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ESO Response to Capacity Market Consultation on proposals to improve security of supply and align with net zero (Phase 2) and call for evidence on Ten-year Review

Dear Sir/Madam,

Thank you for the opportunity to respond to the Capacity Market Consultation on proposals to improve security of supply and align with net zero (Phase 2) and call for evidence on Ten-year Review.

Who we are

As the Electricity System Operator (ESO) for Great Britain, we are at the heart of the energy system, balancing electricity supply and demand second by second.

Our mission, as the UK moves towards its 2050 net zero target, is to drive the transformation to a fully decarbonised electricity system by 2035, one which is reliable, affordable, and fair for all. We play a central role in driving Great Britain's path to net zero and use our unique perspective and independent position to facilitate network and market-based solutions to the challenges posed by the trilemma.

Our transformation to a Future System Operator (FSO) is set to build on the ESO's position at the heart of the energy industry, acting as an enabler for greater industry collaboration and alignment. This will unlock value for current and future consumers through more effective strategic planning, management, and coordination across the whole energy system.

As the EMR Delivery Body, we perform a central role in the delivery of the Capacity Market (CM) and Contracts for Difference (CfD) schemes. We manage the end-to-end process for all CM participants, supporting them through Prequalification and annual Auctions to continuous management of Capacity Agreements. The Delivery Body also works closely with the Department for Energy Security & Net Zero (Government) and Ofgem to ensure that the CM Rules and Regulations enable competitive capacity procurement and facilitate the efficient operation and administration of the CM.

Our key points

As this is a consolidated ESO response to the consultation and Call for Evidence (CfE), it reflects ESO positions on the longer-term development of the CM, which have been previously discussed with Government via the ongoing Review of Electricity Market Arrangements (REMA) and Delivery Body feedback on implementing changes to the current CM design. Unless the Delivery Body is specifically identified, references to "we" reflect an ESO position.

Part A: Capacity Market Consultation

We understand the Government's drive to further bring the CM into alignment with the achievement of net zero targets and strengthen security of supply through the changes proposed in this consultation and recognise that they represent the next step in the continuous evolution of the CM. However, as identified in our response to Part B, our review of energy markets called the Net Zero Market Reforms[1] (NZMR) raises questions about the CM's ability to achieve desired outcomes as the electricity system and markets transform, and identified factors that the Government should consider when deciding whether to further reform the CM. In particular, depending on the extent to which market reforms and other policies are able to reduce greenhouse emissions (e.g. improved matching of demand to available renewable generation; energy efficiency), existing and possibly new gas generation plant may be needed during the transition while investment in long duration, low carbon assets come forward, facilitated by separate support mechanisms.

Regardless, we understand the intention for the changes proposed in this Phase 2 consultation and the Delivery Body is committed to working with Government and delivery partners to facilitate the development and implementation of the proposals. Our preliminary view is that the Delivery Body will be able to implement all the proposed changes ahead of the 2024 Prequalification Window. However, there are a number of areas where further information regarding the detailed policy design is required to enable the Delivery Body to identify the process and system changes and timescales required to enable us to implement them efficiently in our new EMR Portal which is currently planned to go live in May 2024.

Part B: Call for Evidence on Ten-year Review

We understand that the Ten-year Review will have a targeted scope, as wider CM reform is being considered under Government's Review of Electricity Market Arrangements (REMA). The ESO has also conducted its NZMR reforms and have engaged significantly with the Government's REMA team during development of their policy options. Given this, we recommend referring to our NZMR work for a more comprehensive overview of our views on the future of the CM and have responded to the CfE against the overarching themes, rather than to each individual question.

In general, we believe that, if the current CM objectives are retained, then significant changes are needed to ensure they continue be achieved in the future. Specifically, we think the current CM may not be able to cost effectively meet adequacy requirements in the 2030s, when our analysis indicates there will be less frequent but longer duration stress events. Additionally, we recommend considering suitable eligibility requirements that would provide control room visibility and dispatch of all CMUs, including embedded CMUs, reducing the risk it can propose to security of supply.

We think the current governance arrangements work well, particularly following changes such as the introduction of the CM Advisory Group but believe that further improvements could help reduce the risk of errors and gaming, such as strengthening obligations around Directors' undertakings and Independent Technical Experts.

Finally, we understand the importance that CMUs place on secondary trading as a way for them to manage their risk of non-delivery and are supportive of this being reviewed but note that this should be within the context of other elements of the CM Rules, such as under Rule 4.4.4[2] and terminations.

Rather than responding to each question, we address each policy initiative as a whole in Part A and focus on areas that are expected to have a significant impact or we consider warrant further clarification or input from the Delivery Body. For Part B, we have responded against each of the themes and identified specific issues, rather than addressing all questions. Our responses to both Parts reflect working level engagement we have had with Government in our role as Delivery Body and in support of development of REMA.

We look forward to engaging with you further. Should you require further information on any of the points raised in our response please contact Bethany Hanna, Strategy & Policy Manager, EMR Delivery Body, at Bethany.Hanna@nationalgrideso.com.

Yours sincerely

Claire Dykta

Head of Markets

[1] https://www.nationalgrideso.com/future-energy/projects/net-zero-market-reform

[2] Rule 4.4.4: *"The configuration of Generating Units that comprise a CMU must not be changed once that CMU has Prequalified"* and prevents Generating CMUs from changing the assets they entered at prequalification to avoid a termination event.

Appendix 1 Consultation Question Responses

Penalty regime – timelines for calculating non-delivery penalties

Question 1: Do you agree with the proposed changes to the timelines for ESC Volume Re-allocation activities and the Volume Re-allocation window? Are there any unintended consequences of these changes?

Question 2: Do you have any comments on supporting changes to other settlement activities that may be required following the changes to Regulation 41(2)? Do you have any comments on the correction to Regulation references in Rule 10.5?

We welcome the extension of timelines for calculating penalties which would allow for consistency between the Rules and Regulations and support calculation accuracy. We don't envisage any unintended consequences of this change.

Mothballed plant

Question 3: Do you agree with the proposed temporary rule change to operational requirements for Existing Generating CMUs which are mothballed? Does this proposal create any unintended consequences?

