Written evidence submitted by The Independent Renewable Energy Generators Group (GRI0082)

Introduction
IREGG was established in 2012 and is a partnership of independent renewable energy generators and developers as well as the manufacturer Enercon, which have together invested hundreds of millions of pounds in UK energy infrastructure.

IREGG represents the main alliance of independent pure-play green energy investors and generators and comprises (owns/operates) nearly one-third of UK onshore wind, with a pipeline that would more than double the existing MW.

IREGG members include:

1. **Renantis:** a renewable energy company with headquarters in Milan, Italy with two offices and a significant number of operational and development projects in the UK.

2. **Banks:** a County Durham-headquartered renewables business operating and developing wind and solar projects.

3. **BayWa**: a German headquartered solar, wind, and bioenergy company.

4. **ERG**: an Italian headquartered company and one of the leading European producers of energy from renewable sources.

5. **Boralex**: a leader in the Canadian market and France's largest independent producer of onshore wind power, with facilities in the United States and development projects in the UK.

6. **Enercon**: a German-based wind turbine manufacturer and one of the world's leading companies in the wind energy industry.

7. **Fred. Olsen Renewables**: a Norwegian-headquartered onshore and offshore wind business with currently ten operational wind farms in the UK (Scotland). The group includes Scotland's Natural Power consultants and offshore specialists Fred. Olsen Ocean.

8. **Ventient Energy**: a pan-European renewable energy business and one of the largest independent generators of onshore wind energy in Europe.

9. **RES**: the world's largest independent renewable energy company, which has delivered more than 23GW of renewable energy projects across the globe.

10. **EDP:** EDP Renewables is a global leader in the renewable energy sector and the world's fourth-largest wind energy producer.

Questions

1. **Does the current national and DNO grid deliver the capacity needed for the future and, if not, what are the solutions? <u>and</u>**
2. **Has the organisation of the National Grid proved a barrier to the installation of renewable energy sources, and if so, what could be done to remedy this?**

The greatest problem the UK energy system faces is the cost of a decade-long false economy of grid under-investment fostered by endemic optimism-bias in NGESO constraint forecasting, and exacerbated by signals from Ofgem to the Transmission Owners to avoid investment if there was any perceivable risk of stranded assets.

It is this that is the largest driver of high constraint costs, because grid build out does not anticipate, nor keep pace with, necessary electricity generation capacity build out.

Although large numbers of proposed developments have applied for distribution network connections, very few are progressing to energisation, mainly citing the lack of grid capacity and cost of network reinforcement.

As set out below in detail in our answer to questions six and seven, the way to remedy this issue is not to introduce nodal or zonal pricing, but rather to continue to pursue distribution-led approaches in combination with essential investment in the grid.

3. **Should there be more innovation and devolution in the development of the Grid?**

As outlined above, the greatest problem the UK energy system faces is the cost of a decade-long false economy of grid under-investment fostered by endemic optimism-bias in NGESO constraint forecasting, and exacerbated by signals from Ofgem to the Transmission Owners to avoid investment if there was any perceivable risk of stranded assets.

It is this lack of investment in the grid which most urgently needs to be addressed. In addition, IREGG members welcome innovation which could better enable the UK to deliver the net zero transition in a fair, clean and affordable way - for example, regional flexibility markets.

4. **What changes should be made to the planning system to enable it to increase the use of renewable energy? <u>and</u>**
5. **Is our planning system able to deliver more rapid development of new local infrastructure?**

To realise its commitment to net zero and security of supply ambitions, the government needs to adopt a planning policy framework that is supportive of onshore wind.

In its redrafted form, the National Planning Policy Forum (NPPF) severely hinders investment in the onshore wind industry and its supply chain due to the high-level of risk and uncertainty it creates. The building of a possible onshore wind pipeline in England is extremely limited as a result of this – and also, in the short to medium term, due to the legacy of the planning 'moratorium' on onshore wind in England.

It is right that the planning system should enable build-out in England of a widely popular technology in onshore wind. Policymakers should also consider significant permitting simplification processes for repowering projects and a priority rule for the repowering of onshore wind plants. Germany has implemented this along with the EU's emergency regulation that ensures the permit-granting process (including EIA and grid permit) for repowering projects has a maximum deadline of 6 months.

