Sent by email to:
electricitydistributionstudy@nic.gov.uk

National Infrastructure Commission

10 May 2024

To whom it may concern,

Call for Evidence – How to ensure local distribution of electricity keeps pace with increasing demand

I am writing in response to the National Infrastructure Commission (NIC) Call for Evidence into local electricity distribution networks and the potential policy decisions that are required to make them fit for net zero. We welcome the additional focus provided by this study, reflecting the positive policy change following the report by Nick Winser setting out recommendations for accelerating the rollout of electricity transmission infrastructure.

Energy Networks Association (ENA) represents the companies that operate and maintain the gas and electricity networks in the UK and Ireland. Serving over 30 million customers, they are responsible for the transmission and distribution network of "wires and pipes" that keep our lights on, our homes warm and our businesses running. ENA welcome the opportunity to respond on behalf of its distribution network operator (DNO) and electricity transmission owner (TO) members.

Electricity networks must not become a blocker to the country's net zero and decarbonisation ambitions. It is vital the detail of the regulatory framework (and its application) evolves to deliver increasingly complex future requirements against a backdrop of industry wide supply chain and skills pressures. Whilst DNOs are currently making significant investments in electricity network infrastructure, it will be necessary to further advance the scale and pace of this investment in RIIO-ED3, whilst looking beyond the next price control period taking a longer-term view.

Now is not the time to unsettle the markets by introducing regulatory uncertainty. Fundamental changes to network regulation at this time could prove counter-productive to the delivery of net zero; but we recognise that regulatory evolution should:

- Improve **investability** to attract capital in global investment markets at this critical net zero juncture for each and every region;
- Ensure the continued **financeability** of electricity networks; given increased cost uncertainties and risk that will be experienced in the coming price control period(s);
- Ensure **efficient deliverability**, removing blockers where they exist in the current framework; and
- Balance **affordability** in terms of who/how/when it impacts customer bills.

There are 14 separate licensed electricity distribution network areas, which cover Great Britain. Each of these networks has been developed, designed and built over time to best serve the diverse needs of the range of domestic, business and industrial customers that are connected across GB's rural and urban landscapes.

Working in a regulatory framework that earned a reputation internationally for relatively consistent, light-touch, incentive and output-based regulation, the DNO sector has delivered for the country and their customers. That has included:

- Safe, reliable and efficient electricity networks:
    - Significant improvements in overall accident and incident rates, equating to a c.50% reduction in all injury incidents since 2015.
    - 99.9% network reliability.
    - Delivery against increased efficiency targets under the RIIO framework.
- Investing more than £22bn in the network infrastructure needed under the current RIIO-ED2 price control (2023-28).
- Consistently improved customer satisfaction levels since the inception of Ofgem's customer satisfaction and complaints incentives to a point where satisfaction ratings at or above 90% are seen as the norm in the industry.

In the increasingly high-profile area of connections, the DNOs have:

- Connected more customer projects in 2023/24 than in any prior year (4.2GW)
- Working collaboratively with each other, Ofgem and Government, delivered connections reforms that have:
    - Removed or accelerated nearly 5GW of queue projects through more active queue management;
    - Accelerated c.1.8GW of generation and storage projects by an average of 5 years through transmission & distribution reforms (the application of technical limits within which the DNOs can manage the impact at the interface with the transmission network); and
    - Released nearly 15GW of capacity for storage and demand projects through technical reforms in the way network impact is assessed.

In addition, in the transition from DNO to DSO, distribution system operators (DSOs) are actively contributing to the development of a world leading local flexibility market in GB, delivering efficiency savings for customers.

The grid is undergoing its biggest ever upgrade and electricity distribution networks sit at the heart of enabling decarbonisation. As such, we recognise the need for sufficient capacity on our electricity networks to deliver net zero. Our networks must also be resilient to the changing climate, whilst ensuring customers continue to receive a safe and reliable service. The DNOs are already delivering significant programmes of work to achieve this and to ensure their networks are ready to meet the changing needs of their customers.

Government and the NIC are right to acknowledge that different recommendations are required on the distribution network to solve similar fundamental problems it shares with transmission. "Large and lumpy" transmission versus "little and often", locally driven, distribution investment is a fundamental reason why different solutions are needed. Further:

- An immediate challenge for distribution customer connections is transmission constraints. DNOs and TOs are working with the industry to help find solutions to this.
- Transmission requires more complicated planning and investment in isolation, but distribution is more complex and diverse, therefore so are the problems and solutions as a package. For example:
    - Meshed networks.
    - Distribution has greater multi-sector/vector considerations, e.g. electricity, gas and water (possibly broadband) assets may be laid in the same trenches, and has more touchpoints with other sectors such as rail.
    - Competition in connections (with independent distribution network operators (IDNOs) and independent connection providers (ICPs)) on distribution networks is mature and has been tested. We are supportive of competition, where proven to deliver benefits for customers.
- Whilst transmission projects are individually of a higher value, they collectively require significantly less workforce commitment than is required for the high volume of distribution projects, particularly at the low voltage level. Distribution projects also directly impact on a significantly larger number of customers/stakeholders.
- Transmission is grouped more strategically and investment is easier to predict.
- Distribution can alleviate transmission issues e.g. controlling export onto the transmission network.

Summary

The NIC's call for evidence raises some very important questions on issues that, in practice, are often complex and multi-faceted. As ever, that creates a range of views on the best way to address the detailed implementation. But it has become clear to us in preparing this response that there is a high degree of consensus among our member companies on the key points. Our response seeks to emphasise those. In short, these are:

- We are supportive of the RIIO model which has proven beneficial for customers to date. The importance of getting the framework detail/and its application right will mean evolving to deliver future requirements, including net zero and decarbonisation.
- The RIIO-ED3 framework must be flexible to the need to ensure the right pace of change, reflective of customer and regional differences.
- Decisions for investment in RIIO-ED3 must be taken in the context of the long-term pathway to 2050 and must consider some important benefits and trade-offs.
    - Net zero delivery represents a significant economic growth opportunity, creating jobs with the requirement for growth.
    - The need to achieve net zero and ensuring the protection of current and future customer interests needs to be balanced.
- We believe in a principle-based approach that is generally based upon "touch the network once", with a focus on planning towards the electricity network of 2050.
- We recognise that non-network build solutions, such as flexibility, will also play a key role in meeting the demands of a net zero system. Through local flexibility services, DSOs are already unlocking additional capacity and supporting the connection of low-carbon technologies.
- Local Authorities (LAs) have a vital role in the energy transition, with Regional Energy Strategic Planners (RESPs) supporting and aggregating/consolidating different stakeholder views.