We support the proposed extension of the temporary modification of Rule 3.6.1(a), allowing CMUs that have been dormant/mothballed the opportunity to enter the Capacity Market for the 2025 Auction. However, we note that this is an extension to a previous temporary Rule change and would welcome clarity from the Government regarding if the interaction with Satisfactory Performance Day (SPD) proposals from the Phase 1 consultation means it could be further extended for future Auctions.

Further aligning Regulation 50 with policy intent

Question 4: Do you agree with the proposed amendment to Regulation 50 so that it aligns with the policy intent and CM Rules, in that failure to meet EPTs are to be treated in the same ways as failure to meet SPDs across suspension of payments? Does the proposed amendment have any unintended consequences?

We welcome the alignment of Regulation 50 with the policy intent that has already been reflected in the CM Rules.

Changes to the regulations clarifying non-permitted Capacity Market and Contract for Difference participation

Question 5: Do you agree with the proposed amendment to add further detail to Regulation 16 (2) to clarify that that a CMU can only be prequalified where no CfD has been awarded in respect of it, even if the CfD is for a later delivery period, unless the CfD in question has expired or been terminated? Does the proposed amendment have any unintended consequences?

We welcome the proposed changes to clarify the intent of Regulation 16(2) and to better align it with the equivalent provisions under CfD Regulation 14(10).

Addressing challenges faced by batteries in the Capacity Market

Question 6: Do you agree with the proposals that we have put forward to help address barriers faced by storage CMUs in managing battery degradation? Specifically:

- **The introduction of a definition of Permitted Augmentation under Rule 4.4.4; and**
- **Enabling the level of EPT requirement to be appropriately reduced when secondary trading occurs.**

Question 7: Do you foresee any unintended consequences which could arise from the proposals set out in question 6?

Question 8: Do you believe that other supporting changes are required to accommodate the proposals set out in question 6, for example changes to testing arrangements?

Question 9: Noting the considerations outlined in section 6.1 of the consultation, do you have any further comments or concerns regarding the retention of the EPT framework for storage CMUs? Are there any further required changes which have not been identified or considered?

We support the Rules being clarified as proposed to explicitly allow augmentation, as this will ensure a consistent approach is taken by all CMUs. However, note that we do not believe Rule 4.4.4 is currently a barrier to battery augmentation as this is site maintenance rather than reconfiguration of the CMU, and recommend that the Rule amendment should be clear that it is to clarify the current position, rather than being a change.

We do not believe any supporting changes are required and think any requirement to evidence battery augmentation would be overly burdensome compared to other technologies that do not need to evidence routine maintenance further than meeting their performance testing obligations.

Regarding changes to the Extended Performance Test (EPT), we support the proposal to allow the Adjusted Connection Capacity to be adjusted relationally to the amount of capacity secondary traded. We feel it is vital the formula used to adjust for these trades as well as the timing element is clear, especially as EPTs are only required every three years currently. We would welcome the opportunity to work with you to design the new formula as the policy develops.

Government has stated that some respondents to the Phase 1 consultation felt the EPT is too onerous when compared to the Satisfactory Performance Days (SPD) regime. We agree there are differences in the level of evidence required between the two tests but consider that SPDs are too flexible, rather than that EPTs are too onerous. We discuss the performance regime in detail in our response to Part B.

Multi-year agreements for low carbon, low Capex technologies

Question 10: Do you have any further views on the proposed 3-year or 9-year agreement proposals?

Although we recognise that the proposals are examples of prescriptive inputs that mean the CM would no longer be technology neutral, we agree that the specific arrangements being proposed for low-carbon projects will incentivise their investment where the current CM arrangements are a barrier to entry. Given this, we are supportive of the proposal to introduce 9-year Agreements for projects that may not be able to meet the current capex thresholds for 15-year Agreements.

With regards to the 3-year Agreement proposal to support projects with very low capex investment, although we understand the intent, the Delivery Body believe replacement milestones to enable CMUs' progress to be monitored will be required, as the current monitoring relies on financial and construction milestones. Given this, the Delivery Body would welcome clarification of the following aspects:

- Impact on Maximum Obligation Period: If projects which opted for 15-year agreement could not meet the 15-year capex threshold upon assessment of Maximum Obligation Period either during prequalification or when submitting Total Project Spend after obtaining Capacity Agreement, would they still be able to access 9-year agreement if they can meet low-carbon threshold. In other words, is 9-year agreement only accessible when declared at prequalification in the first instance and not able to be transferred to later in the process.
- How the Financial Commitment Milestone (FCM) should be managed if the capex threshold is zero under a 3-year Agreement.

Projects with long build times

Question 11: Do you agree with the proposed introduction of Declared Long Stops, both 12- and 24-month options, to accommodate low carbon projects with long build times in the CM?

The Delivery Body is supportive of the proposal to introduce a Declared Additional (24-month) Long Stop Date which will allow low carbon projects with long build times to participate in the CM. However, we are not clear on the benefits that can be achieved by the 12-month option, given it is already possible for a CMU to delay its Long Stop Date by 12 months.

Additionally, further work is required to understand how these proposed changes to delayed delivery could be taken into account under the parameters setting process. Initial options identified by the EMR Modelling team could require changes to the CM Auction processes (e.g. changes to the algorithm) or risk leading to under or over procurement through changes to the capacity assumed to be delivered. We will continue to work with Government over the winter to further develop detailed policy positions and implementation options.

Question 12: Does the option to declare a (12-month) Long Stop Date provide developers with any benefits versus relying on the existing Long Stop Date process?

Question 13: Does a Declared Additional (24-month) Long Stop Date, Rule 6.7.7 (if applicable) and the existing 120 working days from a Notice of Intention to Terminate provide sufficient time for slippage, and if not, what would be an appropriate amount of time which would need to be considered?

Question 14: Do you foresee any unintended consequences which could arise from the introduction of the declared long stop dates?

We have no material comments at this time on Questions 12-14 but would be interested in the ongoing developments.

Question 15: Do you agree with the proposed eligibility criteria for CMU's seeking to utilise the Declared Additional (24-month) Long Stop?

The Delivery Body agrees with the proposed eligibility criteria for CMUs seeking to utilise the Declared Additional (24-month) Long Stop.

