# REMA – ESO Response

ESO's response to BEIS' Review of Electricity Market Arrangements consultation, informed by our Net Zero Market Reform (NZMR) analysis. This was submitted on Monday 10th October 2022. This is a public response and will be published by BEIS with all responses to the consultation.

## Executive Summary

### Introduction:

REMA represents the most far-reaching review of energy market arrangements since privatisation. Efficient and coherent electricity markets will be fundamental to achieving net zero. We, the Electricity System Operator (ESO), therefore hugely welcome REMA's long-term focus, and believe its outcomes will be transformative in delivering decarbonisation, system security and value for consumers.

The ESO has a dual responsibility: first, to operate and balance the electricity system in real-time, and second, to work with Government, Ofgem, industry and consumers to guide GB on the resources, markets and networks needed to deliver a future energy system that is secure, fair and clean for all.

We fully support the government in acting decisively to help consumers through the gas price and cost of living crisis. This does not detract from, and indeed reinforces, the need for GB to focus on the long-term vision and strategy for net zero markets – ensuring we are delivering a clean, secure and reliable system will help to mitigate the impact of any future crises on consumers.

This response outlines the ESO perspective on what market design reforms are needed to achieve a decarbonised electricity system by 2035. In summary, we believe that:

- Significant reform is needed to meet the scale of GB's decarbonisation ambitions. Defining a clear, holistic long-term vision, with a coherent and well-communicated transition, is vital
- In a high-renewables system, nodal pricing, which reveals the true value of electricity at different times and locations, is a critical enabler for both efficient investment and real-time operation
- As electricity generation becomes more weather-dependent, centralised market clearing and dispatch is increasingly appropriate for coordinating generation and demand
- Support mechanisms for low carbon technologies are key to maintain investor confidence to ensure investment at pace. Design enhancements that allow increased price exposure in operational timeframes could reduce system cost
- Retaining investor confidence during implementation of new market arrangements will be crucial. Transitional measures will be required for existing investments. Minimising any period of uncertainty should be is a priority.

### The ESO Net Zero Market Reform Programme:

We launched our Net Zero Market Reform (NZMR) programme in early 2021, to examine holistically the changes to GB electricity market design that would be required to achieve net zero. In May 2022, we published the third phase report relating to the elements of market design that address operational issues. We are currently undertaking the fourth phase of the programme, focussing on market design mechanisms to deliver investment outcomes, as well as developing holistic market design packages that combine investment and operational elements. Such fundamental and wide-ranging reforms would impact the whole energy system, so we also consider wider system implications (e.g. gas, hydrogen, heat) from the outset.

We summarise below key points from our REMA response, informed by our NZMR programme analysis.

## The wholesale market price must reflect where and when electricity is generated and consumed

In a high-renewables system, where and when electricity is generated and consumed is critical to its value. The current market design fails to communicate this value with sufficient accuracy, resulting in wasted renewable generation, rising balancing costs and suboptimal use of network capacity. Consumers are bearing excessively high system operation costs as a result, and without more effective locational signals will ultimately incur unnecessary cost from inefficient buildout of new energy production and transmission capacity.

## Nodal pricing could deliver maximum value for consumers and accelerate decarbonisation

Nodal pricing reflects the value of electricity at high locational and temporal granularity. This would incentivise flexible resources to complement renewable generation, enabling GB to maximise use of its clean resource.

For regions where renewable supply commonly exceeds demand, nodal pricing would greatly reduce the frequency with which gas sets the price, driving down wholesale energy costs and benefitting consumers as a whole. Recent studies suggest locational pricing would save consumers c.£30bn by 2030 (ESC & Octopus) and £59bn by 2050 (Aurora). We expect a forthcoming Ofgem technical assessment to provide further evidence on consumer benefits from locational pricing. Ensuring nodal pricing accounts for consumer distributional impacts would be key to its success, and we believe there are several credible ways that it can be implemented to avoid or manage concerns around regional price variation.

## Centralised dispatch could offer substantial efficiency improvements through better alignment of the market with the physical and energy balancing needs of the electricity grid

The choice of self or central dispatch determines how resources are selected to run. The current GB market is theoretically self-dispatch, meaning decision-making is decentralised; however, the increasing divergence of wholesale market outcomes from the physical capability of the grid means that ESO is frequently unwinding dispatch decisions to secure system reliability. We believe this structure is inefficient and results in unnecessarily high balancing costs.

Phase 3 of NZMR found that central dispatch combined with nodal pricing would most effectively coordinate the electricity system by enabling the market to resolve system constraints. Irrespective of locational wholesale market design, we believe more centralised dispatch has several advantages in a decarbonised system: from improved pooling of information in operational timescales, price visibility, and enabling co-optimisation of energy and ancillary services. We are therefore assessing the potential for a centrally dispatched wholesale market design, both with and without locational energy pricing, to improve balancing and overall system outcomes.

## Investment support mechanisms are key to reaching net zero; however, reform is needed to ensure assets contribute to system security and reliability, across supply and demand

Significant market reform inherently creates uncertainty for investment, but a clear long-term vision, transparent process and a well-managed transition can mitigate much of that uncertainty.

The Electricity Market Reform (EMR) policies have successfully facilitated early-stage investment in low carbon technologies. We believe both reformed and additional policy instruments are now required to achieve a cost-efficient balance of weather-dependent and flexible resources.

The wholesale market and dispatch design reforms set out above are the critical first steps in aligning investment signals with system needs: sending accurate and granular signals for assets across the system will send clearer investment signals for flexible technologies and will avoid or mitigate renewables price cannibalisation.

While we have yet to conclude our NZMR Phase 4 analysis of investment market design, we have identified the following key issues and considerations for solutions:

- Asymmetry of both market signal exposure and financial de-risking policy support across supply- and demand-side will lead to unnecessary renewables curtailment and price cannibalisation. Future market and policy design can address this imbalance to incentivise an optimal mix of renewables, demand and flexibility.
- CfDs are needed to drive investment in zero carbon technologies at the pace required, but the current design can disincentivise generators from reducing system costs by shielding them from real-time price signals. We believe CfD design enhancements that introduce some wholesale price exposure are desirable.
- The Capacity Market does not always accurately reward resources for addressing emerging system needs. Design options that link renumeration more closely to system value, including Reliability Options and Reverse Reliability Options may be preferable to the current design. We are aware of the need to carefully manage the exit of high carbon plant and therefore also suggest further exploring strategic reserves.

## Proposals to split the wholesale market could risk negative unintended consequences. Alternative mechanisms are available to address the issues of expensive price-setting resources

While there is no real-world evidence to draw upon (as it is not a market design that exists anywhere globally), we are concerned that splitting the wholesale market by technology type to move away from marginal pricing risks unintended consequences. These could include:

- Inaccurate signals of system value and limited price exposure of some parties weaken incentives to help reduce system costs, driving increased balancing costs
- Perverse incentives for cross-border trading if neighbouring countries do not split their markets
- Reduced competition and liquidity in balancing and ancillary services markets, where intermittent renewable generation would not be incentivised to participate

To address gas setting the marginal price of electricity, alternative measures to market splitting in the short term include expanded use of CfDs. In the longer term, proven solutions such as nodal or zonal pricing would significantly reduce the prevalence of wholesale prices being set by gas. Measures to unlock full-chain flexibility would stimulate a far greater contribution from demand-side response and reduce dependency on gas flexibility. More generally, accelerating deployment of demand-side energy efficiency will reduce the number of periods in which gas is required to meet demand.

## ESO will continue to reform operability markets as we progress to net zero, but the simultaneous reform of wholesale markets and dispatch would result in much more efficient operability outcomes

ESO is undertaking extensive reform of its balancing services markets to ensure they are fit for net zero, delivering security and minimising costs as much as possible within the scope of the current wholesale market design. Improving wholesale market design via dynamic locational signals will make a substantial contribution to resolving existing inefficiencies in balancing services procurement and dispatch.

We commend again the long-term outlook, breadth and depth of this consultation. We look forward to working with BEIS, Ofgem and the wider industry to help design and deliver the market reform outcomes that REMA has set out to achieve for GB consumers.

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## Questions

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| | **Respondent type** |
|---|---|
| ☐ | Business representative organisation/trade body |
| ☐ | Central government |
| ☐ | Charity or social enterprise |
| ☐ | Individual |
| ☒ | Large business (over 250 staff) |
| ☐ | Legal representative |
| ☐ | Local government |
| ☐ | Medium business (50 to 250 staff) |
| ☐ | Micro business (up to 9 staff) |
| ☐ | Small business (10 to 49 staff) |
| ☐ | Trade union or staff association |
| ☐ | Other (please describe) |

# Acronym List

| | |
|---|---|
| BEIS | Department for Business, Energy and Industrial Strategy |
| BM | Balancing Mechanism |
| BSUoS | Balancing Services Use of System Charges |
| Capex | Capital Expenditure |
| CCUS | Carbon Capture, Utilisation and Storage |
| CfD | Contract for Difference |
| CM | Capacity Market |
| CRO | Centralised Reliability Option |
| CUSC | Connection and Use of System Code |
| DA | Day Ahead |
| DNO | Distribution Network Operator |
| DRO | Decentralised Reliability Option |
| DSO | Distribution System Operator |
| DSR | Demand-side Response |
| EAC | Enduring Auction Capability |
| ENA | Energy Network Association |
| ESO | Electricity System Operator |
| ETS | Emissions Trading Scheme |
| FES | Future Energy Scenarios |
| FOAK | First of a kind |
| FSO | Future System Operator |
| FTR | Financial Transmission Right |
| GB | Great Britain |
| GFM | Gird Forming Convertors |
| GSP | Grid Supply Point |
| I&C | Industrial and Commercial |
| LCCC | Low Carbon Contracts Company |
| MHHS | Market-wide Half Hourly Settlement |
| MRV | Monitoring, Reporting and Verification |
| OBP | Open Balancing Platform |
| Opex | Operational Expenditure |
| PPA | Power Purchase Agreement |
| RoCoF | Rate of Change of Frequency |
| RDP | Regional Development Programme |
| RRO | Reverse Reliability Option |
| TNUoS | Transmission Network Use of System Charges |
| VRE | Variable Renewable Energy |

## Response

# Chapter 1. Context, vision, and objectives for electricity market design

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

☒ Yes ☐ No ☐ Don't know ☐ No opinion

*Please expand on your response here:*
We broadly agree with the vision for the electricity system presented in the consultation document though suggest the following considerations.

**Consumer Empowerment and Consumer Fairness**

We welcome the inclusion of the third element of this vision, consumer empowerment and consumer fairness. BEIS' description outlines the balance that future markets must achieve between facilitating consumers to take control of their electricity use and not being unfairly exposed to price signals that they cannot respond to.

Our Future Energy Scenarios 2022 highlights that consumers being willing and enabled to engage with the energy system is crucial to unlocking flexible supply and demand, and to achieving net zero in the most cost-effective way between today and 2050; however, the extent to which consumer behaviour may change is highly uncertain. We believe substantial opportunities exist for consumers who adopt potentially flexible loads, and measures such as smart meters and demand response contracts/ tariffs. We also recognise the opportunity to engage through technologies and assets such as smart charging for electric vehicles, noting the high upfront costs of some low carbon technologies which would require industry and policy solutions to help reduce costs and provide additional solutions to those on the lowest incomes.

We note that the objectives of consumer empowerment and consumer fairness have not been included in the objectives or assessment criteria. As discussed further in our response to Q5, we support the principle that the assessment approach should allow options to be differentiated by their performance when assessed against criteria; however, we disagree with the application of this principle in so far as it has been used to exclude consumer empowerment and consumer fairness from the assessment criteria. It should be possible to differentiate many of the market reform options based on how far they facilitate these objectives.

**Role of Interconnectors**

We note that interconnectors are not mentioned in the vision for the electricity system presented. Given the dramatic growth in interconnector capacity expected over the next decades, and the major role they are likely to play in both decarbonisation and system security, the overall vision should consider how future market arrangements should influence interconnector capacity and operation.

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

☒ Yes ☐ No ☐ Don't know ☐ No opinion

*Please expand on your response here:*
As set out in the ESO Net Zero Market Reform Phase 2 report, we believe that the trilemma objectives of decarbonisation, system security (security of supply) and cost-effectiveness are key

goals for electricity market reform.

**Proposed changes to definitions of 'cost effectiveness' and 'security of supply'**

We disagree that minimising risks is always integral to a measure being cost-effective. We believe that risks should be placed on market participants who are best placed to manage them. Minimising risks without considering appropriate risk allocation may lead to sub-optimal cost-effectiveness for the system overall, ultimately increasing consumer costs. We consider the appropriate goal is optimisation, rather than minimisation, of risks.

We agree that REMA must achieve a reliable and secure system. The term 'security of supply' reflects the focus of the fossil-fuel dominated system we are currently transitioning away from. In our refreshed Net Zero Market Reform assessment framework we have renamed this objective 'energy security and system operability' to underline the importance of the operability dimension and of demand-side flexibility in future reliable system operation.

## Chapter 2. The case for change

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

☐ Yes ☒ No ☐ Don't know ☐ No opinion

*Please expand on your response here:*
We broadly agree with the key future challenges identified in the consultation. The first three of these challenges align closely with those identified in Phase 2 of the ESO's Net Zero Market Reform programme: the Investment Challenge, Managing Imbalances Challenge and Location Challenge.

**However, we propose the following considerations:**

***Investment in renewables assets (price cannibalisation) (p.27)***

Price cannibalisation forecasts are an indicator that there is market disequilibrium. Facilitating flexibility addresses the root cause of the problem, namely facilitating response from flexible assets to low-price periods. We believe this is most efficiently done by sending accurate and granular siting and dispatch signals through the wholesale market.

In GB, price cannibalisation is exacerbated by limited demand-side elasticity (the willingness to vary demand level in response to price variance). This is due to a combination of factors, including inaccurate price signals and a lack of incentives for consumers and suppliers to deliver demand response (limited smart meter rollout, market-wide half-hourly settlement not fully implemented until 2025, limited demand response tariff offerings or demand for them).

Improving demand-side elasticity would dramatically reduce the extent of price cannibalisation. This is evidenced by the analysis conducted by LCP on behalf of the ESO in the NZMR Phase 2 Case for Change, which included a projection of average power prices to 2050 for each of the net zero compliant 2020 FES scenarios. Baseload prices recovering from a trough at the end of this decade (of around £25/MWh) and returning to 2025 levels by the mid-2030s demonstrate the impact of increasing levels of demand-side response reversing the downward wholesale price trend. More flexible assets, such as storage, on the system will also protect against price cannibalisation as they will increase demand by charging during lower priced periods.

With the locational value of energy embedded in power prices and barriers to demand response removed, normal market forces would incentivise greater levels of demand to restore greater market equilibrium, tackling price cannibalisation.

***Investment in flexible low carbon assets and short-term investment in unabated assets (p.28 and 29)***

Given the analysis showing that flexible assets “will need to earn an increasing larger proportion of their revenue outside the wholesale market” under current market arrangements, our view is that reform of the wholesale market should be prioritised in order that system and flexibility value can be more accurately revealed. The latter could mean greater occurrence of volatile prices or scarcity pricing as we expect assets providing flexibility and peaking/ramping/renewables-following services to bid based on opportunity costs, taking account of their declining load factors, but we also expect competition to drive down these costs.