- Funding for network innovation should be strengthened within the regulatory framework. It will play a significant role in unlocking future value in the transition to net zero and ensuring affordability for customers.
- Data & digitalisation also have an important role in the delivery of net zero. Through advancements we will further increase levels of network visibility and support smarter network solutions.
- We believe the current statutory framework for electricity land rights and consents needs modernising to enable net zero delivery.
- The connection issues faced at transmission are different to those at distribution.
- DNOs are collaborating through the ENA to implement reforms that are already materially benefiting connections customers; however continued reform and collaboration across DNOs, TOs, the National Energy System Operator (NESO), Ofgem and DESNZ will be critical.
- We are supportive of the Government's Connection Action Plan and are committed to continued collaboration between the Government, Ofgem, NESO and electricity networks.
- Simply connecting the whole queue is not what Britain needs (the current queue includes 659GW of generation and storage projects – 2.4x the capacity required for our most ambitious 2050 ("Leading the Way") scenario). Policymakers (Ofgem and DESNZ) should also consider how to prioritise access to the network to enable the most efficient and effective network for all customers and consumers.
- DNOs currently build and maintain resilient/reliable networks and will continue to do so in the face of evolving threats and challenges, including:
    - Climate change
    - Cyber security
    - Peoples' greater reliance on electricity

POLICY, REGULATION AND GOVERNANCE

As previously commented upon, it is vital the detail of the regulatory framework (and its application) evolves to deliver increasingly complex future requirements against a backdrop of industry wide supply chain and skills pressures. In this context a fresh look at the framework is required to ensure:

- It is reflective of the heightened risks that will be faced by DNOs in RIIO-ED3, including:
    - the scale and pace of investment programmes;
    - competing supply chains and workforce availability; and
    - increasing threats to the resilience and reliability of the distribution networks from climate change and cyber-attacks.
- There is an appropriate balance between foundational ex-ante allowances which should be the primary basis of the funding of electricity networks, and Uncertainty Mechanisms (UMs) providing additional allowances as required in RIIO-ED3 which will be vital.
- Incentives are reprioritised for RIIO-ED3 and designed to reward desired behaviours. Incentives were a core aspect of the RIIO framework when it was first introduced but have been diluted in RIIO-ED2.
- Incentives should provide clearer and stronger motivation for networks to (for example) encourage further innovation in reducing costs and increase efficiencies of investments, and to further strive to improve customer service (e.g. in connections) and resilience levels. This will require a combination of stretching but realistic incentive targets and the use of an appropriate balance of opportunity to earn rewards and less of a focus on simply avoiding penalties.

These aspects will be even more relevant in RIIO-ED3 where the scale of change in investment needed will require increased focus on how programmes are delivered, together with potential synergistic benefits (e.g. with non-load related investment) to deliver further customer benefits.

For RIIO-ED3, we believe in a principle-based approach that generally looks to “touch the network once”, with a focus on planning for the electricity network of 2050. That does not rule out alternative approaches, where they are shown to have greater benefits, e.g. the phased development and release of capacity for motorway service areas and electric vehicle charge points. Adoption of this approach will enable the networks, and relevant stakeholders, to better achieve benefits around establishing stability of supply chains, creating jobs for the present and future and increased efficiencies for customers as networks plan their investments over the longer-term.

Readiness for net zero also requires adaption of the distribution networks for the changing climate. Whilst our electricity networks are currently amongst the most reliable in the world, recent weather-related events have highlighted the need for our networks to be adapted to meet increased incidence of high and gusting winds, flooding, and threat from fire. Investment in our networks needs to be planned with climate change resilience in mind. In general, the investment needed to enable net zero will bring synergistic benefits to the resilience of the network, but this alone will not deliver the resilience of the network to a changing climate.

We believe the RESPs can play an enabling role in regional energy planning empowering local authorities and Devolved Governments. They present a key opportunity to add value by increasing cross-vector coordination. However, we are still in the very early stages of RESP development, and most of the detail still needs to be developed. Network companies will continue to constructively engage with Ofgem and NESO on RESP development to maximise their potential. Interactions with RIIO-ED3 need to be better understood, as well as any potential interim arrangements, learning from RIIO-ED2.

ENA has engaged Regen to undertake a project to study the potential complementary roles and responsibilities between the DNOs and a future RESP function. We would be happy to share a copy of this report with NIC as soon as it is complete.

TECHNOLOGY AND SOLUTIONS

Non-network build solutions, such as flexibility, will also play a key role in meeting the demands of a net zero system. Through local flexibility services, DSOs are already unlocking additional capacity and supporting the connection of low-carbon technologies such as wind, solar, storage, EVs and heat pumps.

The scale, timing, and nature of activities and approach to the network build programme will differ between transmission and distribution networks, reflecting the more localised nature of distribution investment. There will also be regional differences to meet the specific requirements of local networks and the needs of the customers connected/connecting to them.

ENA’s Open Networks programme has been at the forefront of the developing flexibility market. Through this, DSOs tendered a record 5.5GW of capacity on local flexibility markets during the financial year 2023-24, with 2.5GW contracted, making GB the largest flexibility market in the world.

We recognise further work is needed to deliver maximum benefits for our customers. To this end, the Open Networks programme is focused on bringing more participants into the flexibility market, creating a uniform customer experience and developing common standards. In addition to this, the establishment of a DSO

Incentive in RIIO-ED2 is enabling Ofgem and industry to better track the benefits being unlocked by DSO activities.

The DSO will have a key role in determining when and how best to first utilise flexibility/non-network solutions before moving to traditional network build solutions, increasing efficiencies and delivering faster connections ahead of reinforcements.

CONNECTING TO THE DISTRIBUTION NETWORK

DNOs are working collaboratively to resolve any barriers and delays for connections to distribution networks. For the majority of customers however the distribution network itself is not the blocker. The majority (172 of 198) of Grid Supply Points (GSPs) are constrained as a result of transmission constraints and distribution customers face considerable delays as a result. TOs are also working collaboratively to ease the blockage.

Whilst constraints on the distribution network can be resolved in relatively short timescales, and over 57GW of customer projects can connect to the distribution network without undue network delay, this only represents c. 35% of the queue. The remaining 65% of the distribution queue, over 108GW of customer projects, are dependent on or being assessed for transmission reinforcement. Transmission constraints also can take considerably longer to resolve in comparison.

DNOs are focused on this issue, working across industry initiatives such as: the Ofgem and DESNZ Connection Action Plan, Networks' fair and faster connections plan outlined in the ENA's Rising to Britain's Net Zero Challenge, and the NESO's tactical and strategic connections reform initiatives. In particular DNOs are supporting work to improve queue management and queue entry requirements, as well as resolving issues associated with transmission/distribution technical limits and introducing changes to battery storage assumptions.