Question 16: Do you agree with the proposed operational conditions for a Declared Additional (24-month) Long Stop?

The Delivery Body agrees with the proposed operational conditions for a Declared Additional (24-month) Long Stop.

Question 17: Do you have views on the relationship between a CMU utilising the Declared Additional (24-month) Long-Stop and its role as Price Maker versus Price Taker in the CM auction(s)?

The Delivery Body believes that CMUs utilising the Declared Additional (24-month) Long-Stop should remain as Price Makers as their participation in the CM will increase Auction liquidity.

Question 18: Are there any further required changes for the implementation of a Declared Additional (24 month) Long-Stop which have not been identified?

As the Modelling team highlighted during the development of this policy proposal, we are currently unconvinced of how effective solutions via the modelling and parameter setting process will be to address the risk of over procurement or under procurement, due to CMUs that use a declared (12-month) long stop date or a declared additional (24 month) long-stop date. While the Modelling team could make adjustments to cover the potential risk, they would need to anticipate or pre-judge the outcome of the Auction, which would be guesswork to some degree, and, if incorrect could lead to a higher T-1 clearing price.

An alternative option is to mitigate the risk of non-delivery due to securing capacity with longer lead times or Long Stop Dates through the Auction itself. For example:

- The target capacity strictly excluded projects with long lead times / additional long stop dates, then the Auction would secure the full target capacity for the Delivery Year.
- If projects with longer lead times / additional long-stop dates are competitively and clearly priced, then these are secured as additional capacity – upside if they deliver on time, but effectively secured 1 – 2 years early (although this may raise questions on fairness).

However, further work is required to assess the impact of this option on Auction dynamics and other consequential impacts. We would be happy to participate in future discussions with Government to understand these risks and develop potential mitigations.

The Delivery Body would also welcome more clarity on a number of aspects, which have been flagged to the Government through working level meetings:

- When a customer utilises the Declared Additional (24-month) Long-Stop, whether the FCM is also subject to change.

- The format and contents of the ITE report provided during prequalification and the level of assessment that the Delivery Body would need to undertake.
- Format of the Directors' declaration and low carbon statement and validation by the Delivery Body.
- Applicability of Rule 6.7.6:
    - Rule 6.7.6 states *"at any time up to eighteen months after the start of the first Delivery Year of the Capacity Agreement, a Capacity Provider may notify the Delivery Body that a Generating Unit forming part of a Prospective Generating CMU has increased its Operational physical capacity such that it is now sufficient to deliver a higher proportion (up to but not exceeding 100 per cent) of its Capacity Obligation, and the Capacity Agreement will take effect from such date with respect to that increased proportion."*
    - If the Declared Long-Stop Date is utilised, whether the timescale of increasing of operational capacity would change to six months after the start of the capacity agreement to maintain the 18 month timeframe after the first Delivery Year under Rule 6.7.6.

Domestic Demand Side Response Participation

Question 19: Do you agree with the proposal for partial redaction of addresses on the CM registers for domestic DSR CMU components?

We support the proposal to remove information that can identify a single domestic address in the Capacity Market Register to avoid the risk of breaching GDPR, whilst maintaining the requirements to provide information to either the Delivery Body or Settlement Body. We agree with the proposed format that will only show the first half of the postcode, although would also support other formats if respondents state a need for more detailed locational data. We also support redaction of the 6-figure grid reference for domestic DSR participants, as this may identify single properties. Regarding implementation, we propose that a common definition of domestic property is agreed, Capacity Participants (CPs) would be required to declare that individual components are domestic properties and provide both the full and redacted address.

If Ofgem approves change CP373 which they are currently consulting on,[3] the responsibility to publish Meter Point Administration Numbers (MPAN) will move from the Delivery Body to the Settlement Body. At present MPANs are not published for domestic units and we believe this redaction should continue because, although the Information Commissioner's Office is unclear on the GDPR status of MPANs without associated usage data, we are aware many industry participants treat MPANs as personal information[4]. Given this, we would recommend the redaction of MPANs for domestic addresses in both the Capacity Market Register and Capacity Market Metering Register (proposed to be introduced under CP373), to ensure consistent treatment in both registers.

Question 20: Do you agree with our proposed changes to component reallocation? If so, what percentage do you propose would be appropriate to set as the new limit?

In general, we agree with the proposal to increase the number of component changes that DSR CMUs are able to make within a Delivery Year. However, as discussed in more detail in regards to introducing DSR GTCs, DSR comprises a number of different technologies and there may be instances where it is appropriate to allow component reallocation as it similar to routine maintenance and, in other cases, it should not be allowed, as it would be similar to a configuration change, which is not permitted for generating CMUs. Until it is possible to distinguish between different DSR types using GTCs, it seems appropriate to continue to allow component reallocation for DSR CMUs and to increase these limits to prevent the ability to reallocate components being a barrier for DSR. However, we recommend that, as part of the wider review of DSR Rules discussed below, Government should consider potentially limiting the types of DSR that can reallocate components.

[3] https://www.ofgem.gov.uk/sites/default/files/2023-11/__Statutory%20Consultation%20on%20Capacity%20Market%20Rule%20change%20proposals%20CP368%2C%20CP369%20and%20CP373_.pdf
[4] https://www.gov.uk/government/publications/electricity-meter-data-collected-through-the-energy-bills-support-scheme-privacy-notice/use-of-electricity-meter-data-collected-through-the-energy-bills-support-scheme-privacy-notice
[3] https://www.ofgem.gov.uk/sites/default/files/docs/2019/07/decision_on_amendments_to_the_capacity_market_rules.pdf

Under the original DSR component reallocation changes introduced in 2019[5], sites do not have to re-test when they do a component reallocation, which means that, in some cases, SPDs were met with the original components and the reallocated components have never been tested. The Delivery Body has a concern that, if the proportional limit was set significantly higher than 10% without triggering an additional DSR test, the reallocated components could go entirely untested through the Delivery Year.

Finally, the current limit placed on component reallocation was originally driven by practical feasibility for the Delivery Body to be able to process a large number of reallocations. Subject to CP373 being approved by Ofgem, the component reallocation process will move to the Settlement Body and so will have a limited impact on the Delivery Body.