Efficient market design should allow exit of high carbon and inflexible assets no longer needed, with any exits raising the wholesale prices and load factors for remaining assets from the market. That said, it will be necessary to ensure an orderly, managed exit to prevent operability/reliability issues that could arise from sudden exit of plant still needed to provide adequacy or particular services, and location is likely to be important. This must be achieved in a cost-effective way, which may be best achieved by procuring services from select critical assets rather than through a market-wide mechanism. If the plant is uneconomic but is still needed by the system and must be supported with “out-of-market" subsidies, it should not be allowed to compete in the wholesale market in order to prevent market distortions and harming competition (e.g. as per best practice design for Strategic Reserves (EU Electricity Regulation 2019/943 Article 22)).

***Increasing system flexibility (excess generation) (p.30)***

For the challenge relating to addressing excess generation, the consultation document only mentions demand-side flexibility (p. 31). The magnitude of excess generation can also be linked to cost-inefficient overbuild, the risk of which can be mitigated through improved whole system planning and policy coordination (to strike the optimal ratio of weather-dependent renewables to flexibility), as well as more ambitious demand reduction (energy efficiency) policy (see our response to Q12).

***Managing Price Volatility (p.36)***

We agree that current high wholesale prices and consequent high inframarginal rents accruing to some parties require short-term intervention during the gas price crisis to protect consumers. While short-term actions are needed to protect consumers against price shocks or extremes, in the longer term it is important that wholesale market prices accurately reflect system value so that market participants can respond and innovate.

We therefore disagree with the framing of price volatility itself as a fundamental problem that needs a solution (unless it is caused by inefficient market design such as thresholds or cut off points resulting in cliff-edge change (e.g. the beginning and end of long settlement periods)).

Price volatility due to high or low availability of renewables is an important market arbitrage signal to incentivise the low carbon flexibility that is critical to achieving net zero. For many flexible assets, price volatility will enhance rather than reduce investor confidence and their response will smooth the volatility.

***Limited market signals for electricity demand reduction (p. 39)***

We disagree with the identification of limited market signals for electricity demand reduction via energy efficiency measures as an issue for consideration in electricity market reform. See our response to Q12.

***Additional future challenges not identified: risk of future price shocks and need for temporary mechanisms***

The recent experience of extremely high gas prices has placed a spotlight on our preparedness to price shocks and the need for temporary measures when they occur. Lessons can also be learned from other jurisdictions: Texas market failure in cold weather, February 2021; Australia suspending spot market, June 2022.

Recent high gas prices have given rise to excessive inframarginal rent. It is not so much the very high prices that is an issue (that could be witnessed by the minute / hour / day in price volatility or scarcity prices reflecting system conditions) but the sustained duration of these very high prices over weeks and months due to a war and the closure of major gas pipelines. In future we should be prepared for more price shocks, particularly given the changing climate, and changing power system.

Temporary price shocks due to extreme / exceptional events need temporary mechanisms, although well-designed markets and policies for net zero could increase consumers' resilience to price shocks. Such temporary mechanisms and backstops need to be transparent and well-designed, setting out clearly to the market the conditions under which the mechanisms are triggered and terminated. Market design reforms for a net zero future should incorporate such mechanisms - for example see here.

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

☒ Yes ☐ No ☐ Don't know ☐ No opinion

*Please expand on your response here:*
As set out in our ESO Net Zero Market Reform Phase 2 and Phase 3 reports, we agree that the current market arrangements are not fit for purpose for delivering a 2035 zero-carbon electricity system. We believe future electricity market design should seek to address the following issues:

- The single national wholesale price is inappropriate in a high renewables system. Locationally accurate wholesale pricing is needed to incentivise appropriate behaviours, on both the supply and demand-side, in operational and long-run timescales.
- The current self-dispatch mechanism is proving inefficient for optimising high volumes of weather-dependent generation. We believe the combination of nodal pricing and central dispatch with self-commitment is the optimal way to coordinate supply and demand; however, even without locational wholesale pricing, centralised wholesale market clearing and dispatch may also be preferable to the status quo. (See also Q22 and Q68).
- Lack of coordination and continued asymmetry of policy and financial de-risking support across supply- and demand-side will lead to a sub-optimal power mix, with resultant renewables curtailment and increasing levels of price cannibalisation resulting in unnecessarily high costs for consumers. There also exists inconsistency in the magnitude and targeting of signals through policy and markets, and policy sometimes inappropriately shields key assets from system value signals or distorts signals. Reformed and additional policy instruments are required to support investment in the electricity system at the required (and unprecedented) scale and pace, to achieve a balanced, cost-efficient portfolio of weather-dependent and flexible resources.

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## Chapter 3: Our Approach

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

☐ Yes ☒ No ☐ Don't know ☐ No opinion

*Please expand on your response here:*
**REMA objectives should be included among the assessment criteria**

We note and support the principle that BEIS' assessment criteria should facilitate differentiation between options; however, we disagree with the omission of the REMA objectives (decarbonisation, system security and cost-effectiveness) from the assessment criteria. The options can be distinguished based on how far they contribute to the achievement of these objectives. Omitting them from the criteria risks distorting the assessment by de-prioritising the most important outcomes or lack of transparency in decision-making.

As stated in Q1, we additionally believe that BEIS should include Consumer Fairness in its assessment criteria.

**Include separate assessment criteria for 'Whole System' and 'Full-Chain Flexibility'**

We believe it is important to disaggregate the whole system flexibility assessment criteria into separate criteria for full-chain flexibility (cross-voltage, all electricity resources (supply/demand)) and whole system (cross-energy vector) flexibility. Aggregating these two considerations into a single criterion risks under-representing their overall importance and risks reducing the transparency of their assessment, given that options could have been assessed favourably against one and negatively against the other.

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

☒ Yes ☐ No ☐ Don't know ☐ No opinion

*Please expand on your response here:*
We broadly agree with the identification of the main categories of options for reform. The consultation has not identified the greatest priorities for reform, nor the sequence in which they should be addressed. We discuss in Q7 the sequence ESO adopted for assessing market design categories in Net Zero Market Reform.

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

*Please provide your response here:*
A logical sequencing to the construction and assessment of packages is important to reduce the potential for unintended interactions between market design interventions. Without a logical sequencing approach, there may also be too many interactions between market design elements in the overall package to enable a transparent options shortlisting process.

The requirements for policy interventions to support investment are the product of missing signals provided in operational timescales. Resolving deficiencies in the wholesale market design should therefore be a prerequisite to addressing the degree and nature of further investment interventions. Therefore, the market design options identified under the wholesale market category in the consultation document should be assessed before the other options.

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## Chapter 4: Cross-cutting questions

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

☐ Yes ☒ No ☐ Don't know ☐ No opinion

*Please expand on your response here:*
We broadly agree with the key cross-cutting questions identified when considering options for electricity market reform. We differ on the following points:

**Marginal pricing is natural to commodities meaning interventions to avoid marginal pricing in electricity markets would require significant government intervention:**

The role of marginal pricing in the GB electricity market is more complex than the consultation description implies. The natural price formation process of uniform commodities, such as electricity, means that they tend to price at the margin since producers of the same good will seek to charge the cost of the most expensive producer. At the same time, forward-trading and contracting mechanisms such as PPAs and CfDs mean that wholesale market prices consist of multiple transactions that are distinct from the cost of the marginal plant at the point of delivery.

The statement that 'the marginal price model has been adopted by the majority of liberalised electricity markets' implies a conscious policy or design decision that ignores the decentralised nature of commodity pricing. In reality, measures to 'move away from marginal pricing' are likely to involve significant complexity and central government intervention.

We discuss in Q14 the unintended consequences that may arise from interventions that seek to split the wholesale electricity market by technology type and provide possible alternative mechanisms that would address the link between gas and electricity prices at less risk to consumers.

**Minimising financing costs may not ensure overall system costs are reduced:**

We would suggest revising the cross-cutting issue of "minimising financing cost and maximising operational signals". Whilst it is important to optimise financing costs, this is different to minimisation. Efficient risk allocation may result in financing costs that are greater than the minimum possible but still reduce overall system costs and therefore total costs to consumers. For example, by assuming more locational risk, the financing costs of generators may increase but the overall cost to consumers may decrease due to a corresponding greater reduction in congestion costs. The goal should therefore be to optimise whole system costs, rather than to minimise financing costs.

**Incentivising efficient whole system outcomes should be prominent as a cross-cutting issue:**

Electricity market arrangements that provide signals to incentivise efficient investment, operation, and transportation across energy vectors will be critical to achieving net zero at lowest cost whilst ensuring system security. We believe they warrant further explicit consideration in REMA.

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

☐ Yes ☒ No ☐ Don't know ☐ No opinion

*Please expand on your response here:*
We note the identified trade-off in the cross-cutting question on financing costs and operational

signals that "variable renewable assets are limited in their ability to respond to price signals, so there is a greater trade-off between financing costs and operational signals". As explained in detail in our response to Q11, we believe that the price responsiveness of variable renewable assets is greater than is commonly articulated. A detailed appreciation of the nature and level of responsiveness will be critical in considering the optimum balance in this trade-off.

On the question of more accurate price signals and the benefits for consumers, the consultation document identifies a trade-off between overall cost reductions from more accurate price signals and the risk of exposing consumers to higher prices which they cannot respond to. We do not believe that this is inevitable for all market reforms that introduce more accurate price signals, as astute market design can overcome this trade-off. For example, a trade-off between locational pricing cost reductions and distributional impacts could be avoided by (residential) demand-side prices being calculated using the temporal profile of the price signals only, with absolute prices adjusted to maintain equal average prices across all locations.

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

*Please provide your response here:*
Embedding locational signals in the wholesale price provides the most efficient short-run signals and facilitates cross-vector efficiency. It also provides accurate locational investment signals, though these could be strengthened through other means if considered appropriate. The response below discusses signals for efficient dispatch and then signals for efficient investment.

**Accurate signals for efficient dispatch:**

Locational signals that deliver efficient dispatch decisions must be:

a) Time-accurate: the signal must react dynamically as network constraints evolve with changing supply and demand
b) Locationally-granular: as far as possible, the signal should apply only to assets that can alleviate the constraint

**1) Locational wholesale markets provide most locationally and temporally accurate dispatch signals:**

Dynamic locational signals can be achieved by locational wholesale markets (nodal or zonal pricing), local constraint markets, and via the Balancing Mechanism (BM). Of these options, locational wholesale pricing offers most efficiency since:

- The locational value of electricity updates dynamically for each settlement period, accounting for changing market conditions
- Participants do not incur opportunity costs from lost wholesale market revenue, for addressing congestion, as they would under the current BM design
- It can be applied across the whole market, facilitating ‘implicit’ response from flexible assets, whereas ancillary and balancing services require ‘explicit’ participation, increasing the administrative burden for participants due to requirements such as baselining

Crucially, interconnector flows are determined by relative wholesale prices, so only locational wholesale pricing could facilitate efficient import and export flows that align with whole system needs.

Implementing nodal pricing down to GSP would most effectively reveal locational value on the transmission system. (See Q18 for distribution level constraints). To the extent that zonal boundaries accurately reflect network constraint boundaries, zonal pricing would also drive efficient locational signals for investment and dispatch across the transmission system.

**2) The Balancing Mechanism does not provide a clear locational signal and has limited scope:**

We believe the BM is limited as a forward-looking locational signal, since:

- The mechanism procures multiple products, meaning that an asset may be accepted for additional reasons besides resolving a constraint, dampening the clarity of the price signal.
- The BM is intended as a residual market and therefore only a subset of available generation and demand participates. When discussing whether constraint costs could be forecasted, the BSUoS taskforce final report noted that while high wind and low demand correlated with constraint costs, 'this can only provide a small signal to some specific users[1]'. While ESO is taking measures to widen access to the BM, making it market-wide would be equivalent to implementing central dispatch.

**3) Local constraint markets can send effective dispatch signals, but their limited scope may reduce their efficiency:**

- Where constraints can be resolved by assets over a wider area than the market covers, local markets may not provide the most efficient solution. For example, a constraint at the Scottish B6 boundary could potentially be addressed by turning down generation or increasing demand anywhere north of the border.
- Local constraint markets are effectively ancillary services that require procurement decisions in advance of real-time, reducing wholesale market liquidity and creating opportunity costs for participating assets. We are aware that Australia, a jurisdiction with central dispatch, is considering co-optimisation of an ancillary market for constraints with its zonal energy market[2] and this approach may resolve the risk of participants incurring opportunity costs.

<u>**Accurate signals for efficient investment:**</u>

**1) Locational wholesale pricing would provide accurate signals for efficient investment. Alternative effective long-run signals cannot support actions in operational timeframes:**

Locational signals for efficient investment communicate where assets should site either:

a) To avoid or alleviate network constraints
b) To minimise whole system costs by reducing losses

Locational wholesale pricing provides strong and accurate investment signals: in areas 'behind constraints' nodal and zonal prices will be lower, incentivising supply-side assets to locate in front of the constraint and demand-side assets to locate behind the constraint. Nodal pricing efficiently accounts for losses, further encouraging supply to locate closer to demand.

[1] BSUoS taskforce 2019 final report; section 2.2.10
[2] The Modified Congestion Relief Market Model; 10th June 2022;

The presence of a local constraint market may incentivise assets to locate where they can participate in the market.

The Balancing Mechanism is ineffective as a long-run locational investment signal for the same reason as in operational timeframes (see above).

Other mechanisms, such as locational CfDs, a locational Capacity Market or upfront network connection charges, could potentially provide effective long-run investment signals. The TNUoS taskforce is additionally considering how TNUoS can be reformed to communicate cost-reflective locational signals. These mechanisms may be effective in driving investment in certain locations, although, as ex-ante charges, they could not provide efficient operational signals as the locational signal would be neither dynamic nor real-time. We think operational signals should be implemented in the first instance, since they apply on both a short- and long-run basis.

**Locational signals are needed in the wholesale energy price to deliver strong and accurate signals for cross-vector outcomes:**

Locational wholesale pricing would facilitate efficient cross-vector outcomes across electricity, gas and hydrogen. Under national pricing, there is no sustained signal for electrolysers converting electricity into hydrogen to capitalise where there is surplus generation. While the BM could be used to manage electrolyser consumption of curtailed energy, as discussed above, system actions in the BM are recognised to be too unpredictable to provide a useful forward-looking signal. Not exposing electrolysers to locationally cost-reflective wholesale prices may make the cost of green hydrogen production more expensive than is necessary.

Please provide any additional supporting evidence in .pdf or Microsoft Word format.

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

*Please provide your response here:*
The level of responsiveness to sharper locational signals must be considered separately for investment decisions and operational behaviour.

**1) Investment decisions:**

There is significant opportunity for locational signals to drive whole-system efficiencies over the next decade, particularly as, according to the FES 2022, a minimum of 203 GW of new generation and flexible capacity is connected between 2021 and 2050 to enable net zero. A full assessment of asset responsiveness to locational signals would need to assess each technology type individually, considering factors such as geographical and environmental factors and seabed leasing decisions. We are therefore pleased to see that BEIS is tendering for a ‘locational size of the prize’ project.