Constructive and rapid collaboration across networks, Ofgem, and DESNZ will continue to be critical as reforms are identified, designed, approved, and implemented to improve connections outcomes. Additional focus - across Networks, Ofgem and DESNZ - is required on how entry requirements can be raised for customers joining the queue to increase the quality of projects contracting for network capacity.

Finally, simply connecting the whole queue is not what Britain needs; policymakers (Ofgem and DESNZ) should also consider how to prioritise access to the network to enable the most efficient and effective network for all customers and consumers.

Enabling Network Delivery

Another significant issue is associated with the current statutory framework for electricity land rights and consents. This framework is outdated and must be modernised to enable the pace of delivery required for the electricity network infrastructure to achieve the Government's net zero/decarbonisation targets and improve timescales for providing connections to the distribution network.

Our detailed response references work by ENA and our 'Nine-Point Plan', detailing those areas of the current system that require procedural and systemic reform. This plan is backed-up by case studies that evidence the challenges currently facing the networks. As the scale and pace of low carbon technology connections grow, particularly at low voltage levels, so will the scale and need for rapid delivery of the associated network infrastructure. The successful delivery of this work will be seriously jeopardised without reform. Our Nine-Point

Plan was developed in response to the Government Call for Evidence on Land Rights and Consents for Electricity Network Infrastructure (published in August 2022). Little progress has been made since. Whilst we are expecting DESNZ to publish its response to the Call for Evidence soon, greater urgency is needed.

In closing, ENA welcomes this opportunity to contribute to the NIC review of local distribution networks. We would be very much like to meet with you to discuss the issues raised and proposals offered in this response. Please do not hesitate to contact Paul McGimpsey, ENA Director Markets & Regulation (paul.mcgimpsey@energynetworks.org) to arrange.

Your faithfully,

Lawrence Slade
Chief Executive

ENA Response to Call for Evidence Questions

POLICY, REGULATION AND GOVERNANCE

1. Does the current RIIO-ED2 price control do enough to enable required investment in additional capacity? What changes should be considered for the next price control period (RIIO-ED3) to ensure that required investment is identified and enabled?

One year into RIIO-ED2, it is too early to say whether it is doing enough to enable the investment needed in the period and more generally delivering upon the needs of customers, net zero and decarbonisation. RIIO-ED2 funded baseline allowances to meet the lowest decarbonisation pathway, with over 30 Uncertainty Mechanisms (UMs) in-play to facilitate DNOs accessing additional investment either made or forecast to be made and in the period. Central to RIIO-ED2 delivering investment in, and driven by needs in, the period is:

- Ofgem ensuring there is sufficient flexibility in its application, catering for DNOs that are experiencing different levels of load growth as the energy transition is unfolding at different speeds across GB regions;
- efficient, effective and timely decision-making (given the pace of transition) to ensure there are no delays to critical investment decisions; and
- mechanisms that allow DNOs to effectively manage growing industry wide constraints, most notably the supply chain capacity challenges.

Looking ahead to RIIO-ED3
The RIIO framework will need to evolve to respond to both experience and to lessons learnt in RIIO-ED2, as well as to wider energy and economic policy changes. Longer-term decision-making is essential to improve financability, investability and deliverability of net zero and decarbonisation policies.

To achieve this, the balance between ex-ante allowances and UMs in RIIO-ED3 should be reviewed, with:

- Ex-ante allowances forming the primary foundations of funding DNO business plans (supported by needs cases for investments – and supported by robust stakeholder engagement/local plans).
- UMs being used for investments for which there is more uncertainty. It will, however, be essential that Ofgem can/will administer UMs in the timescales that are needed, ensuring they can work in a way that considers the network of the future. Consideration should be given to the adoption of automatic UMs, where possible, to reduce administrative burden and to respond quickly to changing external factors.

Key areas upon which clarity in the RIIO-ED3 frameworks will be needed include:

- How and who will determine the investment needs case? An understanding of the roles of the RESPs in setting RIIO-ED3, and longer-term, will be key.
- The future energy scenario we are building the network to accommodate. We support a common scenario for electricity distribution that is cognisant of scenarios assumed for other sectors and which reflects sector specific issues and regional characteristics in how these will affect local networks.
- There being sufficient flexibility in the framework to build the network of the future, under any energy scenario.

Whilst significant progress has been made in the upgrade and expansion of our networks thus far, the step-change in the scale of investment and pace of delivery in RIIO-ED3 will be significant. To deliver this, the DNOs must be able to attract the investment that will be required to deliver significant new work programmes, and funding must be accessible when it is needed, either via upfront ex-ante funding or effective UMs.

The consequences for customers and society of getting RIIO-ED3 financing decisions wrong would be very significant. Customers and society have never been more reliant on the provision of safe and secure electricity supplies. If the allowed rate of return is insufficient, then there is a clear risk that companies may be unable to attract the capital needed to finance the investment required or retain existing capital. If DNOs cannot attract and retain the required capital, then this will immediately hamper the ability of any company to deliver what customers and society require of them.

DNOs will face heightened risks in RIIO-ED3 relative to RIIO-ED2. These risks will be reflected in investors' perception of the risks associated with investing in the electricity networks and therefore in the financing costs that DNOs will bear. The scale and pace of the investment programmes in RIIO-ED3 in support of the changes needed to achieve net zero will be unprecedented. The sheer number, complexity and scale of projects and programmes, and the associated series of delivery, planning, consenting and reputational challenges will be at a scale never experienced before.

There will also be increasing threats to the resilience and reliability of the distribution networks arising from the effects of climate change and increasing threats from cyber security. All these factors will further increase financing costs for RIIO-3 beyond the increases that will arise due to changes in the macroeconomic environment. The concept of investability in the RIIO-ED3 framework will therefore be vitally important. Investability assessment must feature heavily in Ofgem's design of the RIIO-ED3 financial framework.

DNOs (along with other utilities) will face increased risk due to competing supply chains and workforce availability. Clarity and certainty that DNOs will be funded to deliver the investment needed for net zero and support securing the supply chain and workforce is needed.

Incentive regulation central to any approach

The current regulatory regime, with its focus on ex-ante incentive regulation, has delivered, and continues to deliver, transformational change in GB networks that customers have benefited from. Price control design has evolved to address changing needs, and regulators from around the world have looked and continue to look to GB as an example of best practice regulation.

It is important the regulatory framework continues to deliver for customers. Different sectors face specific challenges and will need to evolve in different ways and to differing extents to continue to meet customers' needs. In recognition, some aspects of the current approach to regulating networks will need to evolve in response to the change in scale of some activities, to the change in market conditions and to remove acknowledged shortcomings of the current regulatory approach. Incentive based regulation has to remain central to any approach.

