply, taking a whole system approach to solutions.

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Chapter 10: Options Across Multiple Market Elements

66) Do you agree that we should not continue to consider a payment on carbon avoided for mass low carbon power?
67) Do you agree that we should continue to consider a payment on carbon avoided subsidy for flexibility?
68) Could the Dutch Subsidy scheme be amended to send appropriate signals to both renewables and supply and demand side flexible assets?
69) Are there other advantages to the Dutch Subsidy scheme we have not identified?
70) Do you agree that we should continue to consider an Equivalent Firm Power auction?
71) How could the challenges identified with the Equivalent Firm Power Auction be overcome? Please provide supporting evidence.

For views in this section, we refer to comments made by our generation customers in the north of Scotland.

Thank you for providing the opportunity to share our views. Should you wish to discuss any of the points raised in our submission in further detail, please contact Kirstanne.Land@sse.com.

Appendix A: Reinforcement Vs Constraint Analysis

Please find a full copy of this report attached as part of the consultation response. Graphics and figures which refer to this appendix are directly from the attached report.