Centrally planned initiatives, such as strategic network build, are key enablers to renewables deployment over the coming decade. Taking a strategic planning approach and introducing sharper locational signals are not mutually exclusive. We believe market reform is needed alongside greater coordination between seabed leasing and network planning, and that the two initiatives can be coordinated and complementary. For example, seabed leasing rounds determine the options for offshore windfarm locations. We are therefore supportive of BEIS’ suggestion that the Offshore Transmission Network Review enduring regime could have seabed leasing processes that take account of electricity system considerations to a greater extent.

The comments below identify some areas we think the assessment could consider.

a) **Future capacity would be particularly responsive to locational signals:**

Many of the market participants who could be most responsive to sharper locational signals are not active in today's market. In our 2022 ESO Future Energy Scenarios report, we see up to 51 GW of electricity storage across our scenarios in 2050, compared to 4 GW in 2021; 54 GW of demand-side response, compared to 6 GW today; and 55 GW of electrolysis from close to zero today. Electrolysis projects, whose cost base and hence profitability would be highly sensitive to power prices, would have a very strong incentive to site in locations where low-cost electricity is most frequently abundant. A similar dynamic applies to any energy-intensive industries, including many that are currently not active in GB partly due to prohibitively high energy prices.

b) **Locational signals are a significant component in siting decisions at investment stage. The marginal plant will not be built where the value they add to the system is less than the cost to build. Accurate locational signals may make other plant newly investable:**

Responsiveness to locational investment signals will depend on several factors driving the sensitivity of the overall business case to the signal. These currently include the proportion of the overall revenue derived directly from the energy price and the proportion of the cost base dictated by locational cost such as TNUoS.

For example, for an offshore development project that comfortably exceeds its minimum rate of return, the locational signal may not be pivotal in whether the project goes ahead. This is an efficient outcome if the project costs are lower than projected revenues where the wholesale energy price accounts for locational value.

If the same project now faces higher costs, for example due to a requirement for mitigation measures following an environmental survey, the project may now be less profitable such that the prevailing locational signal is now pivotal in whether it goes ahead. The level of price responsiveness is the same in both scenarios but was only revealed in the latter. This dynamic would create the opposite response where cost-reflective locational signals result in higher wholesale energy prices, since, all things being equal, the higher revenue potential would make marginal projects investable in locations that are currently uneconomic.

It is also important to note that the net responsiveness of assets will be influenced by interactions with the design of other support mechanisms such as CfDs. If these incentive mechanisms inadvertently dilute or negate the locational price signals, the asset responsiveness may be blunted or potentially removed entirely. It is therefore vital to ensure that operational signals are coordinated with support mechanisms in this respect. Provided that CfD design under nodal or zonal pricing supports locational signals, we would expect to see the trade-off between factors such as regional wholesale price, load factor and other build costs reflected in the strike prices submitted by renewables assets at CfD auctions, thereby influencing investment decisions.

c) **Growing evidence of corporate responsiveness to locational signals**

While siting decisions will be informed by multiple factors, in a similar way to supply-side assets, we note the growing appetite from corporate consumers to locate where they can evidence their energy consumption is as 'clean' as possible. For example, Google's "Policy Roadmap for 24/7 Carbon-Free Energy", highlights the importance of more granular price signals in empowering consumers to shift the time, and in some cases the location, of their energy consumption to align with carbon-free generation. Google has developed "a first-of-its-kind system that can shift flexible computing tasks at its data centres across time and space to better align with lower-carbon hours on the grid". The Google example indicates the large potential for greater demand-side responsiveness to supporting decarbonisation. Locational wholesale pricing would provide the most effective data foundation for such initiatives.

**2) Operational responsiveness**

Flexible assets such as batteries and industrial demand-side response providers would be particularly responsive to locational operational signals. The response below identifies several market participants who may also realise significant locational value in operational timescales.

a) **Residential consumers:** We believe that consumers will have increasing opportunity to respond to dynamic price signals in operational timeframes via their suppliers, with smart meters and demand response contracts or tariffs. The option to expose consumers to an accurate within-day price profile, whilst ensuring average tariff parity nationally, could unlock mass residential flexibility while addressing concerns over distributional impacts. Our response to Q17 discusses in more detail the options for consumer exposure to regional variation in locational prices.
b) **Interconnectors**. Because interconnector flows are determined by relative wholesale prices, their exposure to locational signals under nodal or zonal pricing could substantially impact how both existing and future interconnectors flow.
c) **Intermittent renewable generators:**
    a. Under locational wholesale pricing, low wholesale prices disincentivise assets from dispatching where they would cause a constraint, thereby improving operational outcomes. Local constraint markets and Balancing Mechanism instructions also incentivise this action but with less cost-efficiency due to these markets' limited participation and since the national wholesale market would continue to clear without regard to system constraints.
    b. An important consideration is how support mechanisms such as CfDs interact with locational signals in operational timescales. As discussed in Q66, the current CfD design impacts intraday markets and the Balancing Mechanism by incentivising artificially low bids. Ensuring CfD design coheres with the objectives of operational locational signals will be key to facilitating efficient dispatch.
    c. Markets with LMP where renewables are exposed to locational value see increased volumes of co-location of storage assets to balance low local prices. Another option is for developers to pursue portfolios that are 'physically hedged' – for example investing in storage assets which would have a complimentary revenue profile to intermittent renewables. This response is economically efficient and would improve overall system operability outcomes consistent with locational requirements.
d) **Green hydrogen electrolysers:** The production of green hydrogen from curtailed wind presents a significant opportunity for cross-vector efficiency in GB's future energy system. As discussed in Q10, the BM can be used in operational timeframes to coordinate wind curtailment with electrolyser demand, but we do not believe it is not a reliable forward-looking signal. Locational wholesale pricing and, to a lesser extent, local constraint markets are preferable for facilitating electrolyser responsiveness.

Please provide any additional supporting evidence in .pdf or Microsoft Word format.

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

*Please provide your response here:*
We disagree with the suggestion in the consultation document that the main barrier to permanent demand reduction lies in the electricity market design itself:

- In principle, enduring demand reduction is rewarded in the existing market design to some extent via avoided wholesale energy (average prices) as well as network, policy and balancing costs. The accuracy of the quantum of the reward is, however, currently distorted by:
    1) the lack of accurate locational differential in the avoided energy costs; and
    2) how legacy policy costs are recovered from electricity and gas tariffs, with higher cost burden on electricity despite being less carbon-intensive than gas.
- We are aware of successful attempts to renumerate energy efficiency through power market design, such as centralised Capacity Markets. As outlined in our response to Q54, however, we believe that any capacity renumeration mechanism should align more closely with the real-time price signals of the wholesale market to more strongly incentivise response from any resources able to mitigate system stress wherever and whenever it occurs. This implies moving away from availability payments towards the use of financial instruments.
- Any additional power market mechanism specifically designed to further incentivise permanent demand reduction could risk being duplicative and distortive, potentially introducing perverse incentives to delay investment until administrative baselining start dates. Inevitable problems with baselining may also lead to payments for phantom reductions in energy usage, the cost of which will ultimately be socialised across consumers.

We believe the ambition of policy to incentivise greater levels of energy efficiency needs to be significantly elevated. As we highlighted in our 2022 Future Energy Scenarios document, improving energy efficiency is a no-regrets policy solution that can provide immediate benefits in terms of both affordability and energy security, while also facilitating more enduring decarbonisation. However, we believe it is policy, not market design, that can address the key barriers to unlocking energy efficiency, such as agency (often those responsible for the investment, e.g. landlords, are not direct beneficiaries) and access to low-cost financing.

## Chapter 5: A net zero wholesale market

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

☒ Yes ☐ No ☐ Don't know ☐ No opinion

*Please expand on your response here:*
We believe all credible options for wholesale market reform are being considered.

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

☐ Yes ☒ No ☐ Don't know ☐ No opinion

*Please expand on your response here:*
Splitting the market is primarily proposed as a solution to:

i. Price cannibalisation (and consequent price volatility): this occurs for renewable assets when their output correlates with low price periods, lowering their average captured price (with fluctuations between these low prices and high prices when renewable output is low)
ii. Decoupling electricity prices from gas prices (or expensive price-setting resources): there are concerns that high wholesale gas prices are setting wholesale electricity prices most of the time, resulting in excessive inframarginal rent paid by consumers to renewable generators

**Any change in market design that causes a structural divergence in fundamental price formation between markets (including neighbouring markets) must be considered with caution due to impacts on market-wide dynamics and incentives, as well as the risk of unintended consequences.**

We are concerned that moving away from marginal pricing to split the wholesale market by technology type risks unintended consequences. These could include:

- Inaccurate signals of system value and limited price exposure of some parties could weaken incentives to help reduce system costs, driving increased balancing costs
- Perverse incentives for cross-border trading if GB trading price does not accurately reflect system value
- Reduced competition and liquidity in balancing and ancillary services markets, where intermittent renewable generation would not be incentivised to participate

While there are no examples of market splitting anywhere in the world that we can learn from, the recent intervention in Iberia is a good indication of how intervening in electricity price formation can lead to unintended consequences. In that case, the move to decouple electricity and gas prices by capping the cost of gas for electricity generation has incentivised a marked increase in gas consumption for generation (up by ~40%) and greater exports to neighbouring countries. This potential 'leakage' of subsidised gas generation via exports could be significantly worse if the measure was applied to the GB market due to greater levels of interconnection.

**Price cannibalisation forecasts are an indicator that there is market disequilibrium. Facilitating flexibility addresses the root cause, including incentivising response from flexible assets to low-price periods via accurate price signals and efficient geographic siting of assets influenced by accurate locational signals.**

Alternatives that could effectively address the challenges but with reduced risk of unintended consequences include:

- Expanded use of CfDs, but with some price exposure built into design, would decouple renewables from more expensive price-setting resources (requiring generators to pay back to consumers when revenues are above a cap) while incentivising renewable generators to respond to market prices that would reduce system costs. Some price exposure would also reduce price cannibalisation as the current CfD design encourages generators to dispatch at the same time and when prices are below their marginal costs.
- Nodal pricing (and zonal pricing to a lesser degree) would reduce inframarginal rent, as more expensive dispatchable / backup resources would not necessarily set the price across the whole of GB. Locational pricing would also mitigate price cannibalisation as generators exposed to locational prices would site more efficiently to maximise their revenues.
- Measures to unlock full-chain flexibility would address price cannibalisation by putting upward pressure on low prices, enabling renewables to recover their costs. These measures would also put downward pressure on high prices, reducing inframarginal rent and bills for all consumers, not just for those responding to prices.
- Improving energy efficiency is a no-regrets policy solution that can provide immediate benefits in terms of both affordability and energy security while also facilitating more enduring decarbonisation (see FES 2022). By impacting price formation, demand reduction reduces inframarginal rent and bills for all consumers, not just for those implementing energy efficiency improvements.

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

*Please provide your response here:*
As explained in our response to the previous question, we do not agree that a split markets model or green power pool are justified on the grounds of price cannibalisation and price volatility. We are not convinced that the fundamental disadvantages and risks of moving away from a unified market, outlined in the consultation document, can be overcome via detailed design choices. That said, there exist many unanswered questions concerning these new concepts that could be addressed by the authors/proponents as they further experiment and develop the designs through research projects.

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

☒ Yes ☐ No ☐ Don't know ☐ No opinion

*Please expand on your response here:*
Both options should be taken forward for further consideration. Locational granularity in the wholesale price is critical to achieving net zero at lowest cost whilst ensuring system security.

The locational value of electricity must be embedded within the energy price itself to achieve both efficient cross-vector outcomes and full demand-side market participation. As long as the real-time wholesale price cannot communicate the locational value of energy, both generation and demand-side assets and participants in markets for other energy vectors will respond to inaccurate signals, leading to inefficient system outcomes and ultimately higher costs to consumers.

Nodal pricing is the most efficient form of locational wholesale prices, as nodal prices most accurately reflect the full marginal cost of meeting demand at a certain time and location. Zonal pricing is the best of the alternative options presented in the REMA consultation for the reform of locational signals.

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

*Please provide your response here:*
The following section identifies ways that the challenges to nodal and zonal pricing in GB can be addressed.

**<u>Nodal pricing:</u>**

**1) Multiple options open to policymakers in how consumers experience regional wholesale price variation**

We note that very few jurisdictions expose residential consumers to their nodal price, and instead choose zonal pricing and/or to differentiate by type of demand to mitigate consumer distributional concerns.

We agree that a weighted average zonal price or "opt-in" pricing could effectively mitigate (to varying degrees) the distributional impact of nodal pricing on GB consumers. Exposure could also be limited to the supply side or be applied to specific demand segments such as I&C. Whilst this would reduce the total potential benefits (as the demand-side would not face the true locational signal and hence not be able to respond accordingly), we believe that nodal pricing could be justified due to more efficient supply side dispatch and siting alone, as it has been elsewhere.

Another option that warrants further investigation is to expose consumers to an accurate within-day nodal price profile that reflects local generation output through the day, without exposing the consumer to systemic locational differences in power prices. This could be achieved via the application of an adjustment factor to bring weighted average power prices in each area to a national average level. The adjustment factor would be negative in higher average nodal price areas and positive in lower average nodal price areas. This option potentially incentivises the demand-side to harness low carbon, low-cost energy when and where it is available or to reduce system costs, whilst avoiding major distributional impacts for domestic consumers.

**2) Assessment of liquidity under nodal or zonal pricing should account for the challenges in forward-contracting in highly decarbonised and flexible systems**

An assessment of reduced liquidity under locational pricing should account for the following considerations:

a) Liquidity in GB forwards-markets is already poor. We believe this is at least in part due to reduced supply-side incentives to trade forward as intermittent renewable generation increases. Predictable generation patterns facilitate forward-trading since both generators and load trust that output will meet demand. Selling forward exposes intermittent generators to the risk of high prices when they are not generating. Retailers wishing to trade forward with these parties incur higher prices to account for the added delivery uncertainty.
b) The single national price dilutes the benefits of liquidity by facilitating forward-contracting for energy in congested areas that cannot be delivered and is therefore not socially useful. The cost of re-dispatching with available generation is reflected in BSUoS costs.
c) We see liquidity in operational timescales being increasingly important as intermittent renewable generation and demand-side flexibility capacity increases. A central dispatch wholesale market would increase liquidity (and therefore price transparency) in operational timescales. Co-optimisation of energy and ancillary services would pool available flexible capacity.
d) Under nodal or zonal pricing, the pool of participants directly exposed to each locational price is smaller, reducing the number of parties with a complementary risk profile who are therefore willing to forward-trade. It is notable, however, that other nodal markets such as PJM, New Zealand and ERCOT, Texas, do not appear to have liquidity issues in either forwards markets or closer to delivery. (Bid-Ask Spreads for 2022 PJM 3-months ahead peak load contract is 1% and for ERCOT is 4%. New Zealand 4 months ahead baseload is 4%, vs GB 4-month baseload was 1.5% in 2020 and 2.9% in 2022.)
e) As noted in the consultation document, trading hubs are widely used in nodal markets to facilitate market liquidity and trading simplicity. We believe these would also be appropriate in a GB context and have not seen evidence to suggest implementation costs are prohibitive against the benefits they offer.