A fresh look at the RIIO-ED3 framework will be required to ensure incentives are designed to reward desired behaviours, which was a core aspect of the RIIO framework when it was first introduced and has been diluted in RIIO-ED2. There should be reprioritisation of incentives in RIIO-ED3, providing clearer incentives for DNOs to, for example, encourage further innovation in reducing costs and increase efficiencies of investments, and to further strive to improve customer service (e.g. in connections) and resilience levels. This will require a

combination of stretching but realistic incentive targets and the use of an appropriate balance of opportunity to earn rewards and less of a focus on simply avoiding penalties.

2. Does current planning policy impede the deployment of distribution network upgrades? If so, what solutions could alleviate this? Please provide examples.

The current statutory regime for electricity land rights and consents is inadequate to enable the delivery of the ambitious net zero targets. In particular, the current system is too costly, protracted, and does not provide time certainty for both electricity customers and electricity network licence holders in respect of the delivery of new, and retention of existing, apparatus.

The challenge to deliver an electricity network that is equipped to meet the Government's objectives is a national priority, requiring immediate action. Underpinning this challenge is the need for both distribution and transmission network operators to secure land rights and consents for both new and existing electricity apparatus.

As we transition to a decentralised and decarbonised energy system, electricity networks must play a critical role in providing timely new connections and upgrades to enable the uptake of low carbon technology in existing and new homes, commercial and industrial sites, and new power generation.

The Legislative Framework

When referring to 'planning policy' related barriers to the deployment of distribution network upgrades it should be recognised that securing necessary land rights, including access rights, is equally as important as securing necessary planning consents and permissions. Both are needed to build, upgrade and maintain networks infrastructure.

DNOs currently need to gain:

- **Consent** to build and upgrade electricity network assets (commonly referred to as planning permissions); and
- **Land Rights** which provide the ability to access land in order to install and maintain such assets.

Setting a legislative framework that best facilitates quicker more efficient delivery of new, upgraded and refurbished electricity infrastructure will require coherent change across all voltage levels i.e. transmission and distribution in England & Wales and Scotland.

Under the Planning Act 2008 National Significant Infrastructure Projects (NSIPs) and associated Development Consent Orders (DCOs) apply to electricity infrastructure projects on:

- New build 132kV Overhead Line (OHL) projects at/exceeding 2km
- All new build OHL projects at voltages over 132kV

For all other new build and refurbishing/upgrading of existing electricity infrastructure of all voltages i.e. 132kV Overhead Line (OHL) projects under 2km, 66kV, 33kV, 11kV, 6.6kV, LV, the following are relevant:

- Electricity Act 1989 Sch. 3 & 4 (Compulsory Purchase Order & Necessary Wayleave)
- Electricity Act 1989 Section 37 (OHL planning permission and permitted development)

- Town & Country Planning Act and General Permitted Development Order (planning permission and permitted development)
- The Overhead Lines (Exemption) (England & Wales) Regulations 2009 and Scotland 2013

Table 1 in the Annex shows the land rights and consents required by networks, (excluding those covered by Planning Act 2008). Note that corresponding subordinate legislation in Scotland also applies.

An outdated legislative framework not 'fit for purpose'
Table 2 in the Annex provides a brief overview of some of the weaknesses across some areas of the current framework.

Need to modernise the legislative framework
It is essential that new policy measures for land rights and consents address the weaknesses set out in order to facilitate efficient and timely delivery of investment in electricity distribution networks, by replacing, where appropriate, the current framework that is now outdated and not 'fit for purpose'. The current framework results in unnecessary delays and additional costs that are borne by households and businesses in their energy bills and represents a major barrier and risk to Government's wider strategy for delivering investment, clean growth and meeting customer needs. The weaknesses in the current statutory framework for land rights and consents will need to be addressed if these risks are to be mitigated.

We welcome the Government's Transmission Acceleration Action Plan (TAAP) that will halve the overall build timeline for electricity transmission network infrastructure. Crucially the TAAP recognises the need to review the current statutory framework and associated processes for securing and renegotiating necessary land rights and consents, particularly at lower voltages (distribution), and commits to publishing next steps and agreed policy measures in Spring 2024.

To take forward the policy proposals the Government has established the 'Land Rights and Wayleaves Working Group' that is chaired by DESNZ and comprised of representatives from other relevant government departments, electricity networks and landowner organisations. The working group will report to Ministers at end 2024.

To inform this work ENA has undertaken extensive consultation with its members and prepared a **'Nine-Point Plan'**, detailing those areas of the current system that require procedural and systemic reform. This plan was developed in response to the Government Call for Evidence on Land Rights and Consents for Electricity Network Infrastructure (published in August 2022). The majority of the reforms we are proposing can be delivered at pace and should be taken forward with urgency. The detailed solutions to these land rights and consenting related barriers (including the Nine-Point Plan itself) are set out in ENA Report '*Our Common Sense Plan for Planning': Land Rights and Consents for electricity infrastructure, proposals for reform*'.

In proposing these changes, we fully recognise the importance of balancing the need to access land to build new and maintain existing electricity infrastructure with the rights of landowners. Consequently, as part of the Nine-Point Plan we are committed to a Code of Practice that would set out the requirements and responsibilities of network operators and landowners in conducting negotiations for the acquisition of new and retention of existing consents as well as ongoing access, operation and maintenance of electrical apparatus situated on private land. The Code of Practice would provide for a standardisation of approach in third party matters, for example providing an appropriate route for Alternative Dispute Resolution (ADR) to seek and avoid the need for referral to the Necessary Wayleave process. This can be supplemented with appropriate safeguards, including sanctions on networks where relevant.

We would further welcome focus on:

- The increasing delays to Section 37 approval. There is a need to ensure coordination of network and spatial planning, driving change in the planning system and timeliness of approvals.
- On connections: Alignment of spatial planning decisions into the connections process, through either strategic engagement between local authority planners and DNO planners, or consideration of spatial planning progress into a gated connections process/milestones.

Need for urgency

The Government's consultation on land rights and wayleaves was issued in Summer 2022 and whilst we welcome the clear acknowledgement by Government that there are land rights and consenting issues that must be addressed and work is being taken forward, it should not be delayed until finalisation of the NIC study in early 2025. We therefore propose this is an early recommendation from commissioners as part of an interim update.

3. To what extent can a move to more strategic planning of the network at transmission level be replicated for the distribution network? What would be the benefits and costs of doing so? In answering this question, please consider the interaction with forthcoming changes to strategic energy planning, such as the introduction of Regional Energy Strategic Planners.