Extended Years Criteria

Question 21: Do you agree with the above proposed changes to the Extended Years Criteria? Are there any unintended consequences of these changes?

We believe that the existing Rule 8.3.6B, though somewhat cumbersome, already achieves the proposed policy objective, as the inclusion of "or" between (ii) and (iii) indicates that a Prospective CMU could comprise all new assets (i.e. a New Build), a mix of new and refurbished assets or all refurbished assets, subject to meeting the requirements in (aa) and (bb). This would mean that there is not currently a stipulation requiring a CMU to include a new turbine, where the project is under Rule 8.3.6B(a)(iii), provided it meets the requirements under (aa) and (bb). However, we recognise that the suggested modification may give some clarity by framing the interpretation as an either/or scenario.

We note that removing 'where at least one complete generator or turbine is new;' diminishes the significance of the refurbishment needed to achieve (ii), as it no longer stipulates a significant asset, but expect that application of the Total Project Spend will provide some assurance that a Prospective CMU has not just replaced some small assets in order to comply with Rule 8.3.6B.

Call for evidence on Demand Side Response Generating Technology Classes

Question 22: What are your views on the creation of new GTCs for DSR and which new classes should be created? Please provide evidence to support your response.

We welcome the review of DSR Generating Technology Classes (GTCs), agree with the intent to reduce risks of under delivery and provide below our evidence and suggestions regarding how GTCs could be determined.

The ESO proposes that the new GTCs are based on the technology of underlying CMU components, as set out below, along with some ESO changes to other data collection that will help to future proof the de-rating process. Implementing these changes will require the applicable Rules to be substantially re-written, creating an opportunity to also review of the current provisions for DSR in the CM rules, regulations and related guidance, especially the requirements placed on Unproven DSRs. We believe that this review should take a wider lens to better represent DSR participation in the CM, for example DSR testing (both the DSR test and SPDs) and component reallocation as above.

<u>DSR GTCs change proposal</u>

We propose that DSR GTCs, which are included in prequalification Applications, should be determined in accordance with the underlying technologies of the CMU component:

- **Behind-the-meter generation**: use the GTC corresponding to the behind-the-meter generator. For example, a behind-the-meter diesel reciprocating engine component would be declared with a Generating Technology Class of "Reciprocating Engine". These CMU components would then be subject to fossil fuel emissions declarations if applicable.
- **Load turn-down**: for genuine load turn-down use a GTC corresponding to the expected duration of the load turn down. For example, if an industrial site CMU expects that it could turn down its demand for 2 hours by the stated connection capacity, then it would declare a GTC of "DSR (Duration 2h)". This would require creation of GTCs in Schedule 3 of the CM rules for each DSR duration (in 0.5h

steps up to 12h). The ESO would then calculate de-rating factors for these components using a similar approach to the storage de-rating methodology. Note that this will likely require creation of a new Schedule of the CM rules that addresses Duration Limited DSR de-rating and/or updates to Schedule 3B that describes the current storage de-rating process.

- **Behind-the-meter storage:** use a Duration Limited DSR GTC corresponding to the duration of the behind the meter storage only (any genuine load turn-down DSR should be covered by separate component(s)). For example, a 1MW/2MWh behind-the-meter battery component would be declared as "DSR (Duration 2h)". The reason for declaring as DSR rather than Storage is that testing requirements will need to be different for batteries that are behind the meter, with performance demonstrated relative to a demand baseline. If behind-the-meter storage components are declared as Storage these components will need to meet EPT requirements which may be difficult to demonstrate with an ongoing load at that meter.

The key benefit of this approach is that it will separate out CMU components according to their actual capability to contribute to capacity adequacy during system stress events of different durations. Any approach that does not de-rate load turn-down components according to duration may significantly overestimate the ability of these components to contribute to security of supply and incentivise some CPs to underbid their capacity to manage their risk exposure, as noted in the consultation. Our proposed approach will provide an appropriate replacement for the existing DSR de-rating factor methodology which has significant limitations (see section below).

Another benefit is this would prevent unproven DSR CMUs entering the T-4 auction with undefined components that represent potential sites that they hope to sign up but are not confirmed at that time. This is currently allowed under the CM rules but represents a non-delivery risk as many of these unproven DSR CMUs have their CM agreements terminated or their obligated capacity reduced.

One risk of the proposed approach is that it may provide a barrier to entry for participation for DSR participation in the CM, either via additional administrative effort to provide GTC information or the lower revenues associated with lower de-rating factors for genuine load turn-down components. We believe the administrative barrier is surmountable by providing guidance to CPs on selecting a Duration for the genuine load turn-down components. While the reduced de-rating factors may disincentivise some DSR participation, we believe that it will provide appropriate incentives to participants who are able to deliver effectively.

Another potential risk of this approach is that CPs may not correctly identify their GTC. However, it is likely that the CPs are the only organisation in a reasonable position to provide this information, as they have the best access to knowledge of the individual CMU component details, either directly or via relationships with the owner or operator of the sites. For example, for an aggregator CP that bids in a demand turn-down CMU component on behalf of an industrial site, they will hold the relationship with that industrial site in order to request technical details of their load turn-down capabilities. Guidance should be provided to CPs, particularly on selecting an appropriate duration for Duration Limited DSR GTCs, to help them manage risks associated with self-declaration.

<u>Alternative GTC and de-rating options</u>

For completeness we describe here why some alternative approaches are unsuitable to address this issue.

One alternative approach is to continue having one DSR GTC and use DSR performance data from other GB markets to assign different de-rating factors. The major challenge with keeping GTCs unchanged is that DSR capabilities are highly dependent on the characteristics of the individual CMU component. Using data from another market with a different technology mix may significantly underestimate or overestimate DSR capabilities. DSR in the CM currently contains a mix of behind-the-meter generation, behind-the-meter storage and genuine load turn-down. Applying a single de-rating factor to all of these technology groupings would likely significantly underestimate the capabilities of behind-the-meter generation while overestimating the capability of many load-turn down components.