**3) Nodal pricing would reveal underlying system volatility, enabling market to address root causes of high balancing costs**

The variability of locational prices caused by network congestion exists in the current market, but as system costs in the Balancing Mechanism. Under code reform CMP308, from April 2023 this cost will be borne by consumers as a pass-through cost in BSUoS. Generators also incur risk from the unpredictability of BM revenues. We note that the ESO-led Balancing Services Charges Taskforce previously put forward locational wholesale pricing as a viable way to address volatile balancing costs[3].

Under current arrangements, consumers bear the downside risk of the true locational price rising above the national price and having to pay to constrain generators on, while receiving none of the upside risk when the true locational price is below the national price.

By making locational value clear to the wholesale market, nodal pricing would allow for market participants to address network congestion transparently and at reduced consumer cost. The reduction in cost is due to:

- The action being facilitated by the wholesale market clearing process, rather than as a redispatch action following gate closure.
- The locational price would be forecastable in a way that Balancing Mechanism prices for resolving thermal constraints are currently deemed not to be (see the second BSUoS taskforce final report). This forecastability reduces risk for all participants exposed to system actions in the Balancing Mechanism (i.e. payers for BSUoS charges, and BM participants).

**4) Implementation of nodal pricing would be substantial and complex, but international experience suggests benefits significantly outweigh costs**

We agree that implementing nodal pricing would entail ESO implementing new IT systems to facilitate nodal market clearing and dispatch. Market participants would also need to modify or renew their trading infrastructure to participate in a reformed market.

ESO is ready to support BEIS in understanding the cost of a nodal implementation to itself and the industry. We note that in previous international nodal implementations, the costs incurred by the system operator were quickly outweighed by the system benefits and we have not seen any evidence to suggest this would be different in a GB context.

Whilst ESO is already improving its capabilities, via programmes such as the ESO Balancing Programme, we expect that additional investment will be required throughout this decade to develop new capabilities to meet the operational challenges of GB's emerging electricity system. The costs of implementing nodal pricing must therefore be assessed against a realistic baseline of what will be needed to operate GB's system without this reform.

**5) Investment hiatus can be avoided via well-designed transitional measures and presence of appropriate support mechanisms**

We agree that careful management of a transition to nodal pricing would be required to minimise participant disruption and ensure sustained investment. As set out in the NZMR Phase 3 report, evidence from other markets internationally suggests that renewables investment can continue to grow prior to, during and following nodal implementation, though it is clear that decarbonisation investment policies play a crucial role to complement the price signals of the wholesale market to secure investors' confidence. Importantly, the transitional arrangements during implementation and choice of accompanying support mechanisms (for example CfD design) will be as critical in securing ongoing investment as nodal design and implementation itself.

**6) Compatibility of nodal market design with European zonal markets to ensure continued interconnector operation**

[3] Balancing Services Charges taskforce 2019 final report; p.5:

We are assessing the potential impact to cross-border trading of moving to nodal or zonal designs. A key issue with current arrangements is that in certain circumstances interconnectors are being dispatched in a way that is not aligned with system needs (see ESO NZMR Phase 3 report).

Moving to nodal or zonal pricing would allow trading parties on interconnectors to capture locational value in a way that is not possible under current market structures.

Our current view is that moving to central dispatch (rather than the introduction of nodal or zonal pricing) would constitute the larger regulatory change compared with status quo arrangements; however, we note that GB shares two interconnectors with the centrally dispatched Irish market, so do not believe that the central dispatch mechanism per se would prevent effective cross-border trading.

**Zonal pricing:**

**1) Market manipulation**

We agree that "inc-dec gaming" may be a risk under zonal markets, although the same incentives and market structure exist in the current GB design. We believe the benefits from reduced congestion costs under zonal pricing would likely outweigh any consumer costs from this type of strategic bidding versus the status quo design.

**2) Redrawing boundaries**

The process to redraw zones to reflect changes in key transmission constraint boundaries could be adapted to mitigate perceived regulatory risk. For example, a transparent review process could be established on implementation, with clear rules governing when and how boundaries must be redrawn, analogous to the TNUoS rezoning rules in CUSC or the European Bidding Zone Review. This would reduce the risk of unpredictable regulatory intervention and the potential for lobbying activity of market participants with vested interests to influence rezoning outcomes.

## 18. Could nodal pricing be implemented at a distribution level?

☐ Yes ☐ No ☐ Don't know ☒ No opinion

*Please expand on your response here:*
**Feasibility of implementing nodal pricing accurately in a single transmission and distribution optimisation is dependent on computing power and is not currently practical:**

Our early understanding from international case studies is that nodal pricing across both distribution and transmission constraints is currently not computationally feasible without excessive simplification of network topology. While theoretically possible (provided computational power continues to increase), we do not consider it practically feasible to implement nodal pricing over both transmission and distribution networks in the short- to medium-term.

**Priority should be facilitation of DSO-markets and ESO<>DSO coordination:**

As discussed in Q65, DSO flexibility markets will be critical for helping to avoid distribution network constraints and other services (e.g. accelerated connections). ESO is working with distribution networks to ensure our services are coordinated and to improve visibility of each other's networks and market operations.

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

☒ Yes ☐ No ☐ Don't know ☐ No opinion

*Please expand on your response here:*
We agree that distribution-led approaches warrant further investigation to explore how they could be aligned with transmission-level markets and deliver more optimal cross-vector outcomes.

**Energy balancing is most efficiently managed on a system-wide rather than local basis:**

ESO's Future Energy Scenarios 2022 project that, under all scenarios in 2030, c.70% of generation capacity will be connected at transmission level voltages, suggesting that energy balancing first at distribution level would create inefficiencies from a whole-system perspective. We therefore do not support further consideration of the introduction of "local imbalance pricing" in which the network is divided into local zones and suppliers face charge for imbalances in constrained locations. This would effectively create a de-facto zonal electricity wholesale market, since suppliers would be hedging against the risk of local imbalances in their wholesale trading activity, introducing serious market distortions, and lacking the transparency and wider benefits of a real zonal or nodal wholesale market that has a centralised redispatch process.

**Substantial value can be realised by DSO flexibility markets, and ESO is working in close collaboration with DSO colleagues to ensure these are coordinated with transmission system operations:**

The increase in electricity demand and flexible capacity at distribution level is already leading to significant congestion on distribution networks. Markets that incentivise demand-side shifting to help avoid or reduce distribution network congestion therefore offer substantial consumer value. As discussed in Q18 above, we believe continued growth of DSO markets for network flexibility is necessary to address distribution-network constraints and accelerate connections at that voltage. We discuss in Q65 what measures ESO is taking to ensure optimal inter-voltage coordination.

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

☐ Yes ☒ No ☐ Don't know ☐ No opinion

*Please expand on your response here:*
Our current assessment is that we do not believe any alternative credible approaches to developing local markets have been excluded from consideration in the consultation document.

## 21. Do you agree that we should continue to consider reforms that move away from marginal pricing?

☐ Yes ☒ No ☐ Don't know ☐ No opinion

*Please expand on your response here:*
We do not believe that reforms that move away from marginal pricing (i.e. a wholesale market based on pay as bid rather than pay as clear), warrant further investigation and agree with the analysis that is in line with considerable international literature on the topic (for example, see here). As outlined in the consultation document, marginal pricing is integral to the provision of effective

investment and operation signals via the wholesale market. We agree that a pay-as-bid regime would substantially reduce the incentive for flexibility and its introduction would necessitate further inefficient policy interventions, increasing the overall cost to consumers.

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

☒ Yes ☐ No ☐ Don't know ☐ No opinion

*Please expand on your response here:*
We agree that BEIS should consider amending the parameters of current arrangements. The following section outlines some considerations for future assessment of dispatch, settlement and gate closure. We note that, following on from the Balancing Market Review, ESO is looking at appropriate changes to the parameters of current balancing market arrangements for short and long timeframes. Similarly, through our enhanced Balancing Capability programme, we are developing new ways to schedule and dispatch Balancing Mechanism providers.

**Dispatch:**

1) **Centralised versus self-dispatch terminology can be misleading with regard to extent of system operator intervention**

It is helpful to break down considerations of dispatch mechanisms into:

a) Scheduling: the plan of which resources will be deployed to match supply and demand and to cover relevant contingencies. Scheduling usually takes place between 36 and 12 hours before delivery.
b) Unit commitment: the process of deciding which and when scheduled assets should be instructed to prepare to dispatch.
c) Real-time dispatch: the issuing of real-time instructions to assets to turn on/up or turn down/off to balance supply and demand

The 'central dispatch' versus 'self-dispatch' distinction can be misleading in implying that the role of the system operator (SO) in centrally dispatched markets is inherently greater than in self-dispatch markets.

In the current GB market, scheduling and unit commitment prior to gate closure is theoretically done by market participants, while ESO conducts real-time dispatch in the Balancing Mechanism. In practice, ESO frequently commits assets before gate closure, so that they warm up to ensure there is sufficient capability near real-time.

Markets that have central dispatch with self-commitment, such as US nodal markets, allow assets to self-schedule and prepare to dispatch up to real-time, without system operator intervention. Further, the day-ahead market clearing process determines asset schedules by clearing bid-in demand against offered-in supply. Therefore, while the SO is counterparty to trades, at day-ahead stage it does not determine overall procurement levels. In this way it resembles power-exchange trading in self-dispatch markets.

2) **Important factors for determining the efficiency of real-time dispatch we think BEIS should consider in its assessment include:**

a) The quality of wholesale price formation:

Wholesale market trading in forward and spot markets establishes asset schedules prior to unit commitment. A key determinant of whether the SO intervenes to maintain system security is whether the wholesale market clearing process accounts for the physical constraints of the electricity grid. The GB spot markets (day-ahead and intraday auctions) do not account for system constraints, in particular network congestion. With the growth of offshore wind and distribution-connected generation, network congestion is now a key determinant of whether electricity can be dispatched. The wholesale market outcome is therefore not predictive of real-time dispatch, creating difficulties in forecasting balancing market outcomes and increased financial risk to market participants (see also Q62).

In contrast, nodal markets with a financially binding day-ahead market and real-time spot market are better structured to reduce balancing costs: since both the day-ahead and real-time market are cleared accounting for network capacity, and since they trade the same products, high day-ahead prices at specific nodes or hubs are effective indicators of where there is value to be traded at real-time.

b) Bidding formats:

Centralised and self-dispatch markets take different approaches to the information contained in bids and offers used to clear the wholesale market. The GB wholesale market currently uses 'simple' bids that specify the price and volume for a given time. Trading parties can submit a single bid to cover multiple assets. Prior to gate closure, they inform ESO what energy the total portfolio will produce or consume for that settlement period.

Centrally dispatched markets clear on a unit rather than a portfolio basis, and use 'complex' bid formats, that aim to reflect the true cost and constraint parameters of an asset, such as the time it takes to warm up. The SO uses this information, aiming to dispatch the most efficient combination of assets. (Markets with central dispatch and self-commitment allow assets to choose whether to submit a simple or complex bid, although tend to incentivise complex bids on the basis that it facilitates more efficient dispatch).

There is significant debate around which of complex or simple bidding produces the most efficient outcome across the system, and this is a topic we are assessing both in NZMR and as part of the BM review. In general, as system operator, we see growing challenges in viewing assets on a portfolio basis if they are spread over multiple locations. For example, a wind farm may be generating less than forecast, requiring ESO to deploy reserve capacity, but the trading position of its wider portfolio is balanced. Introducing complex bids may help to provide greater asset level visibility prior to gate closure, facilitating more efficient balancing outcomes.

c) Data transparency, accuracy, and availability:

Ensuring both the SO and market participants have accurate and timely visibility of market conditions will facilitate more efficient dispatch decisions. For example, if ESO under-estimates demand, it must procure more energy in balancing timeframes, likely at a higher price than would have been available pre-gate closure since there are a reduced set of resources available. Similarly, if a market participant submits inaccurate Initial or Final Physical Notifications, ESO will have a misleading view of supply and demand for that settlement period and may need to take more balancing actions. We suggest that BEIS explore whether provision of operational information between ESO and market participants can be improved to facilitate more efficient dispatch.

**3) Characteristics of future GB system are likely to require more centralised dispatch**

We believe there are several aspects of GB's emerging electricity market that mean more centralised scheduling and unit commitment decisions may improve on current arrangements. As part of our NZMR Phase 4 assessment we are considering whether central dispatch without locational energy pricing would be desirable versus the status quo.

a) Large swings in generation output limit self-dispatch efficiency:

The concentration of renewables in certain locations and variability of interconnector flows is leading to large swings in supply and demand in operational timescales. Requiring market participants to self-balance prior to gate closure in this context is likely to be less efficient than pooling asset liquidity in a centralised wholesale market.

b) Need to optimise 'shiftable' flexibility capacity around forecast system needs

The value of flexibility in shifting consumption from one period to another relies on knowing when energy is more useful to the system over multiple hours or even days. While market participants can take effective self-interested decisions, by virtue of its role, ESO has greatest visibility of forward-looking system requirements. ESO may therefore be best placed to determine whether a flexible resource should dispatch immediately or whether it could provide more value dispatching at a later stage.

**Settlement:**

We agree that BEIS should continue to look at changes to settlement, including changes to settlement period. As supply and demand assets become capable of responding more quickly to price signals, settlement periods with relatively large step changes will lead to increased challenges managing frequency and stability, leading to increased requirements for fast-acting reserve and frequency response. While other interim measures are available, such as limits on asset ramp rates, shorter settlement periods could most efficiently address the root issue.

Increased temporal granularity of the wholesale market would also provide greater and more accurate signals for flexible assets. It would help to illuminate where faster-acting assets provide added system value versus flexible but slower-acting assets.

**Gate closure:**

We agree that BEIS should continue to consider changes to gate closure. We note the appropriate gate closure time will be highly contingent on wholesale market design and dispatch mechanism. Without locational wholesale pricing, reducing the time between gate closure and delivery may impact ESO redispatch efficiency but increasing the time may bring dispatch benefits.

## 23. Are there any other changes to current wholesale market design and the Balancing Mechanism we should consider?

☐ Yes ☒ No ☐ Don't know ☐ No opinion

*Please expand on your response here:*
Our current assessment is that all credible changes to wholesale market design and the Balancing Mechanism have been included for consideration in the consultation document.

nationalgridESO

## Chapter 6: Mass low carbon power

### 24. Are we considering all the credible options for reform in the mass low carbon power chapter?

☒ Yes ☐ No ☐ Don't know ☐ No opinion

*Please expand on your response here:*
We believe that the consultation document sets out all the broad categories of options for reform in the mass low carbon power chapter, excluding those designed to incentivise investment in first-of-a-kind (FOAK) assets.

To ensure that low carbon power reforms are successful in driving the right carbon outcomes for the GB economy, and that the power sector decarbonises by 2035, we would emphasise the need to consider reforms in the context of a whole-economy carbon policy. More specifically for the power sector, a carbon emissions reduction strategy may be needed to track progress to the 2035 decarbonisation objective and identify if / when further interventions may be necessary.