We support more strategic planning and investment on the distribution network (e.g. review whether upsizing when replacing extra bays in substations when intervening to accommodate future growth is required, consideration of increased off gas grid investments, and the potential for installation of 3-phase cable rather than single phase) and believe in an approach that is generally based upon the principle of "touch the network once", with a focus on planning towards the electricity network of 2050. That is not to say that this approach should always be followed where it does not promote more efficient network development or better delivers customer needs. For example, the delivery of phased network development and release of capacity for motorway service areas and electric vehicle charge points.

This principle should equally apply to asset replacement where assets will be replaced with ones of larger capacity to maximise the life of those new assets. Ultimately, the key requirement for DNOs is the ability to consider investment needed to meet future forecast load-driven need.

Strategic planning and investment are important for the efficient delivery of regional needs – synergistic benefits can be realised, including impacts on longer-term resourcing plans and supply chain certainty. RESP should support this through incorporation of local plans such as local area energy plans (LAEPs) as inputs in the definition stage of strategic requirements – and where such regional requirements should be well justified based on robust examination. DNOs must be able to consider RESP strategic requirements with holistic planning to ensure continuation of compliance with all licence/statutory obligations.

Although some principles are transferable, most of the details of the Accelerated Strategic Investment (ASTI), Strategic Spatial Energy Plan (SSEP) and Centralised Strategic Network Plan (CSNP) approach for the strategic development of the transmission network are not directly applicable because distribution network development comprises greater quantities of lower value interventions, compared to fewer high value

interventions at transmission. Also, distribution network developments take less time to plan and implement compared to transmission projects.

DNOs are supportive of the introduction of RESPs and see this change as a significant opportunity to support customer decarbonisation and cross-vector coordination. The introduction of new strategic planning processes at transmission level over recent years has resulted in much greater clarity of the future needs that those networks need to serve. This greater clarity has, in turn, allowed transmission networks to focus on efficient delivery to meet those needs with positive impacts on longer-term resourcing plans and supply chain certainty.

Key considerations of the role of RESPs include the need to:

- Avoid duplication.
- Be complementary to existing obligations/licence obligations.
- Be cognisant of local and devolved net zero targets and ambitions.

We recognise that DNOs have an important role in the data and digitalisation necessary to facilitate the role of RESPs.

At the highest level, the RESPs should consider aspects that require whole energy system and cross-vector thinking to achieve maximum value add for customers. RESPs should engage with stakeholders to develop whole system regional energy plans that reflect regional, local and Devolved Government priorities. This key strategic output of each RESP would be developed, taking into account national targets and stakeholder inputs. Where appropriate, the RESPs' role could include supporting Local Authorities and stakeholders to grow their capability to develop LAEPs which will be a key input to the RESP whole system plan.

DNOs will need to develop their overarching network investment plans holistically in order to discharge their accountabilities including in respect of developing and maintaining an efficient, co-ordinated and economical system of electricity distribution and making connections between a distribution system and premises when required to do so. This requires that the translation of RESPs' whole system regional energy plans into electricity network needs must remain the accountability of DNOs. This also means that the status of the RESPs' input to DNOs' plans and associated governance arrangements surrounding the new processes will need to be different to those implemented for transmission. In particular, processes must be in place to enable DNOs to make evidence-based adjustments to the RESP output to support efficient network investment or to ensure that DNOs can discharge their accountabilities. This must include, for example, allowing DNOs to evolve their plans outside of the RESP "planning cycle" to respond to later information and DNOs continuing to be able to engage with local stakeholders about local electricity network needs.

NESO is a new organisation that will be tasked with delivering complex, strategic activities the delivery of which will often require key, scarce knowledge and skills. We must avoid overloading an organisation that will still be forming in its role and allow NESO to retain focus on its strategic objective. This is likely to require the responsibilities and activities of NESO to scale up over time. This should be managed in a clear and transparent manner so that accountability for key tasks is clear to all parties at this crucial period in the transition to net zero. We must ensure clear distinction between the respective roles of Government, Ofgem, NESO and networks at all times throughout the transition to new working arrangements.

The next regulatory period for DNOs, RIIO-ED3, will be a crucial period for the transition to net zero and to the decarbonisation of energy supply. The planning process for the RIIO-ED3 period will begin in earnest soon. We must be realistic about what role NESO/ RESPs will be able to perform in inputting to these plans. RESP implementation should not be rushed for RIIO-ED3, rather its role for RIIO-ED3 should be shaped based on what capability will have been established at the relevant time and, if necessary, interim models explored to deliver a RIIO-ED3 timeline that is fit for purpose.

4. To what extent will making the distribution network fit for net zero also help ensure that it is adapted to a changing climate? Are there any potential conflicts between meeting additional demand and adaptation, or any additional steps required to ensure adaptation is effective?

Making the distribution network fit for net zero energy demands will not on its own adapt the network for a changing climate. The process for climate adaption should also be considered for upgrades to the existing network, making them more resilient to the challenges of storms, and be taken into account in longer-term planning.

Network investment should be planned with climate change resilience in mind, generally requiring a multi-driver 'touch it once' approach towards planning the electricity network of 2050. This approach will ensure synergies are made between the different investment categories, enabling DNOs to most efficiently realise climate change benefits in investments for decarbonisation, asset replacement and adaption more generally. As we move towards net zero, customers' behaviours and the impact of an increased dependency on electricity need to be understood. For example, traditionally networks have experienced higher loadings in winter and lower loadings in summer – however, this will be challenged through the move to net zero.

Electricity networks work collaboratively on climate resilience and adaptation. DNOs are currently factoring in additional risks into their investment plans to protect network assets, noting shifts in storm patterns and increased environmental impacts throughout the year, e.g. flooding, wildfires, etc. Ongoing development of investment plans is required as new or emerging threats are identified. Consequently, investment needs may not be sufficiently reflected in business plans and as a result not reflected in price control cost allowances.

A good example of this is Storm Arwen, which coincided with the timing of DNOs submitting their RIIO-ED2 business plans. Cost allowances, as a result, did not include the activities associated with delivering the improvements identified as being necessary until after the event. The Storm Arwen reopener enabled opportunities for additional funding, over and above those already included in business plans, for improvements relating to storm response.

Effective adaptation of the network will therefore require an appropriate balance between ex-ante funding for load related expenditure and UMs. We support Ofgem's proposed long term approach to climate resilience however further development of the RIIO framework will be needed to enable fast-tracking of decision-making of UMs of this type.

5. Are there any other ways in which policy, regulation and governance could be improved to deliver a resilient electricity distribution network fit for net zero?