A second approach could be to change the GTCs as proposed above according to behind-the-meter generation and Duration Limited DSR components, but to use data from other markets to de-rate load-turn down components only. This approach would likely face a similar challenge of providing sufficient evidence that the mix of load turn-down components in the CM are similar enough to those in the market where performance data is being used from. There are significant differences within load-turn down types (e.g. a technology mix with predominantly eVs may behave differently to a technology mix with predominantly industrial sites). Participants in ESO's Demand Flexibility Service (DFS) are currently specifically excluded from holding a CM Agreement, which means there is no overlap between sites providing both services. An additional challenge is that existing DSR markets are relatively immature with limited performance data, particularly on different durations of DSR. For example, the ESO's DFS was brought in for the 2022/23 winter as an enhanced action available to manage security of supply risks. DFS has conducted test and live DFS events to date between 1-1.5h in length, which does not yet provide suitable evidence on the capability of DSR to address a full range of potential CM stress event durations.

A final alternative approach could be to create new load-turn down GTCs according to individual load turn-down technologies. For example, GTCs could be created for smart-charging (non-V2X) electric vehicles, V2X electric vehicles, industrial heat pumps, office air conditioning etc. The key limitation of this approach is in choosing a de-rating approach. Using performance data from other markets to de-rate each GTC faces the challenges noted above. If using a Duration Limited methodology, it would be difficult to identify durations of each GTC given that there will likely be significant variation within each GTC. For example, EVs have significantly different battery duration sizes and usage behaviours across different fleets. As noted above, there is no substitute for the CP's knowledge of usage behaviour and technical capabilities.

<u>Other ESO data collection and future GTC changes</u>

We also propose to capture more granular information on DSR CMUs during prequalification that does not require changes to GTCs and therefore the CM Rules, but that will enable decision making on future changes to DSR the CM. We propose to expand the "Primary Fuel Type" categories of a DSR CMU to the following:

- DSR – Behind-the-meter Generation
- DSR – Behind-the-meter Battery Storage
- DSR – Industrial Load Turn-Down
- DSR – Commercial Load Turn-Down
- DSR – Residential Load Turn-Down

This will enable understanding of developments in DSR providers, without changing how these CMUs are de-rated. This could also complement the information received from the GTC changes proposed above and inform any future changes to GTCs if necessary. To enable future changes, we propose that any drafting of a new DSR de-rating methodology in the CM Rules referenced above includes the option for the ESO to select a technical availability for de-rating CMU components based on either the GTC or the Primary Fuel Type of the underlying DSR. We would also investigate options for collecting Primary Fuel Type information at the component level to enable this approach.

<u>Limitations of current DSR de-rating factor approach</u>

The existing DSR de-rating factor methodology, using non-Balancing Mechanism (non-BM) Short Term Operating Reserve (STOR) availability, was brought in prior to significant DSR participation and now has significant limitations for de-rating DSR CMU components. One significant limitation is that STOR procurement has moved from season-ahead to day-ahead procurement. This means that availability data only reflects those participants that bid into the STOR market day-ahead and does not count assets that are unavailable but that choose not to participate in a day-ahead auction. This means that the DSR de-rating factor is very likely to increase from the 2023 Electricity Capacity Report (ECR) value of 79% in future ECRs, potentially to upwards of 90%, as the past three winters used in the calculation will increasingly reflect day-ahead rather than season-ahead STOR procurement. A second significant limitation is that the non-BM STOR units used are primarily open cycle gas turbine (OCGT) and gas reciprocating engines, which do not represent the full spectrum technologies classed as DSR CMU components in the CM.

Clause 2.3.4b) of the CM rules prescribes that the method of Average Availability of Non-BSC Balancing Services (AABS) should be used for DSR CMUs while clause 2.3.5b) describes the AABS method itself. Therefore the methodology would need to be changed in the CM Rules in order to move to a more suitable DSR de-rating approach.

Decarbonising the Capacity Market

Question 23: Do you have any comments or concerns regarding our proposal to publish the fossil fuel emissions data (as stated above), disclosed in the Fossil Fuel Emissions Declaration on the Capacity Market Register?

Although the Delivery Body are supportive of the aim of the proposal to increase transparency and consistency of fossil fuel emissions information, we note that including Fossil Fuel Emissions data in the Capacity Market Register (CMR) presents challenges that will need to be considered before implementation, including:

- The manual intervention required to transfer information from Exhibit ZA to a digital format and the overall quality of data received on the received Exhibit ZAs.
- Rather than mandating electronic exhibits, Applicants are still able to upload manual exhibit submissions, which suggests practical constraints related to functionality limitations.
- Aggregating emissions data at both Component and CMU levels, considering factors like Fossil Fuel Yearly Emissions and Mixed Fuels itemisation, warrants caution in its interpretation as it would create a misleading impression.
- Whether to integrate this data into the CMR or opting for a separate report requires weighing the benefits of data accessibility against potential challenges associated with data accuracy, manual population, and existing limitations in the current portal functionality.

To facilitate the publishing of emissions data, it would be helpful to address the following questions:

1. Where a CP defers the provision of the Exhibit ZA, would there be a need for Government to know why?
2. Would the formulae used to calculate the Combined Heat and Power (CHP), Carbon Capture Utilisation and Storage (CCUS) or Mixed Fuels be required where the CP does this independently?
3. Would the requirement be applied retrospectively to the emissions data for CPs with existing Agreements, or just for those who submit prequalification Applications (including Exhibit ZA) after the proposal has been implemented?

Appendix 2 Call for Evidence Question Responses

Objectives of the CM

Question 1: To what extent, how and why has the CM been contributing to its intended objectives?

Question 2: How have the different elements of the CM achieved the objectives above?

Question 3: To what extent would you agree that over the last 5 years the CM has achieved these objectives? Please supply as much evidence as possible to support your answer.

Question 4: Have these objectives been equally achieved or has the CM performed better against some objectives than others, and if so, what are the main reasons for your view?

Question 5: Do you agree that the objectives of the CM are still appropriate?

We broadly agree that the CM has achieved its current objectives, but consider that it is difficult to fully assess this, without a counterfactual for comparison. However, evolution in the wider energy landscape and changes in CM participants means that, as set out below against each objective, changes are needed, if are retained in the future.