More robust accounting of carbon emissions across the power sector through Monitoring, Reporting and Verification (MRV), and making the carbon intensity of electricity by time and location visible to consumers, would be helpful to ensuring the accurate matching of flexible demand to low carbon electricity through the wholesale and retail markets to unlock cost-effective carbon emissions reductions.

Tracking carbon to the consumer level could facilitate voluntary action through consumer contracts/tariffs to match flexible demand to low carbon power. This could mobilise more demand response as carbon intensity of the power mix does not always align with prices and some consumers are more motivated by carbon emissions reduction than price. More granular carbon data could also provide the basis for regulation later, if needed (e.g. through a supplier obligation).

Nodal pricing implemented with central dispatch could give greater visibility of the carbon intensity of the power mix by location that could influence siting of energy-intensive companies trying to reduce their electrical carbon footprint in granular timescales.

### 25. How could electricity markets better value the low carbon and wider system benefits of small-scale, distributed renewables?

*Please provide your response here:*
**Sharpening temporal and locational price signals.**

We agree with the rationale in the consultation document that the reforms proposed in the wholesale chapter that sharpen temporal and locational price signals would help drive deployment of smaller-scale assets. Such wholesale market reforms would more accurately reveal the wider system benefits of smaller-scale assets, enabling this to be captured in the export tariffs offered by suppliers.

**Levelling the playing field for transmission and distribution level renewables.**

The more that the full value of small-scale distributed assets is captured within wholesale prices themselves, the greater the playing field is levelled against transmission-level assets. Additionally, market design should aim to remove the barriers to entry for small-scale assets in CfDs and/or introducing separate government support schemes with equivalent incentives.

**Adopting a strategic approach to decarbonising the power sector**

See our response to Q24.

### 26. Do you agree that we should continue to consider supplier obligations?

☒ Yes ☐ No ☐ Don't know ☐ No opinion

*Please expand on your response here:*
We agree that further work should be undertaken to explore the potential to introduce supplier obligations in the future so long as the retail market conditions are conducive to effective and efficient implementation. An additional option that warrants further investigation is the potential to introduce a voluntary or hybrid scheme as a transitionary step towards a full supplier obligation applied to carbon, should it be needed later to achieve the 2035 decarbonisation objective, and delivering some of the benefits without the risks relating to complexity and deliverability. We will be analysing this further in our Net Zero Market Reform programme. See also our response to Q24 on adopting a strategic approach to reducing carbon emissions in the power sector.

Further work is required to establish:
- The extent to which the supplier landscape and retail market may need to change to make a supplier obligation effective at bringing forward low carbon investment
- How the financing and delivery risks of a supplier obligation could be overcome
- How the supplier obligation for carbon could efficiently interact with the UK ETS and CfDs
- How compliance for a supplier obligation for carbon would be cost-efficiently achieved through trading of verified credits/reductions

### 27. How would the supplier landscape need to change, if at all, to make a supplier obligation model effective at bringing forward low carbon investment?

*Please provide your response here:*
Please see our response to Q26.

### 28. How could the financing and delivery risks of a supplier obligation model be overcome?

*Please provide your response here:*
Please see our response to Q26.

### 29. Do you agree that we should continue to consider central contracts with payments based on output?

☒ Yes ☐ No ☐ Don't know ☐ No opinion

*Please expand on your response here:*
We agree that central contracts with payments based on output should continue to be considered at this stage though we believe reforms will be necessary to address several market and operability issues we have identified, as set out in our response to Q66.

## 30. Are the benefits of increased market exposure under central contracts with payment based on output likely to outweigh the potential increase in financing cost?

*Please provide your response here:*
Yes, we believe that the potential system benefits from price exposure are significant enough to warrant further investigation. See our response to Q31

## 31. Do you have any evidence on the relative balance between capital cost and likely balancing costs under different scenarios and support mechanisms?

*Please provide your response here:*
Whilst we acknowledge the interaction between increased price exposure under central contracts with payments based on output, and financing costs, we believe that it is not accurately represented as a simple bilateral trade off. The impact of increased price exposure is much broader than particular projects' financing costs and will strongly influence the wider effective functioning of the wholesale market itself. Greater exposure may not only reduce balancing costs, but could give rise to multiple other benefits including:

- Reduced liquidity issues facing suppliers, which in turn could help reduce consumer bills;
- Increased competition and innovation, particularly regarding system integration but also financial market innovation, driving down total system costs for consumers; and
- More balanced incentives for investment throughout the supply chain - involving not only generators and investors, but also trading intermediaries and innovators - resulting in greater system resilience and better outcomes for consumers.

ESO can model future balancing costs, while investors / developers can provide cost of capital estimates for particular projects (costs can vary widely across projects). However, it is very difficult to model the impact of a complex package of reforms on whole system and market dynamics. Analyses to date incorporate major simplifications and assumptions that can be challenged. There are also significant sensitivities to consider.

Many investors have confidence in CfDs but the impact that the current design is having on the system and markets is challenging for scaled-up investment as highlighted in our response to Q66. We believe that retaining CfDs in some form is key to retaining investor confidence and low cost of capital, especially if wider wholesale market reform is implemented. However, we believe that some CfD cost exposure may be necessary in a package of holistic reforms to cost-effectively achieve a decarbonised, operable, and reliable power system.

Please provide any additional evidence in .pdf or Microsoft Word format.

## 32. Do you agree we should continue to consider central contracts with payment decoupled from output?

☒ Yes ☐ No ☐ Don't know ☐ No opinion

*Please expand on your response here:*
We agree that central contracts with payment decoupled from output should continue to be considered at this stage. However, we share the concerns expressed in the consultation document about delivery challenges and how to reliably deem potential to generate. It is difficult to make accurate estimates, and this could mean under- or over-paying generators, while non-metered measurements are potentially less secure, and more open to gaming than metered measurements. Such contracts should not expose consumers to the risk of weather-related forecast error, which

should be retained by the generator who is best placed to manage it. Additionally, contracts would need to consider how to maintain incentives for efficient maintenance, with respect to both overall maintenance levels and scheduling of outages. These issues would need to be overcome in the design of such an option for it to be deemed preferable to an output-based renumeration mechanism.

### 33. How could a revenue cap be designed to ensure value for money whilst continuing to incentivise valuable behaviour?

*Please provide your response here:*
We are currently conducting analysis of various options for improving mass low carbon power incentives. This will include consideration of whether, and how, a revenue cap can be designed effectively to ensure value for money whilst continuing to incentivise valuable behaviour. We will continue to work closely with BEIS, sharing the findings of this work as soon as it is completed.

### 34. How could deemed generation be calculated accurately, and opportunities for gaming be limited?

*Please provide your response here:*
In theory, deemed generation for variable renewable sources could be calculated using equipment manufacturers' power curves, which demonstrate the relationship between weather resource and power output. This would require access to weather resource measurements for each individual generating unit. The total generation for a site is however very complex to estimate, with several additional factors that need to be taken into account. For example, for a wind farm, in addition to wind speed itself, wind direction, turbine distancing and configuration within the turbine array would all need to be modelled to calculate deemed output accurately. A process of ongoing re-calibration or testing of actual output against modelled output using the assumed input parameters may be required to tackle gaming opportunities involving deliberately skewed parameter selection.

## Chapter 7: Flexibility

### 35. Are we considering all the credible options for reform in the flexibility chapter?

☒ Yes ☐ No ☐ Don’t know ☐ No opinion

*Please expand on your response here:*
We welcome the 'twin track' approach to market reform for flexibility. As highlighted in the consultation document, effective operational signals should serve as the foundation for incentivising investment in flexible assets. Greater locational and temporal granularity in these signals should therefore be both the starting point and the enduring basis on which to drive an efficient installed capacity ratio between variable and flexible assets.

Whilst there has been substantial success in the growth of renewable generating capacity in GB, there is now a need to re-balance policy support. Flexible assets are critical to enabling the integration of far higher levels of intermittent generation into the electricity system. Enduring holistic market design and policy must achieve an optimal ratio between variable renewables and flexibility. There is also an interim need to accelerate investment in flexible assets as soon as possible, whilst wholesale reforms are being designed and implemented. We therefore believe that the options for reform under consideration in the flexibility chapter therefore all warrant further investigation at this stage. We have not yet identified any further credible policy interventions beyond those identified in the consultation document. We are however undertaking further analysis of flexibility incentives as part of Phase 4 of our ESO Net Zero Market Reform programme, the results of which will be shared at the earliest opportunity with BEIS and published later this year.

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

*Please provide your response here:*
As summarised in our response to Q16 we believe that stronger operational signals in the form of locational wholesale pricing (either nodal or zonal) would significantly increase arbitrage opportunities and therefore the incentive to invest in flexible assets, both on the supply- and demand-sides. See also our response to Q35.

In addition, introducing reforms to the capacity adequacy incentive mechanism which are linked to real-time system margins, such as Reliability Options (including Reverse Reliability Options) or Capacity Payments/Adder, would offer additional "missing money" for specific flexible assets. Longer-duration storage assets would be rewarded proportionally to the system value of their sustained response capability, in contrast to the existing Capacity Market that rewards duration on an ex-ante basis, with de-rating factors. This will be critical to incentivising the wider range of flexible assets required to meet the 2035 commitments.

Over the longer term, the above-mentioned market design reforms may facilitate the withdrawal of bespoke support arrangements for FOAK technologies such as long-duration storage or green hydrogen, once they reach maturity.

For mature flexible technologies, additional financing support to stabilise revenues rather than provide an explicit subsidy may be appropriate due to high Capex to Opex ratios, on a consistent basis with support provided to variable renewables.

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

☒ Yes ☐ No ☐ Don't know ☐ No opinion

*Please expand on your response here:*
We agree that a revenue cap and floor mechanism for flexible assets warrants further investigation at this stage.

As mentioned in our response to Q36, there exists uneven treatment in application of policy support to supply-side, demand-side and flexible resources that needs to be rebalanced, especially for first-of-a-kind technologies and/or those with higher Capex costs. However, in order to avoid potential ongoing market distortions, such support should be considered as an interim measure to bridge the gap to the more enduring solution of a reformed wholesale market that creates more valuable arbitrage opportunities via greater temporal and locational price granularity.

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

*Please provide your response here:*
ESO is conducting further analysis on flexibility policy options, including a revenue cap and floor as part of Phase 4 of our Net Zero Market Reform programme. This will include consideration of whether and how a cap could be designed to ensure assets are incentivised to operate flexibly and remain available if they reach their cap. The results of this analysis will be shared at the earliest opportunity with BEIS and published later this year.

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

*Please provide your response here:*
ESO is conducting further analysis on flexibility policy options, including a revenue cap and floor as part of Phase 4 of our Net Zero Market Reform programme. This will include consideration of whether and how a cap could be designed to ensure effective competition between flexible technologies, including small-scale flexible assets.

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

☒ Yes ☐ No ☐ Don't know ☐ No opinion

*Please expand on your response here:*
We agree that all of the options for a reformed Capacity Market should continue to be considered at this stage. ESO is currently conducting further analysis on flexibility policy options as part of Phase 4 of our Net Zero Market Reform programme. This will include further analysis of the relative merits of the different Capacity Market reform options. We will publish our analysis later this year.

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

*Please provide your response here:*
ESO is currently conducting further analysis on flexibility policy options within Phase 4 of our Net Zero Market Reform programme. This work will include consideration of which flexibility characteristics it would be most appropriate to value within a reformed Capacity Market with flexibility enhancements. We will also consider whether and how these enhancements could be designed to maximise the value of flexibility while avoiding unintended consequences. We will publish our analysis later this year.

**42. Do you agree that we should continue to consider a supplier obligation for flexibility?**

☐ Yes ☒ No ☐ Don't know ☐ No opinion

*Please expand on your response here:*
We agree that supplier obligations should continue to be considered if they are based around well-defined policy outcomes to be achieved by the market (e.g. decarbonised electricity). Flexibility, however, is a means to an end, not a policy outcome. See our response to Q43.

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

*Please provide your response here:*
Supplier obligations work most effectively when based around well-defined policy outcomes to be achieved by the market. Flexibility is a means to an end; setting flexibility targets may not be an efficient approach and consumers' preferences need to be considered. A more efficient approach would be to frame suppliers' obligations around market outcomes targeted by public policy - such as

cost-effective decarbonised energy/electricity service, reliability, or decarbonised buildings - because this would drive suppliers to optimise across supply and demand as well as across different fuels, and to use flexibility from their resource portfolios. See our response to Q26 and Q56 regarding suppliers' obligations for carbon and reliability.

Effective monitoring of the retail market should play a key role in identifying whether the retail market is successfully bringing forward demand-side flexibility or not.

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

*Please provide your response here:*
From an efficient system operation perspective, it is necessary that flexibility incentives are linked to real-time prices. Flexibility investment depends on the wholesale market being able to accurately reveal true system value and for flexible resources having unhindered access to this value. Therefore, we are exploring options based on improving the functioning and performance of the wholesale market, particularly through centralised dispatch and more granular locational and temporal price signals. Support schemes for flexibility should not be based on determining peak demand periods in advance as the risk of this being inaccurate is high and will increase as net demand becomes more difficult to predict with growth in the share of variable renewables in the power mix. We do not believe that the difficulties in setting the required parameters for a Clean Peak Standard ex-ante can be overcome to a sufficient extent for this policy option to be efficient. We agree that the miscalibration of multipliers and peak periods would inevitably lead to outcomes misaligned with system needs. See our response to Q43.

## Chapter 8: Capacity Adequacy

### 45. Are we considering all the credible options for reform in the capacity adequacy chapter?

☐ Yes ☒ No ☐ Don't know ☐ No opinion

*Please expand on your response here:*
Most of the credible options for reform have been included in the capacity adequacy chapter, whilst noting that the optimal solution may be to implement more than one of these options in parallel. The one missing option that we have identified is Reverse Reliability Options, which we discuss in our response to Q55.

### 46. Do you agree that we should continue to consider optimising the Capacity Market?

☒ Yes ☐ No ☐ Don't know ☐ No opinion

*Please expand on your response here:*
We believe that BEIS should continue to consider ways to optimise the Capacity Market. We have stated elsewhere in our response that we do not believe the Capacity Market in its current form is likely to be the optimum mechanism via which to secure capacity adequacy over the longer term. It is worth exploring how it can be optimised as it will play an important role in the interim, even if alternative designs are to be implemented for a net zero market design. Continuing to consider optimising the Capacity Market is therefore part of a pragmatic least-regrets approach overall. We

will continue to support BEIS and Ofgem in our role as system operator (as well as in our role as delivery body) with any further analysis required to assess options for this element of market design.

## 47. Which route for change - Separate Auctions, Multiple Clearing Prices, or another route we have not identified - do you feel would best meet our objectives and why?

☐ Separate Auctions ☐ Multiple Clearing Prices ☐ Another Route

☐ Don't know ☒ No opinion

*Please expand on your response here:*
Further work is required to determine which routes for reform of the Capacity Market would best meet the objectives. ESO is conducting further analysis on options for a reformed Capacity Market as part of Phase 4 of our Net Zero Market Reform programme. We intend to publish this analysis later this year.