IREGG members further support some of the Winser Report recommendations to facilitate transmission build – for example, the Strategic Spatial Energy Plan; addressing community acceptability with guidelines and payments; and streamlining planning consents.

However, these interventions alone will not be sufficient to deliver the amount of new onshore wind we will need within the timeframe required to meet the government's 2035 deadline for decarbonising the electricity system - or to achieve its 2040 energy security targets and 2050 net zero ambitions.

It will take time to build up an English onshore wind pipeline – the pipeline that currently exists is in Scotland, and it remains the case that the majority of the UK's prime wind sites are located in and offshore of Scotland. The most impactful interventions the government could make to strengthen the UK onshore wind pipeline, and ensure we are able to bring forward sufficient new plant, centre on removing regulatory obstacles to building onshore wind in areas where the UK is windiest. The two most significant such obstacles are outlined below:

1. **Locational Penalty Charges**: The objective of locational penalty charges within TNUoS is to encourage the development of energy assets in locations close to major UK demand centres, aiming to minimise the cost of grid investment as a result. This distorts the market to incentivise a false economy, because it promotes the development of a less efficient, less cost-effective and more carbon intensive energy system that inflates the total cost of power generation to avoid investment in networks.
2. **Locational Marginal Pricing**: Locational Marginal Pricing (LMP) proposals in the government's ongoing Review of Electricity Market Arrangements (REMA) would torpedo the Scottish investment pipeline without a viable alternative, stymying the pace and scale of progress to net zero. LMP risks distorting the GB energy market as annual constraints costs provide a proxy signal for grid investment; high constraints costs over several years means that investment is warranted (and should have been forecast to approve preventative grid upgrades). Nodal pricing only includes a grid investment signal insofar as the markets are willing to price it – and they tend to be more short-term looking. This has been shown to undervalue grid investment, resulting in even greater adverse costs[1].

In conclusion, while we welcome moves to 'unlock' onshore wind in England, this is not the most significant barrier to sufficient UK onshore wind buildout. The greater threat to UK onshore wind buildout is the multi-decade-long false economy of grid under-investment, fostered by endemic optimism-bias in NGESO constraint forecasting. This has meant that grid build-out has not anticipated, nor kept pace with, necessary electricity generation capacity build-out.

6. **Would regional, or nodal, pricing of energy facilitate a more flexible development of Grid infrastructure? and**
7. **What can be usefully learned from power transmission systems in other countries?**

As highlighted in our answer to questions one and two, the greatest problem the UK energy system faces is the cost of a decade-long false economy of grid under-investment fostered by endemic optimism-bias in NGESO forecasting, and exacerbated by signals from Ofgem to the Transmission Owners to avoid investment if there was any perceivable risk of stranded assets.

This is the largest driver of high constraint costs because grid build out does not anticipate, nor keep pace with, necessary electricity generation capacity build-out. Proposals for zonal or nodal charging (LMP) risks worsening this cost, by distorting the market through removing a key proxy signal for grid investment, and leaving the system prone to underinvestment.

Changing to a system of LMP rather than investing in the required grid infrastructure will further exacerbate these crises, as it will deter the investment in new renewable capacity in the north of GB necessary to wean the UK off fossil fuels altogether.

It would take just £0.3bn annuitised grid investment to almost eliminate the ESO's forecast £2.3bn annual constraint cost[2]; far cheaper than the cost of the economic damage to UK PLC that a move to LMP without pre-emptive grid investment would risk.