For our detailed analysis that is relevant to Questions 1 to 5, please refer to the System Adequacy chapter of the ESO's Net Zero Market Reform (NZMR) Phase 4 report.[6]

Security of supply

Question 6: To what extent do existing delivery assurance mechanisms in the CM achieve the CM's objective of ensuring security of supply?

As the nature of CM participants has changed from mostly larger transmission connected generators to a mix with smaller embedded generation, storage and DSR, it is unclear whether the current CM performance regime (particularly testing, stress event definition, notifications, and penalties) will be robust and sufficient to ensure security of supply in the future. Additionally, we have concerns as to whether the CM provides effective enough signals to avoid or reduce the severity of demand control periods. We believe that there are significant grounds for updating the existing CM delivery assurance mechanisms to mitigate potential risks to security of supply as the energy system transitions. Specifically, we recommend that Government should consider suitable eligibility requirements that would provide control room visibility and dispatch of all CMUs, such as by reconsidering the requirement for CMUs to be registered as BMUs or by requiring CMUs to provide equivalent operational data and dispatch capabilities to the BM). We also recommend that Government should initiate a review of CM penalties arrangements to address its potential misalignment with operational and market processes. Taking these actions will help to ensure that the CM delivery assurance mechanisms provide value for money to consumers in mitigating security of supply risks, while avoiding unintended consequences of potential market manipulations.

Control room visibility and dispatch of embedded CMUs

We recommend that Government considers suitable eligibility requirements that would provide control room visibility and dispatch of all CMUs, for example by reconsidering the requirement for CMUs to be registered as BMUs, to manage potential risks to security of supply and consumer costs from lack of control room visibility and dispatch of embedded CMUs. Government's 2021 CM consultation considered this issue and concluded that, while the change would provide benefits to the CM and wider system, further work was required to address barriers to entry and other stakeholder concerns with Balancing Mechanism (BM) participation. We now believe that Government should reconsider this position given emerging risks to security of supply due to lack of visibility of embedded CMUs, as well as progress on initiatives, including code changes, to enable wider access to the BM.

Since the June 2021 consultation published by Government:

- Significant volumes of embedded non-BM capacity with CM agreements have begun to operate in the CM. For example, for the 2023/24 CM delivery year there are embedded CMUs with approx. 6 GW of auction acquired capacity obligations. The actions of these generators are not directly visible to the

[6] https://www.nationalgrideso.com/future-energy/projects/net-zero-market-reform

control room, creating additional uncertainty for control room staff. This additional uncertainty increases the likelihood of expensive balancing actions being taken which may not have been required if this embedded generation were visible. In an extreme case, the lack of visibility may also increase the risk of demand control decisions being taken unnecessarily. Given these embedded generators are receiving CM payments for their contribution to security of supply, we do not believe it is appropriate that they contribute to risks of higher consumer costs and security of supply risks.

- Code modifications have been implemented that enable wider access to the BM. These include Balancing and Settlement Code modifications to allow metering equipment "behind-the-meter" to be used for settlement purposes (P375) and to use a baselining methodology for the purpose of measuring delivery of balancing services rather than a Physical Notification (P376). Both of these changes address issues for sites that have behind-the-meter generation and enable wider participation in the BM.
- Increasing volumes of units have begun to participate in the BM using the ESO's wider access initiatives. This includes over 200 BMUs with over 3 GW maximum power output that have connected via the "small-BMU" process, which enables a BM participant to provide metering data to the ESO via internet protocols rather than physical communication links, significantly reducing the costs of participating. If a CM participant is trusted to deliver in a potential system stress event then that participant should be capable of providing their expected availability and delivered volumes via these protocols.
- Other initiatives are driving towards wider BM participation, including Grid Code mod GC0117 which would align the size threshold across GB at which power stations must be registered as BMUs. This shows the direction of travel towards wider participation. However, it is worth noting that these changes would not be a substitute for a CM requirement for BM participation, due to the significant volumes of embedded generation CMUs that would fall outside of the GC0117 changes.

Review of penalties arrangements

In addition to the requirement for visibility and dispatch of embedded CMUs, we believe there are strong grounds for a comprehensive review of CM penalties arrangements, to minimise impacts on consumer costs and reduce risks to security of supply. Over the last five years, the quantity of Duration Limited storage CMUs has dramatically increased, from around 3GW of CM contracted storage connection capacity in the 2018/19 Delivery Year to nearly 7GW in the 2023/24 Delivery Year. This will further increase to more than 12GW in the 2026/27 Delivery Year (before accounting for storage that secure T-1 auction contracts in that Delivery Year). The current notifications and penalty regime is likely to be severely limited in effectively dispatching storage during a system stress event to avoid or reduce demand control and may increase consumer costs and risks to security of supply. We therefore urge a comprehensive review of current CM penalties arrangements, in combination with control room and market experts.

The current CM penalties regime imposes generally fixed penalty rates[7] on CMUs based on under-delivery against CM contracted obligations, with penalties commencing when the control room enacts demand control for a margin issue. The exact start and end of the penalty period is determined post event by the ESO, and penalties only start if a CM notification has occurred at least 4 hours prior to the start of demand control. This penalty regime is unlikely to provide an effective signal to optimise the use of storage, renewables, interconnectors and duration limited DSR across the horizon of a potential stress event and may reduce the effectiveness of the primary market signals.

For duration limited storage and duration limited DSR resources, control room visibility and dispatch of these duration limited CMUs via the BM is likely to be most effective at managing storage levels and dispatch during very tight periods, helping the control room to avoid or minimise the use of demand control. This underlines the importance of the visibility and dispatch requirement highlighted above. The single starting point of current CM penalty arrangements may incentivise storage and duration limited DSR to bulk dispatch upon issuance of a demand control instruction, potentially creating further operational challenges due to a rapid ramping of power output. While we have not seen a CM stress event to date, recent international experience provides evidence that misaligned dispatch signals for duration limited sources can contribute to operational issues during tight periods. For example, the Californian system operator found that storage capacity dispatched in an undesirable

[7] Adjusted Load Following Capacity Obligation (ALFCO) is used to set penalty rates, including an adjustment factor for the electricity demand during an event as a proportion of peak demand. There are grounds to review this factor given that tight periods have increasingly occurred in shoulder periods and summer periods, as well as during winter peak.

way during a tight period in September 2022, largely due to dispatch rules that require storage to dispatch at a single point.