## 48. Do you consider that an optimised Capacity Market alone will be enough for ensuring capacity adequacy in the future, or will additional measures be needed?

*Please provide your response here:*
A strategic reserve could be considered as a complement to any capacity renumeration mechanism, including an optimised Capacity Market – see our response to Q50.

## 49. Are there any other major reforms we should consider to ensure that the Capacity Market meets our objectives?

*Please provide your response here:*
We have been supporting BEIS in their review of the Capacity Market. This included BEIS' Call for Evidence in 2021 which looked at shorter- and medium- to longer-term changes, including in relation to decarbonisation and delivery assurance. Beyond the issues covered in that Call for Evidence, those identified in the REMA consultation document and the ESO's responses to those consultations, we have not identified any other major issue to be considered regarding the Capacity Market.

## 50. Do you agree that we should continue to consider a strategic reserve?

☒ Yes ☐ No ☐ Don't know ☐ No opinion

*Please expand on your response here:*
A strategic reserve should continue to be considered. A strategic reserve could be used on its own or could potentially complement any capacity renumeration mechanism based on the following justification:

- Load factors of high carbon assets are expected to decline, and such plant may become uneconomic despite receiving revenues from any capacity renumeration mechanism – essentially needing additional subsidies if they are to stay in operation

- Effective market design reforms should enable efficient exit of high carbon and inflexible assets no longer needed (with any exits raising the wholesale prices and load factors for remaining assets) - locational energy pricing would play an important role here to reveal and reward plant most valuable to the system

- Uneconomic high carbon plant might still be needed to ensure system security/reliability, providing adequacy and resilience during low-probability extreme events or shocks (with extended durations of supply/demand imbalances expected in future)

- Uneconomic high carbon plant might still be needed to provide system services (flexibility / operability) if low carbon alternatives are not available. Trying to optimise a market-wide capacity renumeration mechanism to reward specific capabilities of capacity while retaining liquidity for competition may be prohibitively complicated and cost inefficient – it is more efficient to reform the wholesale market for economic resources. For uneconomic resources, bespoke procurement through a strategic reserve could be more cost-efficient.

- There could also be a need to move high carbon assets out of the wholesale market in order to ensure that carbon emissions reductions from the power sector align with the required decarbonisation trajectory to 2035.

- For situations where subsidies are needed, strategic reserves can play an important role to keep resources in the system that are still needed but:

    - These resources should not compete in the wholesale market as they can potentially distort competition

    - A strategic reserve should be implemented strictly in line with best practice design guidelines (such as EU Electricity Regulation 2019/943 Article 22) in order to minimise the risk of: wholesale market distortions; exploitation of market power; the ‘slippery slope’ issue as experienced in GB during 2015-2017 with the Supplemental Balancing Reserve; opaque ad-hoc emergency procurement of high carbon resources

## 51. What other options do you think would work best alongside a strategic reserve to meet flexibility and decarbonisation objectives?

*Please provide your response here:*
Reforming the wholesale market to ensure it accurately reflects system value is the highest priority, including consideration of the capacity payment/adder option. On decarbonisation, ensuring policy can deliver the emissions reduction trajectory to 2035 for power will also be crucial.

Specially regarding capacity renumeration, a strategic reserve can complement any option (see our response to Q50). We believe that the option of implementing Centralised Reliability Options, and Reverse Reliability Options for long-duration storage and demand turn-up, alongside a strategic reserve warrants further investigation, for the reasons set out in our response to Q55.

## 52. Do you see any advantages of a strategic reserve under government ownership?

☒ Yes ☐ No ☐ Don’t know ☐ No opinion

*Please expand on your response here:*
We believe the advantages and disadvantages of a strategic reserve under government ownership are best considered at a later point in time when the preferred whole package of reforms is known. We presume that the ESO (FSO in future under current reform proposals) would play an important role in any strategic reserve delivery. If a strategic reserve were to be pursued as a viable option, we would therefore support government and the regulator in considering implementation options.

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**53. Do you agree that we should continue to consider centralised reliability options?**

☒ Yes ☐ No ☐ Don't know ☐ No opinion

*Please expand on your response here:*
We agree that Centralised Reliability Options should continue to be considered, for the reasons set out in our response to Q54.

**54. Are there any advantages centralised reliability options could offer over the existing GB Capacity Market? For example, cost effectiveness or security of supply benefits? Please evidence your answers as much as possible.**

*Please provide your response here:*
We see several potential advantages of Centralised Reliability Options (CROs) over the existing Capacity Market (CM).

**Stronger incentives to align availability with all times of system stress (not just winter peak)**

The incentives for availability at times of system stress are stronger with CROs than the existing CM. BEIS has been considering changes to the penalty regime in the CM with a view to strengthening delivery assurance. As highlighted in the consultation document, with a CRO regime, non-delivery at option exercise results in a directly cost-reflective and uncapped penalty based on the real-time market price minus the strike price, which is likely to be substantial. This greatly reduces the risk of over-rewarding less reliable capacity that may not be available at times of system stress.

**Stimulating demand-side participation in securing system security**

CROs would stimulate demand-side participation in securing system security by rewarding its full value as measured by real-time market prices. Demand-side assets would receive payments based on their actual capability, rather than an administered estimate of baseline capacity. It would also accelerate the participation of demand-side assets by removing the current barrier to entry of mandatory DSR tests over a two-year period to establish their 'Proven Capacity'.

**Lower ongoing regulatory risk compared to existing Capacity Market due to fewer administered parameters**

We believe that CROs would be subject to less ongoing regulatory risk than the current Capacity Market. The Capacity Market relies on the delivery body to set various administered parameters, such as derating factors and non-delivery penalties. These are used to calculate assets' theoretical availability and reward, considering their performance at times of system stress over the winter peak. Whilst the CRO would also require parameters such as setting of the strike price and determination of the demand curve for the auction, to be set by the central authority administering the scheme, the overall importance of administered parameters should be greatly diminished. That said, as with a reformed Capacity Market, CROs could be designed, if considered desirable and appropriate, to favour low carbon and flexible capacity by having a minimum volume of low carbon capacity and multipliers to value flexibility.

Nevertheless, we believe that ongoing regulatory risk of parameter review, (such as changes to non-delivery penalties to address the weak delivery incentives acknowledged in the recent Capacity Market Call for Evidence), would be greatly reduced for a CRO compared to a CM. As with all policy interventions, however, the detailed design of CRO would be critical to ensure the mechanism is as effective as possible and must be set effectively to minimise market distortions. Lessons learned from implementing CROs can be taken from Ireland and Italy - see here.

**Importance of respecting real-time price signals and limiting market distortions**

Under the existing CM, generators receiving capacity payments can be more aggressive in pricing the electricity they generate, which may in turn suppress wholesale prices, making it harder for other generators to recover their capacity costs from inframarginal profits on electricity. This perpetuates the need for the capacity revenues. By contrast, CROs do not give rise to these distortions as they are a financial instrument and a risk-sharing mechanism. The buyer (i.e. ESO acting on behalf of consumers) is essentially buying insurance against the availability of generation and at the same time, a hedge against very high prices. At the same time, the seller (e.g. generator) earns a reliability premium (derived from a competitive auction) that is based on its opportunity cost that should factor in any loss of revenue during the period of energy market prices above the strike price. The wholesale market continues to function 'business as usual' without distortions so long as distorting design features are not introduced (e.g. de-rating factors; different contract lengths; price caps; mandatory participation; stop loss limit – see here).

**Adaptability to a more decentralised model in the future**

In the future, if performance of and confidence in the retail market were significantly improved and with exploitation of digital and data technology, the CRO could be evolved into a Decentralised Reliability Option (DRO). This would strengthen incentives on suppliers to use resources in their own portfolio for reliability, including distributed flexible resources, enabling consumers to express their willingness to pay and potentially reducing system costs for all consumers. However, as outlined in Q56, we do not believe that Decentralised Reliability Options or obligations can currently be considered as a viable option for securing reliability.

## 55. Which other options or market interventions do you consider would be needed alongside centralised reliability options, if any?

*Please provide your response here:*
A Reverse Reliability Option (RRO) could also be used in conjunction with Centralised Reliability Options in order to enable hedging for electricity storage and DSR. This financial instrument would give the option holder the right, but not the obligation, to sell energy at a fixed strike price (acting as a floor price), essentially constituting a put option (i.e. right to sell), in the same way that a CRO is equivalent to a call option (i.e. right to buy). This would provide greater certainty on costs and a guaranteed additional source of revenue ahead of real-time. ESO could potentially be the central seller of RROs (just as it could be the central buyer of CROs) and would contract for a number of put options, paying a pre-determined premium or option fee to the buyer (i.e. storage/DSR providers). The amount of RROs to procure would need to be estimated based on several factors, but the level of non-dispatchable demand would be an important factor. A combination of CROs and RROs supporting the investment case for long-duration storage in an enduring market design could enable phasing out of FOAK policy support in the longer-term. Auctions for CROs and RROs could potentially be linked and traded as a single instrument.

As outlined in our response to Q50, a strategic reserve alongside could also be used to complement Centralised Reliability Options and warrants further investigation. Compared to a CRO alone, we believe that a strategic reserve in addition to a CRO, if well designed and implemented, could bring several advantages.

## 56. Do you agree that we should not continue to consider decentralised reliability options / obligations? Please explain your reasoning, whether you agree or disagree.

☒ Yes ☐ No ☐ Don't know ☐ No opinion

*Please expand on your response here:*
Given the recent instability in the retail market, we do not believe that Decentralised Reliability Options or obligations can currently be considered as a viable option for securing reliability. However, were Centralised Reliability Options to be introduced, the responsibility for procurement could be transferred at a later stage to suppliers if retail market conditions evolved to be more conducive to this. We agree that it is appropriate to remain open to a more decentralised policy approach over the longer term given the potential benefits for mobilising demand-side flexibility, driving innovation in energy services (by motivating retailers to exploit digitalisation, data, automation and artificial intelligence for the benefit of consumers) and enabling choice for consumers.

**57. Are there any benefits from decentralised reliability option models that we could isolate and integrate into one of our three preferred options (Optimised Capacity Market, Strategic Reserve, Centralised Reliability Option)? If so, how do you envisage we could do this?**

*Please provide your response here:*
We have not identified any benefits from Decentralised Reliability Option models that could be isolated and integrated into the optimised Capacity Market or strategic reserve. As stated in our response to Q56, it would be relatively easy to move from Centralised Reliability Options to Decentralised Reliability Options if the conditions were right in the retail market. In addition, there would be benefits for the demand-side in introducing Reverse Reliability Options, the auctions for which could be combined with Centralised Reliability Options, as described in our response to Q55.

**58. Do you agree that we should not continue to consider a capacity payment option? Please explain your reasoning, whether you agree or disagree.**

☐ Yes ☒ No ☐ Don't know ☐ No opinion

*Please expand on your response here:*
We believe that the capacity payment option should be given further consideration. In our view, a high-level principle to ensure efficient procurement of capacity adequacy is that its renumeration should be linked to real-time dynamic price signals, which reflect the varying value of available capacity between different settlement periods. As set out in our response to Q54, we believe that Centralised Reliability Options is a capacity renumeration mechanism that can more effectively achieve this compared to a centralised Capacity Market, even if optimised. As a capacity payment is an alternative means of achieving this, this option should be retained for further consideration at this stage.

The consultation document highlights the fact that under a capacity payment system, at times of lower margin the price will be higher and therefore the overall price achieved by a generator will depend on the timing of its availability. It proceeds to identify this as a disadvantage due to the creation of uncertainty for new projects. In contrast, we believe that the dependency of price achieved on availability timing is entirely appropriate to incentivise capacity that is able to be available at times of system stress. The risk of uncertainty in availability should be placed on those best placed to manage it. This is the capacity providers themselves, rather than on the consumers, as is currently the case with the Capacity Market.

The other hypothesised disadvantage of the capacity payment option is the risk of over-compensation if the price is set too high. However, we do not see this as a disadvantage unique to a capacity payment model as the same risk of overcompensation applies to the existing Capacity Market. For the latter, the risk is a volume risk rather than a price risk. Generation capacity from multiple technologies is rewarded for theoretical average derated availability at times of system stress, much of which cannot be guaranteed to materialise when required, even at derated levels.

We do not believe that the evidence presented from the Irish Capacity Payment Mechanism is a compelling basis for not continuing to consider capacity payments. The observation that the level of payments was not always highest when capacity was scarce is followed immediately in the Poyry report by a list of contributing factors, all of which relate to design parameters specific to the Irish capacity payment mechanism which it later recommends should be reformed:

*"the level of payments is not always highest when capacity is scarce and the variance between the lowest and highest payments is low. This is due to the diluting effect of (a) the monthly distribution of the pot; (b) use of a Flattening Power Factor (FPF) which reduces the spread of ex-ante and ex-post payments between high and low LOLP periods; and (c) the high weighting placed on ex-ante and fixed payments under the current mechanism."*

Any issues identified with the Irish model over a decade ago are not necessarily representative of capacity payment systems in general. Moreover, no administered capacity adequacy renumeration mechanism will ever have perfect foresight of 1) when margins will be tightest or 2) when the rewarded capacity will be available. The level of payments under the existing Capacity Market is unlinked to 1) and estimates 2) using ex-ante calculated average derating factors. Under a capacity payment system, prices are linked far more closely to 1) and payments are matched exactly to real-time availability.

Overall, we believe that capacity payments may be a more accurate form of renumeration than the existing Capacity Market and should therefore not be excluded as an option from consideration over the status quo market design at this stage. As for all capacity renumeration mechanisms, capacity payments could also be implemented in conjunction with a strategic reserve (see our response to Q50).

**59. Do you agree that we should not continue to consider a targeted capacity payment / targeted tender option? Please explain your reasoning, whether you agree or disagree.**

☒ Yes ☐ No ☐ Don't know ☐ No opinion

*Please expand on your response here:*
We agree that a targeted capacity payment/ target tender option should not be considered further as a key element of enduring net zero electricity market design. Whilst such mechanisms may be more suitable for securing investment in first-of-a-kind (FOAK) technologies such as CCUS, their widespread use at scale for mature technologies would have distorting impacts on the market, potentially stifling innovation and risking over-or under-investment in targeted technologies.

**60. Do you agree with our assessment of the cost effectiveness of a targeted capacity payment / targeted tender option, and the risk of overcompensation? If not, why not?**

☒ Yes ☐ No ☐ Don't know ☐ No opinion

*Please expand on your response here:*
We agree with the assessment of the cost-effectiveness of a target capacity payment/ targeted tender option, and the risk of overcompensation. Even in relatively stable market conditions, any mechanism relies on central forecasts of appropriate volumes and price levels which are inevitably subject to significant forecasting error risk. Overcompensation risk can therefore be expected to be

even more substantial given the period of unprecedented system transformation required to meet net zero.