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[1] Texas Power Crisis Revealed Flaw in Market's Design ("Using Texas as a case study... decentralized energy markets are prone to underinvestment in resiliency against rare events."), Cornell Chronicle 8/2/22, [Texas power crisis revealed flaw in market's design | Cornell Chronicle]

[2] "Constraints costs could reach £2.3bn p.a. by 2026" ESO NZ market reform phase 3 conclusions, slide 6, presented 22/3/2022. However, comparing NGESO ETYS power flows with allowed East-Coast HVDC project (EHVDC) costs. 6GW of new connectors (three new links) enables c.90% of constraint to be avoided. Averaging 2024, 2025, 2026 – the "mid-2020s" forecast peak of constraints – shows:
• Scotland-to-England capability of 7.1 GW in this period

a) NGESO's own modelling shows that constraint costs will massively reduce once the sub-sea bootstraps that they themselves delayed undertaking have come online in the late 2020s – highlighting the scale of false economy created by NGESO's under-investment in sub-sea bootstraps and Ofgem's historic refusal to future-proof the grid.

b) Nodal charging risks distorting GB energy market as annual constraints cost provide a proxy signal for grid investment; high constraints costs over a number of years means that investment is warranted (and should have been forecast to preventively approve grid upgrades). Nodal pricing only includes a grid investment signal insofar as the markets are willing to price it – and they tend to be more short-term looking - this has been shown to undervalue grid investment, resulting in even greater adverse costs[3].

c) Artificially creating a market mechanism that will *block* cheap power from Norwegian hydro and Irish wind, which NGESO has presented as an advantage of nodal and zonal pricing options (instead of creating a system that can accept cheap and green power from Norway and the island of Ireland), is a false economy – just like those historic failures to future-proof the GB grid. For example, expanding grid investment to enable UK consumers to take advantage of low-cost imports from Scandinavia would bring down the average cost of electricity at a cost (annuitized grid investment) of roughly 1/10th of the forecast annual constraint cost cited as the impetus for nodal pricing[4]. In addition, the ESO's Holistic Network Design (HND) pathway could address many of the issues. Implementing the recommendations from the HND would mitigate the overall level of constraints at key boundaries, such as the Scotland/England boundary, while also better preparing the system for the expected expansion of offshore wind in the north.

Current constraint costs are high, not because of the volume of constraints, but primarily due to the cost of balancing actions. This is heavily driven by the cost of turning-up CCGTs in England, due to the extremely high cost of wholesale gas - LCP's assessment of 2021 constraint showed that 75% of ESO payments (and 85% of the net total cost of constraint) were made to fossil fuel plant in the South[5]. There are two key implications of this situation, which the LMP agenda ignores completely:

1. The lack of grid investment by the transmission licensees to date is already contributing to the global gas crisis and exacerbating climate change, by preventing the UK from fully exploiting its existing homegrown green energy resources, forcing it to squander cheap renewable power when it is most urgently required.
2. Changing to a system of LMP rather than investing in the required grid infrastructure will further exacerbate these crises, as it will deter the investment in new renewable capacity in the north of GB necessary to wean the UK off fossil fuels altogether.

There is also significant anecdotal evidence (from the ESO themselves) that they do not manage constraints in the most cost-effective way (see Case Study Below). Given that the ESO is seeking to re-write the entire GB trading arrangements, and is using constraint costs as a key justification for

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• Average maximum to cover 90% of power flow situations in this period is 13.4 GW1 – a shortfall of 6.3 GW
• To underline the point, capability rises to 12-15 GW in the early 2030s, when constraint spend is forecast to fall substantially.
Using EHVDC approved costs, multiplied 150% for 3 links instead of 2, gives +6.0GW of capability

[3] Texas Power Crisis Revealed Flaw in Market's Design ("Using Texas as a case study... decentralized energy markets are prone to underinvestment in resiliency against rare events.."), Cornell Chronicle 8/2/22, [Texas power crisis revealed flaw in market's design | Cornell Chronicle].

[4] Comparing NGESO ETYS power flows with allowed East-Coast HVDC project (EHVDC) costs. 6GW of new connectors (three new links) enables c.90% of constraint to be avoided. Averaging 2024, 2025, 2026 – the "mid-2020s" forecast peak of constraints – shows:
· Scotland-to-England capability of 7.1 GW in this period
· Average maximum to cover 90% of power flow situations in this period is 13.4 GW1 – a shortfall of 6.3 GW
· To underline the point, capability rises to 12-15 GW in the early 2030s, when constraint spend is forecast to fall substantially.
Using EHVDC approved costs, multiplied 150% for 3 links instead of 2, gives +6.0GW of capability for cost of £5.1bn – equating to £270m equivalent annual cost of investment, using RIIO-T2 financial parameters.