To address these shortcomings, we recommend that a review of penalties arrangements should seek input from industry and ESO control room experts on mechanisms that incentivise the optimal dispatch of storage, renewables, interconnectors and duration limited DSR resources across the horizon of a potential stress event. Input should then be sought on how CM penalties can provide the best possible signals to incentivise dispatch before, after and during an event. These signals should maintain technology-neutral resource obligation levels, but account for the different physical limits and dispatch processes of different technologies. Possible options could be new penalties arrangements that link penalty rates to BM parameters of units in the period prior to, during, and after a demand control event. This would reduce misalignment between CM penalty signals and BM operation, reducing the risk to consumer load loss and the chances of expensive balancing actions being taken.

Question 7: To what extent has the CM incentivised sufficient investment in capacity to ensure security of electricity supply?

Question 8: What are your views on the resilience of the CM to both longer term and shorter term energy trends?

Cost effectiveness

Question 9: To what extent does the CM reduce the cost of capital and investment risks for CM participants?

Question 10: To what extent would you agree with the above statement that low clearing prices signal the scheme’s cost effectiveness when compared to the value of lost load?

The ESO’s NZMR work raises concerns that, with system change and market reforms, the CM might not be able to provide consumers value for money in securing efficient investment in the right kind of resources that can ensure cost effective system security and reduce carbon emissions. REMA decisions and implementation of consequent reforms should inform choices on CM reform/replacement. We have identified alternatives to the CM that could better meet objectives in a zero carbon renewables-based system, but in the shorter term before REMA has concluded, we agree changes could be made to improve the CM design to better meet the objectives, as identified in our work on electricity market reform.[8]

Question 11: What are your views on the effectiveness of the controls and delivery assurance frameworks within the CM to mitigate against gaming and the potential abuse of market power?

The current CM governance and delivery framework relies on an “honesty” system whereby Directors provide an undertaking that the information provided at prequalification is true and accurate, Independent Technical Experts validate performance against Agreement milestones, and CPs are required to actively notify the Delivery Body of situations, such as a termination event occurring. Checks undertaken by the Delivery Body are specified in the Rules.

The Delivery Body would further note that, with regards to the Auction process, there are limitations with the current safeguards, which require a Bidder to comply with the formalities referred to under Rule 5.3.2(a), in order to become an authorised individual. Additionally, under the CM systems, a Bidder can only have four authorised individuals. However, although these arrangements enable us to identify the details used to place bids in the Auctions, we are unable to determine if the named individual was the one that used them or if collusion was happening outside the Auction system (e.g. phone calls or being physically located together).

The Delivery Body would welcome the opportunity to work with Government to review the current governance framework in order to:

- Identify specific areas of concern, where the Delivery Body’s checks during the lifecycle of an Agreement may not uncover an issue, without actively looking for them.
- Assess the extent that the current level of assurance checks remains appropriate, balanced against the increased administrative burden for delivery partners and participants if this becomes a more granular process.

[8] https://www.nationalgrideso.com/future-energy/projects/net-zero-market-reform

- Check whether any system changes could also mitigate risks of gaming or market power abuse.

Additionally, some elements of the CM Rules and the framework may introduce risks, where they have not been updated to reflect the changing technologies that are entering the CM. For example, our understanding is that the original intent of the Confirmation of Entry process was to enable projects with significant construction to exit the Auction, if they became aware that the project would not be deliverable within the timeframes. However, as the process is available to all new build, there is a risk that rapid build CMUs could elect to exit the T-1 Auction through this process, meaning less capacity than anticipated will participate.

Avoid unintended consequences

Question 12: Are there distortions in the interaction of the various markets (wholesale, ancillary, CM), or their charging arrangements, which impact the effectiveness of the CM?

Related to the previous security of supply point, there is a potentially significant distortion where CMUs who are not BMUs can either deliberately manipulate, or just by lack of visibility to the control room increase the uncertainty in the BM, increasing costs for consumers and makes decision making more difficult for the control room during tight periods.

Although we agree there exists potential to improve the CM design in the shorter-term, REMA decisions and implementation of consequent reforms should inform choices on CM reform/replacement and how to do this. Additionally, it is necessary to evaluate the market failures that the CM is designed to address and how they are expected to change in future and what this might mean for the CM. The ESO's NZMR work raises concerns that, with system change and market reforms, the CM might not be able to provide consumers value for money in securing efficient investment in the right kind of resources that can ensure cost effective system security and reduce carbon emissions. In our NZMR report, we have identified alternatives to the CM that we think could better meet objectives in a zero carbon renewables-based system.

Additionally, as is also discussed in our NZMR work, there is evidence that the CM suppresses wholesale scarcity prices, and that research has also shown that CPs are not passing through full benefits to consumers.

Question 13: What are your views on the effectiveness and operation of the existing rules within the CM to support the transition to net zero? (You may want to consider emissions limits, and barriers faced by low carbon technology in accessing the CM). Please provide evidence to justify your answer.

Question 14: Are there any other improvements to the CM that would help support the transition to net zero? Please provide evidence to justify your answer.

The CM is designed to be technology neutral, which inevitably means that it does not specifically support the transition to net zero. When assessing whether to make changes to specifically enable participation of low carbon technologies, the ESO's NZMR programme has identified some factors that should be considered:

- Capacity gap reports indicate that existing gas plant will need life extensions and additional new gas plant may be needed, which should continue to compete directly with low carbon resources in the CM. It is important to ensure that net zero objectives do not result in unabated gas being inadvertently pushed out of the market by resources that do not have the capabilities (e.g. sustained response) needed by the system during the transition to maintain system security.
- The main focus for new investment to support system security needs to be on low carbon sustained response technologies, which have their own specific support mechanisms (e.g. cluster sequencing for CCUS). Providing specific provision for them in the CM risks these projects benefiting from double subsidies, which would ultimately be paid for by consumers.
- Improving demand and supply matching in the wholesale energy market – through market design reforms and implementing stronger demand reduction policies could reduce carbon more cost effectively in the power system.