### 61. Are we considering all the credible options for reform in the operability chapter?

☒ Yes ☐ No ☐ Don't know ☐ No opinion

*Please expand on your response here:*
We broadly agree that the operability chapter considers credible options for reforms, and we welcome the breadth of options explored e.g. the interactions between different marketplaces (ancillary services with CfD and CM), coordination between the DNOs and the ESO, and striking the balance between short- and long-term contracts. Many of these align to existing market reforms that the ESO is undertaking, e.g., the Enduring Auction Capability program which is looking to co-optimise procurement of response and reserve, as well as the Stability and Reactive Market Design innovation projects which are seeking to strike the optimal balance between short- and long-term markets for these operability services.

In addition to the proposed options within this consultation, we are considering using code obligations to enhance the provision of specific ancillary services. For example, mandating the provision of stability services (e.g., inertia) from non-synchronous generation through the installation of Grid Forming Convertors could significantly reduce the cost of procuring such services.

### 62. Do you think that existing policies, including those set out in the ESO's Markets Roadmap, are sufficient to ensure operability of the electricity system that meets our net zero commitments, as well as being cost effective and reliable?

☐ Yes ☒ No ☐ Don't know ☐ No opinion

*Please expand on your response here:*
ESO is continually reforming its ancillary and balancing services markets – striving towards zero-carbon reliable operability of the system at lowest cost to consumers. What we are doing, and why, is outlined in our annual Markets Roadmap publication. However, these reforms are designed within the constraints of the existing wider market and policy landscape, and while we are on track to deliver our zero-carbon operation ambition by 2025, we believe that more substantial reforms to wider markets and policies, in particular reform of the wholesale market, will be needed if we are to cost-effectively deliver a fully decarbonised, operable, and reliable power system by 2035.

**Reforms to ESO operability markets**

Below we outline ongoing and planned reforms to our operability markets, driven by changes in both our operability requirements as well as in the landscape of providers, as we progress towards net zero.

***Stability and voltage: Managing the decline of inertia and reactive power absorption capabilities as synchronous generation exits the system***

- Historically we have procured short-term requirements in voltage and stability services through the Balancing Mechanism, involving costly redispatch of carbon-intensive generation.
- To address the longer-term shortfalls as a result of retiring synchronous generation, we introduced long-term contracts in the form of Pathfinders to stimulate investment in high-Capex assets.

- As our requirements become greater and more volatile, we are exploring the creation of dedicated long- and short-term markets for stability and voltage services, which will reduce the need for redispatch, saving cost and carbon (e.g. an estimated ~£58 million saving from procuring short-term stability in 2030).
- We are also considering exploring Grid Code modifications as a potential route to increasing the contribution of zero-carbon generators to meeting both our stability and reactive requirements.

These reforms should enable us to reliably procure zero carbon stability and voltage services at a lower cost to consumers.

***Response and reserve: Managing a more volatile and unpredictable system as it becomes more dominated by renewables***

- Response: the ESO has designed and implemented a suite of faster acting response products to arrest and recover from faster frequency deviations: Dynamic Containment, Dynamic Moderation and Dynamic Regulation. To open these markets up for the participation of weather-driven generation, we have also transitioned from monthly procurement, to weekly, and now to Day Ahead (DA) timescales. We are currently exploring the merits of intraday procurement.
- Reserve: our current needs are procured through carbon-intensive markets, such as the BM. We are phasing out these existing products and introducing Quick Reserve and Slow Reserve whose granular delivery windows are expected to result in higher contributions from weather-driven technologies such as wind. We anticipate that by 2025 these new markets will mature ensuring a wide range of technology types can participate.
- Co-optimisation: we are developing an Enduring Auction Capability (EAC) which will provide a co-optimised assessment algorithm to procure day-ahead response and reserve services.

Our new suit of response products has already enhanced the ESO’s toolkit to manage frequency deviations in shorter timeframes compared to our previous products, whilst utilising zero-carbon technologies such as battery storage. Our planned reforms to reserve products will help us manage pre- and post-fault conditions more effectively in comparison with the existing suite, whilst benefitting from increased participation of weather-driven technologies. The combination of closer to real-time procurement and increased liquidity within the response and reserve markets will increase the ESO’s toolkit to maintain system security whilst facilitating the transition to zero-carbon system operation.

Once procurement of response and reserve is co-optimised through the EAC, we believe these markets will provide a better user experience and more efficient markets due to clearer price signals. However, considerable overall system efficiencies would be realised if these services would be co-optimised with energy – see our response to Q68.

***Thermal: Employing tactical interim solutions before enduring solutions are deployed***

- Thermal congestion occurs when there is insufficient network capacity to transport electricity from where it is generated to where it is consumed. Managing thermal congestion on our network in 2021 cost £1.2bn and accounted for c.50% of total ESO balancing costs, up from 26% in 2010. The issue is projected to dramatically increase over the coming decade, as GB accelerates its build of low carbon generation.
- Under current arrangements, transmission-connected assets have ‘firm’ access to the network, meaning they are remunerated for electricity that cannot be delivered because of network congestion. ESO’s primary tool to address network constraints in operational

timeframes is the Balancing Mechanism (see also below), whereby assets 'behind' constraints are paid to reduce generation, while assets 'in front' of constraints are paid to increase generation to balance the system.

- Accelerated build and reinforcement of the transmission network will significantly reduce congestion. ESO's Holistic Network Design, that supports the connection of 50 GW of offshore wind by 2030, is expected to save consumers c.£5.5bn in constraint costs, and reduce $CO_2$ emissions by 2 million tonnes, between 2030 and 2032 due to reduced thermal constraints.
- ESO has also introduced several tactical interim solutions as detailed within our 2021 Markets Roadmap to manage constraints on the system. These include the deployment of Local Constraint Markets, Regional Development Programmes (RDPs) and a Constraint Management Pathfinder.
- Despite these measures, ESO projects c.£3bn annual constraint costs in 2034. As explained in Q10 and throughout NZMR, we believe that locational wholesale pricing is required to address the issue of thermal congestion.
- Nodal pricing would reduce thermal congestion costs by incentivising assets behind constraints not to dispatch if the network is congested, thereby avoiding the need for redispatch. By revealing the true cost of energy behind constraints, there would be significant incentives for demand-side users, such as electrolysers and energy-intensive companies, to locate where there is surplus generation.
- Locational pricing would therefore manage the cost of thermal congestion and offers a long-term mechanism for ensuring GB optimises its renewable generation and network capacity.

***Restoration: Utilising a growing diversity of service providers***

- The rapid deployment of flexibility on the distribution network provides the ESO with an opportunity to diversify our restoration service providers. Our world-first Distributed Restart Project seeks to secure this service from distributed energy resources, saving £115m by 2050 due to increased competition and reduced generator readiness costs. We are also developing a bespoke tender for restoration from wind generation.
- Furthermore, by the end of 2026 we will meet BEIS' new Electricity System Restoration Standard, requiring us (in the unlikely event of a blackout) to restore 60% of demand within 24 hours, and all electricity demand within 5 days. The steps we are taking to diversity the providers of restoration services will contribute to us meeting this requirement in a cost-effective and low carbon manner.

***The Balancing Mechanism: Securing operability under an increasingly volatile network***

- The BM is ESO's primary tool to balance the system and to maintain reliability in operational timescales. The BM was conceived as a 'residual' market to fine-balance generation and demand, and to manage any system constraints that arose. It is therefore used to dispatch units for the following reasons: Thermal and RoCoF constraints, Response, Reactive, Short Term Operating Reserve and Operating Reserve.
- Transitioning to a decarbonised energy system with flexible demand has led to increased volatility and a proliferation of system constraints. Because the wholesale market trading and clearing process does not currently account for system considerations, there is considerable pressure on ESO to resolve system issues after gate closure, via the BM. A consequence is BM redispatch actions accounting for c.5% of demand in 2009, versus sometimes 65% today.
- The BM is therefore undergoing reform in both the short and medium term:

*Short-term priorities:*

- Improvements to demand forecasting
- Widening access to the BM by integrating all assets (targeting <1MW and decimal bids).
- Implementing findings from the Balancing Costs project, which assessed balancing-related processes, systems, data, and policy across ESO and identified areas where costs could be reduced.

*Medium-term priorities:*

- Balancing Transformation Programme: we understand that ESO systems and processes are the key enabler to successful balancing outcomes. The Balancing Transformation Programme is developing the 'Open Balancing Platform' (OBP) in concert with industry to ensure ESO's new capability is set up to utilise the capabilities of future providers, such as aggregators and residential flexibility.
- As a consequence of our Balancing Market Review in 2022, to understand the factors driving high-cost days in late 2021, we are planning to investigate potential short and long-term reform options, including changes to bidding design.
- We have listened to industry concerns over skip rates within existing systems. As part of our BP2 commitments, we are investigating if there are changes that we can make to existing systems before we get new facilities in the Open Balancing Platform (OBP). We will engage with the industry on our findings once we have completed our investigation.

In the longer-term:

- As discussed above, we believe the Balancing Mechanism is fundamentally unsuited for the level of network-related system constraints projected over the next decades. A key issue is that, because the BM does not resolve issues prior to gate closure, consumers continue to pay in the wholesale market for energy that is physically undeliverable.
- The whole-system cost of managing constraints in this manner is wider than ESO actions: the unpredictability of being chosen to dispatch in the BM means that participating generators are exposed to an unreliable revenue stream, while suppliers (and therefore consumers) are exposed to unpredictable BSUoS costs. Both generators and consumers therefore face unhedgeable risk regarding constraint resolution.
- Moving to nodal pricing would devolve information on network constraints to the wholesale market so that these can be resolved prior to gate closure in a manner that can be forecasted and therefore hedged. This would reduce costs across both generation and demand and return ESO balancing actions to being residual.

***Coordination with DSO markets***

- As DSOs become more active market facilitators, it is fundamental that markets are coordinated across the whole system to optimise value for consumers. More detail on these coordination activities can be found in Q64. We are also developing an ESO Distributed Flexibility Strategy. This will produce a set of actions to reform our markets to facilitate growth and participation of distributed flexibility.

***We will always need to adapt operability markets to unforeseen short-term shocks***

- This Winter provides a good example of how operability and system security issues can develop or shift direction suddenly and dramatically, and we will always need to be flexible to adapt to unforeseen circumstances. The Covid lockdowns were another good example.
- Ahead of Winter 2022/23, we are launching a Demand Flexibility Service, allowing the ESO to access additional flexibility when the national demand is at its highest, during peak winter

days, that is not currently accessible to the ESO in real-time. This will help secure our networks this winter, whilst helping us drive towards net zero.

- At the request of BEIS, the ESO has agreed contracts with three generating companies to extend the life of coal fired power plants this winter. This will deliver around 3GW de-rated capacity. The new winter contingency contracts will only be used as a last resort to ensure resilience and security of supply.
- While there may always be a role for temporary mechanisms, wider market design reforms can help strengthen the system's resilience to shocks.

Our operability markets are increasingly intertwined with wider markets, including the wholesale market, the Capacity Market and CfDs. Market participants also rely on multiple markets for stacking revenues and can dynamically switch between markets, though with this comes inefficiencies that could be resolved through central dispatch co-optimising energy and reserves (see our response to Q68). In our response to Q66 (and Q29 on solutions) we discuss how the current CfD design is discouraging generators, or distorting their bid behaviour, in providing balancing and ancillary services, ultimately increasing the ancillary services requirement, and increasing costs.

We continually adapt our operability markets to be coherent with the evolving wholesale market context, but we believe that there is opportunity for reducing distortions and consolidating and streamlining system value into the wholesale market to improve both wholesale and balancing market outcomes, while driving down carbon emissions, delivering cost savings for consumers and reducing transaction and opportunity costs for market participants – see our responses to questions 10, 17, 24, 29, 63, 66 and 68.

## 63. Do you support any of the measures outlined for enhancing existing policies? Please state your reasons.

☒ Yes ☐ No ☐ Don't know ☐ No opinion

*Please expand on your response here:*

**Option 1: Giving the ESO or Future System Operator (FSO) the ability (or an obligation) to prioritise zero/low carbon procurement.**

We are fully committed to delivering on our responsibilities relating to net zero, whether as ESO or as the FSO. We recognise that new mechanisms and tools may be needed in future to remove carbon emissions from the power sector as we approach 2035. At this stage we do not have a view on the specifics of any such mechanisms.

We would note two points when considering prioritisation of zero/low carbon procurement of balancing and ancillary services:

- It may not be cost-efficient to target carbon abatement in ancillary services procurement if lower-cost abatement opportunities are available in the wider power sector, particularly in the wholesale market
- High carbon plant might still be needed to provide system services (flexibility / operability) if low carbon alternatives are not available
- If centralised dispatch would be introduced, energy and reserves would be co-optimised, shifting carbon emissions associated with reserves from the Balancing Mechanism into the wholesale market, reducing the carbon emissions that would need to be reduced by ESO intervention

The design and use of any such mechanisms to prioritise zero/low carbon procurement must therefore be developed and introduced as part of a wider carbon strategy for the power sector. We are keen to engage with BEIS, and the wider industry, on the development of this carbon strategy. See our response to Q24.

**Option 2: optimal balance between short term and long-term contracts:**

We recognise the efficiencies of a combination of long- and short-term procurement and are exploring this in several of our markets, most notably stability and reactive power markets where we are procuring services in both time horizons through Pathfinders and the BM respectively.

In general, long-term markets will:

- Provide certainty to investors to secure significant new Capex-heavy investments such as synchronous condensers and shunt reactors; and
- Allow the ESO to procure capacity more efficiently and economically in scenarios where there is a frequent, predictable system need. Longer-term contracts can provide certainty to ESO in terms of cost and firm availability, as opposed to procuring volume closer to real-time where there may be fewer providers and hence, insufficient liquidity to drive down cost.

Whereas the benefits of short-term markets include:

- Providing a route to markets for service providers who are unable to make long-term availability commitments e.g., weather-driven generators
- Optimising the dispatch of existing technologies
- Allowing the ESO to cope with uncertain or unpredictable system needs by procuring closer to real-time, reducing the risk of over- or under-procurement.

The ESO recognises the need to be flexible in how we procure different services: there is no optimal split between short- and long-term procurement in any of our markets. The optimal solution will depend on many factors, including the location, magnitude, and frequency of our operational requirements, as well as the types of technology available to best meet them.

**Option 3: Aligning the Capacity Market and CfD tenders with ancillary markets**

ESO has identified the need to better coordinate policy and de-risking support across the whole system, no matter what procurement methods are used. This could help achieve a cost-efficient ratio of variable renewables to flexibility over time and enable the implications for networks, operability and wider markets to be taken into account. The timing of any auctions could also be better coordinated.

**Option 4: Introducing a matrix approach to ancillary service provision.**

As required by the Clean Energy Package, our new frequency response products have been offered as unbundled, meaning that high and low frequency provision is decoupled. We believe that this optionality will lead to greater participation. For example, for battery units, linked bids allow for the provision of both high and low frequency response, whereas an offshore wind generator operating under a CfD may prefer to provide high response only to maximise the opportunity to receive their strike price.

The share of participating linked bids volume for Dynamic Containment has increased from ~3% in November 2021 (the first month it was offered) to ~12% in December 2021. As these markets mature and providers get more familiar with different bidding options, we can assess the full benefit of this functionality. These insights will be fed into our Early Access Competition program.