Improvements to regulatory framework

Fundamental changes to network regulation are unnecessary and could prove counter-productive to the delivery of net zero. Instead we believe evolution of the RIIO framework to be appropriate, taking learnings from RIIO-ED1 and the first year of RIIO-ED2. In designing this, key questions will include:

- How and who will determine the investment needs case for business plans in RIIO-ED3?
- An improved understanding of the role of RESPs.
- What future energy scenario(s) should DNOs be planning, designing and building the distribution networks of the future to accommodate?
    - Experience from the RIIO-ED2 process, gives strong credence to there being a single common planning scenario that all DNOs utilise to develop their RIIO-ED3 plans.
    - We support a common scenario for electricity distribution that is cognisant of scenarios assumed for other sectors and which reflects sector specific issues and regional characteristics in how these will affect local networks.

We recognise there must be sufficient flexibility in the framework to build the network of the future. The appropriate use of UMs, which can be applied to investments for which there is less certainty, will be central to this.

It will be essential however that Ofgem can/will administer these UMs in timescales that ensure there are no delays in DNOs acting upon stakeholder/other requirements, e.g. in response to storms, cyber threats, etc. In this regard framework developments are necessary to improve efficiencies in current processes, introduce more automatic UMs which reduce administrative burden and improve the ability for all parties to respond quickly to changing external factors.

Incentives

Whilst incentives formed a core aspect of the RIIO framework when it was first introduced for RIIO-ED1 in 2015, they now play a less prominent role in RIIO-ED2. Incentives should be reprioritised in RIIO-ED3 where their inclusion will better facilitate the delivery of a resilient electricity distribution network fit for net zero and the needs of customers and stakeholders.

Incentives for more resilient networks associated with customer outputs should be recognised (e.g. Interruptions Incentive Scheme (IIS) and Network Asset Risk Metric (NARM) incentive), however changes will be needed to recognise the value customers place on electricity as well as the challenges of climate change, so that further increases in network resilience and customer outcomes can be delivered in future.

Public awareness

The investment for net zero and meeting resilience requirements will deliver a high-quality standard of service to customers. Greater public awareness of the cost, pace of change and choices associated with progressing net zero and ensuring the network is resilient is needed, including the resultant impact on customer bills. Policy options surrounding the future proofing of connections work should also be considered.

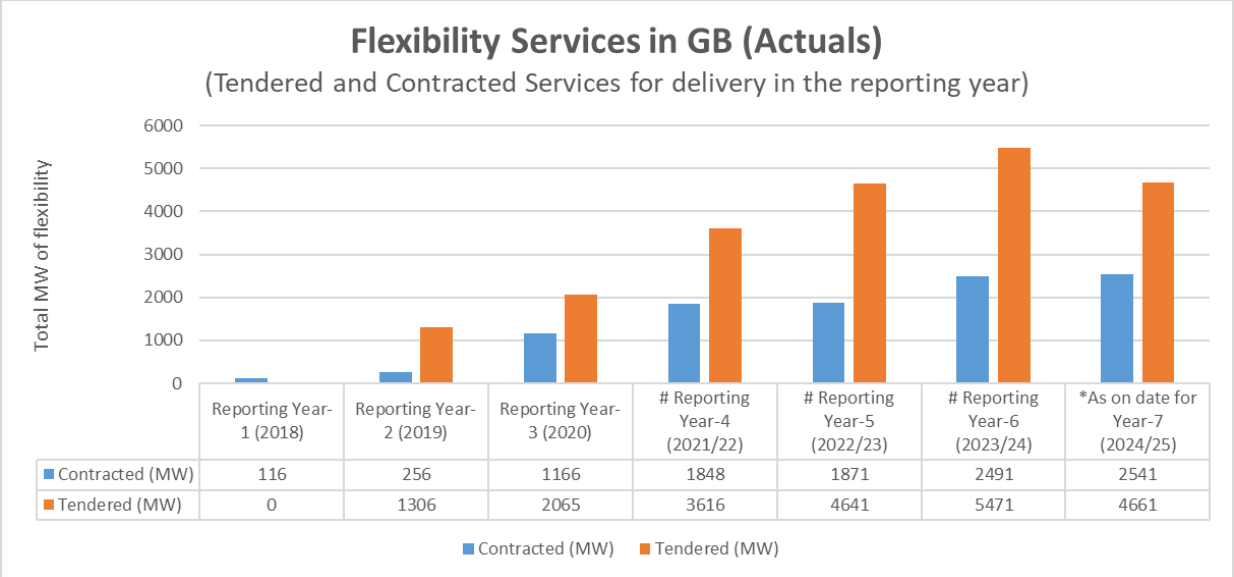
TECHNOLOGIES AND SOLUTIONS

6. What solutions could be used to provide additional capacity without new network investment? Does the current price control do enough to encourage non-network solutions? Please provide evidence of their real world or potential impact on avoided network investment.

Technology, including smart grids and network digitisation, have a significant role to play. The key is to use the existing network most effectively, making use of flexibility to release capacity and optimise, and where it is appropriate to reinforce, adopting the "touch the network once" principled approach, to meet the needs of current and future customers and the transition to net zero.

Through effective monitoring of the network DNOs are better able to predict where next to reinforce to enable the transition to, and delivery of, net zero. This can be achieved using a combination of LV monitoring, smart meter data and wider data/ analytics to enhance forecasts. Flexibility/non-network solutions may be used in the interim to facilitate more immediate connection requirements, providing a cost-efficient approach to releasing capacity without risking stranded assets, whilst allowing the value of flexibility contracts to be directed to the end customer.

ENA's Open Networks programme has been at the forefront of the developing flexibility market. Through this, DSOs tendered a record 5.5GW of capacity on local flexibility markets during financial year 2023-24, with 2.5GW contracted, making GB the largest flexibility market in the world. The growth of the distribution flexibility market in GB is shown in the chart below.



	Reporting Year-1 (2018)	Reporting Year-2 (2019)	Reporting Year-3 (2020)	# Reporting Year-4 (2021/22)	# Reporting Year-5 (2022/23)	# Reporting Year-6 (2023/24)	*As on date for Year-7 (2024/25)
Contracted (MW)	116	256	1166	1848	1871	2491	2541
Tendered (MW)	0	1306	2065	3616	4641	5471	4661

It is important that we do not view this as an "either/or" between network and non-network solutions. We need both pragmatic and targeted investment in infrastructure and an acceleration in deployment of flexible solutions if we are to reach net zero targets. We are going to need every tool in the toolbox, such as flexibility, innovation

and digitalisation, however, this will not remove the need for increased investment in the network to build more capacity where it is truly needed.