[5] LCP - Renewable curtailment and the role of Long Duration Storage, May 2022, https://www.drax.com/wp-content/uploads/2022/06/Drax-LCP-Renewable-curtailment-report-1.pdf

doing this, it is important to determine how much of these costs are down to the ESO's own (mis)management.

Case Study: Foyers - SSE's pumped hydro plant.

· A significant part of constraint costs is due to NGESO's processes. To give an example, SSE operates a 300-megawatt pumped hydro plant; Foyers, which they deliberately optimise around constraints when high winds are forecast, by positioning the plant such that it's effectively empty, and ready to pump to alleviate constraints.

· However, NGESO doesn't call it, because NGESO's theory is that once the pumped storage reaches capacity, it immediately then has to empty itself again.

· From NGESO's perspective, this means it will then stop pumping and start exporting, which would make the constraint worse.

· So, rather than bidding on the pumped storage, they instead bid off a significant amount of wind at negative prices (paying premium offers to increase thermal plant output south of the border) and the pumped storage is left unused. Therefore, rather than – in effect – being paid by the pumped storage to increase demand, NGESO pays premium constraint costs, at much higher cost to consumers than needs to be the case.

· This behaviour also threatens the business case of future investment in flexible assets in Scotland, delaying the deployment of other Pumped storage generators, which, if properly utilised, would be able to reduce the constraint burden on the England/Scotland boundary.

Texas is often cited as a case study for the potential benefits of adopting a locational marginal pricing mode. However, Texas' successful implementation of clean energy expansion and nodal pricing was critically dependent on additional key ingredients, principally pre-emptive investment in 3,500 miles of network upgrades providing 20GW additional capacity to connect remote Competitive Renewable Energy Zones (CREZ) to the major centres of demand like Houston and Dallas.

This transmission investment ensured that Texas wind energy curtailment fell from 17% in 2009 to 0.5% in 2014. For Texas' experience to evidence that nodal pricing would not negatively impact UK clean energy generation investment, the UK would need to ensure that 'other things are equal' with Texas, by boosting pre-emptive grid capacity investment to remove constraints and adopting a Texas-style planning system before it introduced a nodal pricing arrangement. If anything, the Texas approach of concentrating renewables in remote zones, far from demand centres but with the best natural resources, closely mirrors the opportunity for Scotland in GB, and is the complete antithesis of NGESO's vision for nodal pricing.

The logical conclusion from Texas is that what the GB market really needs is significant, strategic grid investment, which the current onshore transmission regime has consistently failed to deliver.

Nor do the very few other international experiences demonstrate nodal pricing to foster a substantial acceleration in clean power generation against a background of historic grid under-investment that GB has experienced:

- Despite very high load factors giving New Zealand enormous potential for wind power, hardly any (less than 800MW) has been developed by UK or Texas standards. Nor is there much grid-connected solar (186MW by December 2021). Decades-old giant hydro and geothermal power plants have provided around 70% of New Zealand's power for many years, with gas and coal making up most of the rest of its energy generation landscape. New Zealand's low population density, split island geography and very low levels of wind and solar penetration make it an irrelevant comparison with GB. Its lack of salience makes it difficult to understand why it is cited as a relevant comparison, as it does not show how nodal pricing supports the expansion of the clean energy that the UK needs.

- Despite California having the available land and wind resource to support giant wind farms of 1.5GW scale, a lack of the equivalent of Texas' CREZs has led its wind farm capacity to stagnate at a much lower level than the UK (c7.9GW[4]), barely growing since 2012 (5.5GW). California's experience certainly does not provide evidence that nodal pricing supports the expansion of wind power that the UK needs.

Introducing Texas-style nodal charging in the UK without first introducing Texas-scale pre-emptive grid upgrades risks generating greater costs than it saves and imperilling UK energy security.

Any economic benefits realised by data centres relocating from the M25 to Scotland would be outweighed by the uneconomic electricity costs that would be created by introducing nodal charging will inevitably create for any businesses that cannot relocate from urban centres in the south of England – undermining the international competitiveness of south-East England and London in particular. Specific measures could give locational energy discounts to energy intensive demand users, including green steel, battery construction and hydrogen electrolysers in Scotland, without creating the wider risks that nodal charging entails.