## 64. To what extent do you think that existing and planned coordination activity between ESO and DNOs ensures optimal operability?

*Please provide your response here:*
As laid out in our 2021 proposed approach to 'Enabling the DSO Transition', we recognise that to ensure optimal operability, the ESO would need to enhance coordination with DNOs across all three roles in development, markets and operations. Through the Energy Networks Associations (ENA)'s Open Networks Programme, the ESO and DSOs are working together to improve alignment via a range of products, such as developing a Common Evaluation Methodology, implementing 'primacy rules' and reviewing the stackability of ESO/DSO products. We are also working directly with DNOs via our Regional Development Programmes to identify and resolve local constraint issues.

In our BP2 published this year, we stated our priority to drive towards a whole system approach, our planned work to further improve our visibility of DER and facilitate DSO transition. We also recognise that to meet the future operability challenge, we will need to do more to facilitate the growth distributed flexibility and have committed to developing our own strategy to identify gaps and propose actions.

## 65. What is the scope, if any, for distribution level institutions to play a greater role in maintaining operability and facilitating markets than what is already planned, and how could this be taken forward?

*Please provide your response here:*
We recognise the growing importance of distribution-level institutions in managing electricity networks given the increasingly decentralised and locational characteristics of our energy system. We believe that the FSO, DSOs and other local institutions such as local authorities must work in tandem, each playing to their respective strengths. Further clarity is required on the activities undertaken by each of these institutions, and how they must evolve to ensure delivery of net zero. Looking forward, we believe a strategy for developing enabling activities, such as data and digitalisation, should be developed.

We believe that a strategic, whole energy system approach to regional/distribution markets are needed to meet net zero. More consistent local markets for flexibility, that are coordinated with the wholesale market and balancing services markets, should lead to more liquidity with greater participation and clearer incentives.

The proposed whole energy system planning role for the FSO could take on these strategic activities, considering synergies across different fuel types. Furthermore, local authority boundaries do not always align well with functional network areas. It is therefore difficult for local authorities to have the mandate to make meaningful decisions on energy options that impact networks. There may therefore be benefit in an entity, such as the FSO, co-ordinating local requirements with national strategy.

We recognise that DSOs will have greater visibility of flows on their network compared to the ESO, and in certain cases may be best placed to procure a service to manage local operability challenges e.g. managing distribution network thermal constraints. In this case, market operation within distribution level could remain with DSOs, or be moved to another body if the government and regulator identify there is a conflict of interest considered to be unsustainable in the longer term.

Regarding real-time system operation, we believe there is a role for a single body to consider system resilience and emergency management at a strategic level and across fuels. Certain services are better coordinated at the national level: for example, it is neither possible nor efficient to procure frequency response regionally in a fully connected system, since the service is instantaneously provided across the whole network. Whilst the DSOs will have greater visibility of their own networks, the ESO has visibility across the whole network, rather than individual GSP groups, and therefore we do not see the merit of DSOs managing this type of service.

Given the huge projected growth of flexible electricity capacity at distribution level, we see strong value in specific system operations sitting with DSOs, to make best use of local knowledge of assets. Key to this debate of the DSOs playing a greater role in maintaining operability and facilitating markets is the bi-directional coordination between them and the ESO. In working with various DNOs through Regional Development Programmes there is clear evidence of the merits of coordinating to address certain issues, e.g. unlocking network capacity to reduce constraints whilst opening a new revenue stream for market participants. Pivotal to the continued success of ESO/DSO interactions is the clear route for communication and primacy and ensuring that this information is known by all parties to mitigate the scope for conflicting actions being taken, likely at a cost to the end consumer. We have led thinking in this area through our participation in the ENA Open Networks project and have demonstrated the value ESO can bring to these developments drawing upon our expertise and ensuring a consistent outcome across GB.

In summary, it is vitally important to drive a collaborative whole energy system approach through alignment and consistency with clear boundaries and accountabilities across government, national, regional, and local authorities; planning; markets; system operation; regulation; and to do so on a whole energy system basis for both electricity and gas (natural and hydrogen) and other emerging sectors.

### 66. Do you think that the CfD in its current form discourages provision of ancillary services from assets participating in the scheme? If so, how could this be best addressed?

☒ Yes ☐ No ☐ Don't know ☐ No opinion

*Please expand on your response here:*
The current CfD design can discourage participating assets from providing ancillary services. There are also elements of the CfD design that increase overall ancillary services requirements.

The CfD design can increase overall requirements for ancillary services for the following reasons:

1. As CfDs reward on output with subsidies based on the difference between the Intermittent Market Reference Price (based on the day-ahead price) and the CfD strike price, CfD-contracted assets cleared in the day-ahead market are incentivised to bid negative prices (up to their CfD strike price) into the intraday and balancing markets to be able to continue generating, even if intraday markets are oversupplied. This can result in artificially low intraday and balancing market prices, and increased ESO turn-down instructions. The cost to ESO of instructing CfD-contracted assets to turn down is also expensive since assets must be made whole relative to their lost subsidy payment.
2. CFD generators subject to the negative pricing rule will still generate at maximum output so long as day-ahead prices are positive. This can create a cliff edge, at the point day-ahead prices are negative, for generators who all want to stop generating at the same time. If there isn't sufficient liquidity in the intraday market, ESO must resolve the steep drop in output in the BM. If they were exposed to market prices, they would dispatch under a wider range of prices reflecting their marginal costs.
3. CfDs incentivise generators to produce maximum power irrespective of the total cost of system management. In the case of intermittent generators, this increases uncertainty of production in the hours leading up to real-time, which increases the system operator's requirements for reserves. Intermittent generators with this incentive are not exposed to the increased costs they cause so have no reason to, for example, indicate a more conservative

production forecast and follow it, which would reduce the system operator's requirements for reserves.

CfD design can also discourage provision of ancillary services from CfD-contracted assets:

4. CfD value is typically greater than ancillary services revenue opportunities such as response and reserve, so CfD generators tend not to participate in these operability markets. This relates to a broader point on the potential benefits of co-optimisation as discussed in our response to Q68.
5. CfD-contracted generators can price in the lost CfD subsidy into their BM bid price, increasing balancing costs if they are accepted.
6. The current structure of the CfD discourages providers from installing the relevant equipment to provide ancillary services. For example, if wind / storage developers voluntarily choose to install grid-forming technology to deliver Inertia and Short Circuit Level (Stability), project Capex would increase, which they would look to recover through their CfD bid price. Increasing their bid would reduce their chance of being cleared in the CfD auction.

These issues could be addressed by, for example:

a. Introducing some price exposure into CfD design. This would incentivise generators to helpfully contribute to system integration, especially if exposed to locational energy pricing (see our response to Q11). For example, a price or revenue floor would incentivise generators to respond to low prices by siting efficiently considering network constraints, co-locate with storage, pursue higher revenues in other markets such as ancillary services markets, or turn down when not needed. Equally, a price / revenue cap that includes some headroom for profit, would strengthen incentives for generators to innovate, site, operate (scheduling maintenance to avoid times of system stress) or trade in different ways to maximise revenues.
b. Introducing central dispatch (as outlined in our response to Q68) that would co-optimise energy and reserves. In this way, generators - now more exposed to prices as in a. above - would not need to choose which markets to participate in to maximise revenues.

### 67. Do you think it would be useful to modify the Capacity Market so that it requires or incentivises the provision of ancillary services? If so, how could this be achieved?

☐ Yes ☒ No ☐ Don't know ☐ No opinion

*Please expand on your response here:*
Reforming the existing Capacity Market to reward capabilities / ancillary services will introduce considerable complexity and reduce liquidity of auctions, especially if alongside other factors being considered such as carbon intensity and flexibility.

Most ancillary services are already able to "stack" their asset revenues in the Capacity Market. For example, an asset can enter into both frequency response and Capacity Market agreements, under the presumption that if they were being used for frequency response when there was a Capacity Market stress event, they would not be penalised.

Recently, ESO worked with Ofgem to modify the rules of the Capacity Market to allow new ancillary services to be added to the list of Relevant Balancing Services more quickly. We do not see an urgent need for further direct requirements or incentives in the Capacity Market for the provision of ancillary services at this stage, whilst noting the need to resolve indirect disincentives for ancillary services provision created in the wider policy design (see responses to Q29 and Q66).

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## 68. Do you think that co-optimisation would be effective in the UK under a central dispatch model?

☒ Yes ☐ No ☐ Don't know ☐ No opinion

*Please expand on your response here:*
Co-optimisation is where a unit that can provide more than one service (e.g. energy, frequency response) can offer for each of the services for which it is authorised and does not need to choose in advance which service to provide. Unlike service stacking, under co-optimisation more than one service can be offered into an auction but only one service can be delivered.

It is first important to distinguish between

I) Co-optimisation of multiple ancillary services
II) Co-optimisation of energy and ancillary services

**ESO is developing the capability to co-optimise frequency response services:**

ESO currently procures different ancillary service products simultaneously in separate auctions. To reduce the risk of market participants 'herding' towards a particular service, because they must choose to provide one or another service, ESO is currently developing the ability to co-optimise frequency response via its Enduring Auction Capability platform. Where a unit can provide more than one service, it will be able to offer (i.e. indicate a volume and price) for each service it is authorised to provide. The clearing algorithm will allocate the unit to the service which best maximises the welfare of the overall market. Co-optimisation of these services is therefore compatible with both central dispatch and the existing GB self-dispatch market model. We will continue to explore the merits of co-optimisation for future ancillary services, such as Reserve.

**Co-optimisation of energy and ancillary services could realise substantial liquidity benefits and reduced costs but requires central dispatch:**

Were GB to move to a centrally dispatched wholesale market, it would be possible for the system operator to co-optimise procurement of energy and some ancillary services. ESO's NZMR Phase 3 report discussed how co-optimising energy and frequency response and reserve (as happens in US nodal markets) could drive significant efficiency savings since:

1. Ancillary service providers would not incur opportunity costs when choosing to provide energy or a balancing service.
2. The system operator can decide whether to allocate the same capacity to production of either energy or ancillary services, depending on what provides most system value.

Co-optimisation of energy and ancillary services would therefore both increase liquidity of frequency response and reserve markets and give the system operator access to a wider range of resources for energy and balancing needs in near real-time. Co-optimisation of energy and ancillary services would also reduce the administrative burden for smaller assets or new entrants, particularly DERs which must currently optimise between the wholesale markets, DNO, local markets and multiple transmission-level markets (e.g. ancillary services, BM, wholesale markets).

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## Chapter 10: Options across multiple market elements

### 69. Do you agree that we should not continue to consider a payment on carbon avoided for mass low carbon power?

☒ Yes ☐ No ☐ Don't know ☐ No opinion

*Please expand on your response here:*
For the power sector, the carbon emissions reduction objective needs to be separated from the objectives to commercialise innovative technologies and to lower the cost of financing through de-risking intervention.

Bulk low carbon power no longer needs subsidies. Large high-Capex assets, however, need de-risking financing intervention to ensure the investment is brought forward in a timely manner and at relatively low cost of capital. Investor confidence must also be retained as REMA reforms are implemented. Any such support, however, must be designed in a way that respects the integrity of the wholesale market and ensures the generator is incentivised to contribute to system integration, which is why we are exploring CfDs with some price exposure, including to nodal prices.

On reducing carbon emissions in the power sector, see also our response to Q24.

### 70. Do you agree that we should continue to consider a payment on carbon avoided subsidy for flexibility?

☐ Yes ☒ No ☐ Don't know ☐ No opinion

*Please expand on your response here:*
As stated in the consultation document, the link to output is problematic if using this type of scheme to support low carbon flexible resources. The priority should be to ensure that the true value of flexibility can be revealed in the short-term wholesale markets and that all resources able to provide the needed flexibility can easily access the markets.

For the power sector, the 2035 decarbonisation objective needs to be separated from the objectives to commercialise innovative technologies and to lower the cost of financing through de-risking intervention. Some innovative flexibility technologies may need innovation support and some high Capex long lead-time technologies might need de-risking support to enable low-cost financing, though it is crucial any such interventions respect the integrity of price signals in the short-term wholesale markets.

To secure carbon reduction at the needed rate in the power sector, the carbon content of the energy actually consumed matters and so carbon standards may eventually need to be applied to electricity purchases/sales/procurement, complementing the ETS. For more detail on our views relating to reducing carbon emissions in the power sector, see our response to Q24.

### 71. Could the Dutch Subsidy scheme be amended to send appropriate signals to both renewables and supply and demand-side flexible assets?

*Please provide your response here:*
We recognise the merit of the basic principle underpinning the Dutch SDE++ subsidy scheme. In theory, it should be more economically efficient to mitigate the externality of carbon emissions by directly rewarding carbon abatement itself, rather than low carbon energy generated. We agree with the concerns raised in the consultation document regarding the range of assumptions required

to calculate the $CO_2$ abatement, without any clawback mechanism when variances against those assumptions result in under-or-over rewarding technologies for their contribution.

### 72. Are there other advantages to the Dutch Subsidy scheme we have not identified?

☐ Yes ☒ No ☐ Don't know ☐ No opinion

*Please expand on your response here:*
We have not identified any further advantages to the Dutch Subsidy scheme beyond those set out in the consultation document.

### 73. Do you agree that we should continue to consider an Equivalent Firm Power auction?

☐ Yes ☒ No ☐ Don't know ☐ No opinion

*Please expand on your response here:*
We believe this is not an efficient option.

Forcing renewables to bear the system costs of their variability on an individual project basis is highly inefficient from a whole system perspective. Cost-efficient balancing needs to be achieved on a whole-system basis, exploiting the benefits of competition across the whole electricity market. We believe this is most effectively achieved using a centralised clearing algorithm (otherwise known as 'central dispatch') that can co-optimise energy, balancing and some ancillary services, as set out in our Net Zero Market Reform Phase 3 report.

We agree, however, that any government-led procurement of mass low carbon power and dispatchable power needs to be better co-ordinated if an optimal power mix is to be achieved. The current approach of procuring capacity based on technology specific targets has helped accelerate the build of renewables but risks resulting in a sub-optimal ratio of weather-dependent generation to dispatchable and flexible assets.

### 74. How could the challenges identified with the Equivalent Firm Power auction be overcome? Please provide supporting evidence.

*Please provide your response here:*
We don't think the challenges can be overcome, as expressed in our response to Q73.

Please provide any supporting evidence in .pdf or Microsoft Word format.

## Do you have any other comments that might aid the consultation process as a whole?

*Please use this space for any general comments that you may have, comments on the layout of this consultation would also be welcomed.*
We are happy to provide verbal feedback on the consultation process and discuss our response further.

Thank you for your views on this consultation. However, as part of the BEIS wider customer survey plans, we would appreciate your views on x, y and z below.

Thank you for taking the time to let us have your views. We do not intend to acknowledge receipt of individual responses unless you tick the box below.

Please acknowledge this reply ☒

At BEIS we carry out our research on many different topics and consultations. As your views are valuable to us, would it be okay if we were to contact you again from time to time either for research or to send through consultation documents?

☒Yes ☐No