Whilst the regulatory framework facilitates this, there is a need to place stronger incentives on the networks to deliver efficiently. Well-calibrated incentives will provide focus on the key things that matter most to customers, e.g. reliability and customer service and are central to the leading RIIO regulatory model.

The role of DSO will be at the heart of net zero, considering and delivering alternatives to traditional network reinforcement where optimal to do so, reflecting regional characteristics such as availability and requirements of customers. There is significant potential for distributed assets (such as EV batteries as network storage) and network integrators to have a role in this regard, however stability is needed to facilitate long-term commitment, allowing the markets to value the need for flexibilities services; and where increased competition should drive down the cost to customers.

The operating model for DSO has multiple options and the best model is that which delivers most customer value for the region and its customers as well as the roles of others such as NESO, RESP and LAs with LAEPs.

The markets and regulation should continue to provide the opportunity for DNOs to provide flexibility services to the NESO and other network operators (e.g.) via Customer Load Active System Services (CLASS) and the Fast Reserve Market (and upcoming Quick Reserve Market). However, clarity is needed on enduring regulatory treatment of costs and revenue for such services, which should then translate into lower customer costs.

DNOs should be able to provide system services to the NESO and to other network operators in order to drive whole system efficiencies - to this end there needs to be enduring arrangements that recognise how costs and value are assigned to different parties alongside incentives to drive the right behaviour. Any ambiguity should be cleared up well before the submission of RIIO-ED3 business plans so that DNOs can ensure they are able to invest accordingly.

7. What role could digitalisation and data play in supporting efficient management of existing capacity and targeting of investment in new capacity? Are there examples of where the benefits have been realised through trials or examples used in other markets?

Data and technology will play a central role in net zero delivery. Achieving high levels of network visibility through a combination of LV monitoring, smart meter data and digital tools will support delivery of local plans and ambitions.

The following are examples of where data and technology is being used to manage the network:

- To accurately monitor and predict where to reinforce or deploy flexibility before constraints form and to target the optimum time to reinforce.
- Using LV monitoring and control to:
    - get more from existing assets by safely operating networks closer to limits;
    - use lower cost smart interventions which depend on real-time data; and
    - make more informed and coordinated network interventions.
- Through a combination of strategically placed monitors in combination with advanced analytics to achieve high levels of visibility of the distribution network to a high degree of accuracy.

Changing customer needs and the decarbonisation challenge require an increasingly decentralised and digitised energy system. That includes the value in sharing data openly both within the sector and with wider stakeholders. Data is providing visibility to stakeholders of the opportunities for engaging with network operation and informing their planning decisions. All DNOs have data portals that facilitate data access.

There is an increasing need for collaboration, both vertically and horizontally through the energy system and data and digitalisation will be a key enabler for this. Common data and communication standards are necessary to drive this collaboration and the coordination necessary for a whole energy system that operates efficiently together.

However, we must be alive to security concerns. Whilst open data is widely recognised as a key enabler of decarbonisation, we need to be alive to both cyber security and wider infrastructure security concerns. The electricity networks are collaborating to work with the industry to balance priorities, ensuring there is no compromise to security.

CONNECTING TO THE DISTRIBUTION NETWORK

8. What barriers or delays are currently being experienced in the process for managing connections to the distribution network? Why do these occur? To what extent are these issues likely to be addressed by the government and Ofgem's Connections Action Plan? Please provide specific examples, differentiating between different users (e.g. domestic and non-domestic demand, distributed generation, etc.)

For the majority of customers, the DNO is not the blocker. The issues are concerned with transmission queue management, congestion and planning challenges. However, through the ENA all DNOs and TOs are collaboratively working to resolve any barriers and delays for connections to distribution networks, however these can occur for a range of reasons such as:

- Planning requirements – requirements on DNOs to apply for planning permissions for reinforcement or additional assets, such as section 37.
- Transmission related network reinforcement – can result in delays as far out as the late 2030s.
- Connection queue size – the current pipeline of accepted offers which are yet to be connected far outweighs the current requirement for the country to reach net zero.
- Inconsistencies in customer treatment between Transmission and Distribution.

Through the Ofgem and DESNZ Connection Action Plan, Networks' fair and faster connections plan outlined in the ENA's Rising to Britain's Net Zero Challenge, and the NESO's tactical and strategic connections reform initiatives, DNOs are working collaboratively with Ofgem, the Government, TOs and NESO. Areas which are being prioritised are:

- Distribution Queue Management - this is allowing for a better management of connection customers which are in the pipeline but are not progressing on milestones and therefore are holding capacity which is not being utilised. This work is ensuring that capacity is freed up for customers who are progressing by removing those who have stalled projects.
- Transmission/distribution technical limits – due to the timeframe being placed on Transmission works to be completed, work has been developed to allow for generation to be connected ahead of the date of the transmission works through the utilisation of a non-firm connection.

- Battery storage assumptions – through changing how networks study battery storage this has allowed connections to progress without the need for reinforcement and is enabling more connections and better utilisation of distribution networks.
- Queue entry and management – ensuring all applications for connections are to a standard which can progress, managing milestones set out within all offers and ensuring projects progress.
- Transmission costs to distribution connections – looking at how costs are passed through from TOs to DNO connecting projects, ensuring a more consistent and fair approach.

Areas to further address are to ensure the current framework for changing of industry codes, framework and licences are agile to ensure that any works resulting from the Connections Action Plan can be implemented at pace.

Finally, simply connecting the whole queue is not what Britain needs (the current queue includes 659GW of generation and storage projects – 2.4x the capacity required for our most ambitious 2050 ("Leading the Way") scenario); policymakers (Ofgem and DESNZ) should also consider how to prioritise access to the network to enable the most efficient and effective network for all customers and consumers.

9. How does transmission network capacity cause delays in connecting to the distribution network and what is the scale of the challenge? How far are these issues addressed by transmission network policy, particularly the government's Transmission Acceleration Action Plan? Please provide examples, where possible.

Unprecedented numbers of applications for new and amended electricity network connections have emerged in recent years, posing problems for the whole system. In several parts of the country, new connection dates for transmission connections are in the 2030s, and around half of contractual distribution connections are currently contingent on transmission upgrades.

For the majority of customers, the DNO is not the blocker. The issues are concerned with transmission congestion and planning challenges. The majority (172 of 198) of Grid Supply Points (GSPs) are constrained as a result of transmission constraints and distribution customers face considerable delays as a result.

Whilst constraints on the distribution network can be resolved in relatively short timescales, and over 57GW of customer projects can connect to the distribution network without undue network delay, this only represents c. 35% of the queue. The remaining 65% of the distribution queue, over 108GW of customer projects, are dependent on or being assessed for transmission reinforcement. Transmission constraints also can take considerably longer to resolve in comparison.