Any other economic benefits would be dwarfed by the cost escalations for clean energy generation that nodal charging would create if introduced without pre-emptively investing in Texas-scale grid upgrades and Texas-style planning reforms.

Implementing LMP without increasing grid capacity will not solve the fundamental problem, but will simply transfer cost from one bucket to another, and would risk increasing costs overall

There are several flaws to the presumption that nodal pricing will incentivise significant movement of demand from South to North:

- Firstly, a significant price differential already exists that should encourage such a move, via the locational element of the TNUoS charge.
- Prior to an Ofgem regulatory change, customers in Scotland received a negative charge signal, yet this did not lead to widespread movement North, underlining that there are many other factors which influence where many businesses locate that are more significant than wholesale power prices.
- Proponents of LMP have not yet presented any evidence, qualitative or quantitative, as to what level of price difference would actually incentivise movement of demand on such a scale as to actually alleviate forecast constraints (i.e. what is the price elasticity of demand to power prices, bearing in mind sunk costs and other key economic factors).

<u>What do the modelling and international case studies show?</u>

Modelled savings to energy costs from Texas-style nodal charging reflect flawed assumptions:

1. of a Texas-style planning free-for-all in southern England;
2. of continued false economies in grid investment that would otherwise bring greater savings to bill payers;
3. of clean energy site availability and cost-effectiveness;
4. that the UK grid is reformed to operate Texas-style with Competitive Renewable Energy Zones (CREZ) building transmission networks to connect areas of renewable energy potential to areas of high demand ahead of the generation actually signing these contracts for transmission;
5. of consumer impacts sufficiently large to relocate demand from southern England to Scotland that would devastate businesses that could not relocate.

A major claimed benefit of nodal pricing is that the availability of clear market signals will lead generation to locate closer to areas of demand. However, there is little evidence that this actually occurs. In fact, independent analysis by the University of Alberta of the impact of nodal pricing in Texas on generation has shown that a locational price signal was too volatile and unpredictable to shape the majority of generation investment decisions – instead the location of new generation was primarily determined by factors such as the planning system, availability of required infrastructure, land suitability, availability and cost.[9] The International Association for Energy Economics concluded: "factors other than nodal prices are more likely drivers of utility-scale generation capacity investment location decisions in Texas".[10] Given that these constraints occur in as large and relatively less densely populated market as Texas, the idea that they would not also be limiting factors in a much more densely populated country like the UK lacks credibility.

Texas did not introduce nodal charging to create a locational signal for clean energy to relocate from the best sites in west Texas and the panhandle to closer to demand centres in Houston, Austin and Dallas, and nor did it expect consumers in the Texas triangle of Houston, Dallas, Austin and San Antonio to relocate to West Texas (however, there is evidence indicating that crypto-currency mining is doing so.) For the UK to realise the 'benefits' of Texas nodal charging it needs to take the Texan approach to solving constraint costs: nodal charging did not preclude the significant deployment of clean energy generation in ERCOT after 2010 precisely because via the Competitive Renewable Energy Zones (CREZ) programmes Texas pre-emptively built 3,500 miles of new transmission lines with a total capacity of almost 20,000MW to solve constraint costs, by connecting areas of renewable energy potential to areas of high demand ahead of the generation actually signing these contracts for transmission.

The $6.8 billion cost of Texas CREZ grid expansion is more than offset by an estimated $2 billion per year in savings from unleashing cheaper wind power.[6] In fact, power prices have fallen so dramatically that many of the state's coal plants struggle to compete. It also massively reduced constraints:

Under a nodal pricing regime, curtailment becomes a much bigger commercial risk to generators, as they are not compensated, and therefore creates a negative investment signal that will increase costs or retard investment or both. It is unclear how such an impact would be compatible with the acceleration of clean generation deployment the UK needs for 2035 100% clean energy target, and for 2050 Net Zero – international evidence (e.g., from Texas and others) does not show otherwise.

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[6] Why Renewable Energy Really is Bigger In Texas - Morning Consult