TOs and DNOs are working collaboratively to ease the blockage and significant progress has been made, but there is more to do.

- We are supportive of the actions being implemented through the Connections Action Plan, including those which built on the NESO 5-Point Plan and the ENA 3-Point Plan.
- Technical limits have been successful in releasing capacity and accelerating customer connections.
- Strongly supportive of reforms which move the T-D boundary investment decisions away from the reactive response to customers connections and into a more considered, strategic decision-making process; considering the needs of current and future customers and developing capacity aligned to their forecast growth to avoid lengthy delays to their connections journey.

There are however a number of actions that can be taken to alleviate immediate constraints:

- Provide more transparency and equitability of queue position to all customers - across transmission and distribution.
- An assessment and change to the treatment of storage - reflecting actual operating regimes.
- Apply realistic and consistent planning assumptions – acknowledging there is always attrition in the queue.
- Optimise the queue to enable 'shovel ready' projects to connect and eject projects that are clearly not progressing.
- Making the connections applications process simpler and faster, with an improved customer experience.
- Agree 'technical limits' between NESO and DNOs to enable more flexible connections.

10. How could processes requiring contact with, or work from, the distribution network operators be improved? Is there a case for more standardisation of processes between network operators to improve the customer experience and, if so, where would standardisation be most beneficial?

ENA is working across multiple collaborative cross industry fora to provide transparency and guidance on the distribution connections process, e.g. DfT's Freight Energy Forum, DESNZ Electrification of Heat Task Force and the ENA led Fleet and Depot Decarbonisation Forum.

As a result of the discussions ENA is leading a new set of connections guidance materials that will be applicable to multiple stakeholders across multiple industries. Stakeholders are requesting plain language guidance and clear steps with data requirements for them to follow. This guidance will provide that as well as identify areas that networks can provide more consistency in the connections process.

One area that is a key focus of this work is clearly outlining the data requirements for connections surgeries. If applicants can provide key information in advance of surgeries about the options they are considering for a connection it can greatly speed up the process for all parties.

Through the Connections Action Plan, ENA is leading on actions to ensure more consistency between DNOs. Many of these have been implemented, including battery storage assumptions and single source of connections data links (held on ENA's website) with some ongoing work to look at more detailed processes and alignment between all DNOs for a better customer experience.

11. What best practice examples exist of network operators improving processes and information for customers looking to connect to the network (either for demand or generation purposes)?

The seven UK DNOs (including Northern Ireland Electricity Networks) have collaborated to provide Connect Direct, a new national digital platform for connections applications for domestic LCTs. This process is:

- **Better** - by consolidating paper-based forms down to a single nationwide online process.
- **Faster** - by streamlining the application form, asking fewer questions and is capable of providing instant responses to applications.
- **More accurate** - by automating parts of the form, not only DNOs now ask fewer questions, but they reduce errors, as well as being able to validate entries that are provided. This reduces the back and

forth between installers and networks and also means the networks receive more accurate data for network planning.

All DNOs, TOs and NESO have worked with ENA to provide a clear digital list of all connections related data and links available on their websites. These are hosted on the ENA website: Connection Data.

Annex

Table 1 - Land rights and consents required by networks

Type	For	Requiring	Legislation
Acquisition of Land	Substations	Freehold purchase or Leasehold purchase	EA 1989 Section 10 Schedule 3 Compulsory Purchase Order Landlord & Tenant Act 1954 Section 23 of Part II
Acquisition of Rights Over Land	Overhead lines and underground cables	Wayleaves/Easements/Servitudes	EA 1989 Section 10 Schedule 4 Necessary Wayleaves EA 1989 Section 10 Schedule 3 Compulsory Purchase Order EA 1989 Schedule 6 Para 9 Works to existing equipment
		Street Works Consents	EA 1989 Section 10, Schedule 4 para 1
Planning Permission	Overhead lines	OHL Consent	EA 1989 Section 37 Consent required for Overhead Lines Formal statutory consultation with the Local Planning Authority – 'Form B process' The Overhead Lines (Exemption) Regulations 2009
	Substations and cables	Planning Permission	Town & Country Planning Act 1990 Town & Country Planning (General Permitted Development) Order 2015

Table 2 – Overview of weaknesses across some areas of the current framework

Acquiring land and rights over land
Whilst networks operators endeavour to secure land and rights over land without requiring use of their statutory powers this is not always possible. Typically, it can become necessary to exercise statutory powers where a landowner's terms are judged excessive, with the only alternative to adopt a significantly more expensive engineering solution. Statutory powers are a last resort because they are expensive, time-consuming to use and indicative of a failure in the normal dialogue between the landowner and the network operator or landowner expectations that exceed reasonable compensation. The cost in utilising these powers might be £50k-£100k and incur a delay of at least a year. These costs are reflected in customers' electricity bills and also connection charges for new customers. Delay in the acquisition of land and rights over land may therefore

impact the timely delivery of net zero-related reinforcement works and new connections. Swifter resolution of such matters would be desirable to ensure efficient delivery of infrastructure.
Planning Permission / Permitted Development
Network operators install 11kV substations that conform to the size requirements stipulated by the permitted development regulations. Looking ahead the expected increased demands on the network is likely (at least for some licensees) to require multiple or larger 11kV substations. If new larger substations exceed the permitted development threshold (29m³) this will trigger the requirement for a full planning consent. This is a time consuming and costly process, that will feed through to impacting electricity bills and the timescale and cost of net zero-related reinforcement works and new connections. Amendment of permitted development regulations e.g. to cater for larger substations would help ensure efficient delivery of infrastructure. It should be noted, permitted development covers cabling works too and the criteria could be widened to ensure cabling proposals can be secured more swiftly in areas where permitted development rights are currently invalid (designated areas etc.)
Section 37 Exempted Works
The Exemption Regulations were introduced to facilitate minor alternations to an existing overhead line without the need for a further s.37 consent. However, as we look ahead to the types of works that might be required to our networks to accommodate net zero-related loads, there are some which might be considered to constitute minor alterations (in many cases not requiring of additional landowner consents), which nevertheless would require a new s.37 consent and include the following: • To uprate from a single phase (2-wire) to three phase (3-wire); • Alter conductor type from bare to covered within a Protected Landscape • Uprate Nominal Voltage of the overhead line from 6.6kV to 11kV or 11kV to 33kV
Sch. 4 Para.1 of The Electricity Act
Does not extend powers to enable a DNO to install a new underground electric cable within a Private Street without the consent of the Street Manager, who should not unreasonably withhold consent. However, instances can still arise where consent requests to connect a new supply to a private resident or Charge Point Operator, are unreasonably withheld, necessitating the need for recourse to DESNZ.