Governance arrangements

Question 15: To what extent do the current institutional arrangements support an effective change process? Please provide suggestions on how issues with governance arrangements can be addressed and evidence to support your views.

As an active participant on CMAG, the Delivery Body believes that its creation has greatly improved the change process by providing a central forum for proposed changes to the CM Rules to be raised, challenged and developed by expert members, leading to recommendations to support policy makers to make decisions. The Delivery Body also notes that over 2023 there has been an increase in clarity around the division of responsibilities between Government and Ofgem, which will help CMAG focus on issues that fall within their remit. However, a reminder of the policy intent that underpin the CM, and the extent that this should or should not change to reflect evolution of participants and the energy landscape since the CM was introduced, would benefit the industry.

Question 16: To what extent do the defined and allocated roles and responsibilities support effective administration and delivery of the annual CM prequalification, delivery, and payment processes? Please provide suggestions on how any issues can be addressed and evidence to support your views.

The Delivery Body believe that the allocation of roles and responsibilities continues to be effective, with clearly responsible parties for prequalification and management of Auctions and CM Agreements, and payments. However, we recognise that there may be operational activities that could be improved by better aligning them with the responsible delivery partner to deliver efficiency and enhanced customer experience and will continue to work with ESC and EMRS to explore these and assess the benefit of potential changes.

Question 17: Please provide any suggestions you have for improving the management of fraud and error risk in the CM.

As identified under Question 11, the current governance framework relies on CPs providing true and accurate information, including updates where circumstances change, and the Delivery Body has seen an increase in instances where CPs are seeking to manage situations that may not have been envisioned at the time the Rules were drafted. The Delivery Body notes that there are several aspects of the governance framework that could be enhanced to reduce fraud risk:

- Tighten the qualification requirements for an ITE to ensure they are able to demonstrate they have sufficient expertise to provide confirmation the CP has achieved a milestone on a consistent basis. We recognise the challenge with identifying sufficient ITEs if the requirements were too narrow, but believe the current arrangements provide very limited assurance of expertise.
- Include explicit provision for the Delivery Body to be able to address issues they observe, such as if they become aware of something that could lead to a termination event that the CP has not notified us about (the CP is required to notify the Delivery Body under Rule 6.10.1).

With regards to error risk, some key improvements would be:

- Delivery Body errors – allowing the ability to reverse administrative errors outside of the escalation processes set out in Regulation 69. In particular, there is not currently an explicit process to address the rare instances where the Delivery Body incorrectly prequalified an Applicant, resulting in an ineligible CMU having an Agreement. Which are currently addressed under Rule 6.10.1(o).
- Applicant errors – enabling dialogue between Applicants and the Delivery Body during the prequalification application and assessment process and when monitoring delivery of Agreements would enable minor errors to be efficiently addressed. However, as noted in response to the Technopolis evaluation, this would need to be well defined to avoid risk of abuse.

The Delivery Body would welcome the opportunity to explore these issues with Government in more detail, including identifying potential improvements to the Rules and systems.

Secondary trading

Question 18: Considering new, higher risk technologies coming into the CM, does the continued policy intention for secondary trading set out above remain appropriate? If not, why not? Please explain your reasoning.

Question 19: Are there any further issues on secondary trading that you feel cannot be addressed through CMAG and Ofgem, as they may require significant policy, rules or regulation change? If so, what are these issues and why do you feel they need to be addressed? Please explain your reasoning.

We are supportive of changes to secondary trading, where the changes would then enable the performance regime to be tightened. This interaction could be supported by insights from other jurisdictions such as ISO New

England[9] and PJM[10] in the United States. However, although we agree that secondary trading has a role in helping CPs to manage their risk if they are unable to meet their obligations, and that this might be different for newer technologies, we do not think that the goal of secondary trading (or any other Rule changes) to be to completely de-risk the CM for participants. Instead, we support greater clarity from Government about the scope of secondary trading's role in risk management and, by extension, its limitations.

We would also like to highlight the interaction between secondary trading and other aspects of the Rules that may also merit review, in particular:

- Rule 4.4.4 – this Rule prevents Generating CMUs from changing their configuration after they have prequalified. Changes to this Rule to enable CMUs to manage their risk, would change the CM from an asset-based to a commodity-based regime.
- Terminations – clarity from Government and Ofgem about scenarios where terminations are an acceptable outcome under the CM would help CMUs to better understand the risk associated with CM participation and make more informed decisions about their participation.

The Delivery Body supports Technopolis' recommendation to consider centralising secondary trades in order to increase transparency and support smaller CP participation. However, rather using a central market platform, it would be possible to use of a simple tool, such as central register so CPs can identify Acceptable Transferees capacity that they could trade to. The Delivery Body would be happy to support Government with exploring this idea in more detail.

Views on the evaluation

Question 20: What are your views on the findings of the Technopolis evaluation and independent research?

Question 21: Do you have any further views based on your experience of the CM's performance, particularly in the last five years but also since its implementation, that we should consider in the context of the Ten-year Review?

Question 22: Please provide suggestions on how any issues raised in the report can be addressed and provide evidence to support your views.

Regarding the suggestion that the Delivery Body review the prequalification process, we note there are improvements being developed or already implemented to address concerns raised by surveyed stakeholders:

- In 2022, Ofgem introduced Evergreen prequalification changes that enable Applicants to re-use specific exhibits, declarations and other information that was previously part of a successful Application.
- The Delivery Body's new Portal will be launched next year, in time for it to be used for prequalification for the 2025 Auction.
- In 2021, DESNZ amended Regulation 69 to enable the Delivery Body to take into account information or evidence that it considers to be a "non-material error or omission" as part of the Tier 1 disputes process.

We have concerns with the suggestion that the Delivery Body should be more lenient towards minor errors during the assessment process, as, although we agree that the changes to Regulation 69 have been positive overall, our experience has been that "non-material" is subjective and some Applicants have argued that omissions we would consider significant for the robustness of the prequalification process, such as correctly signed Directors' certificates, are non-material. Giving the Delivery Body flexibility in how it assesses compliance with the Rules could create a situation where Applicants take less care when preparing their Application on the assumption that the Delivery Body will still prequalify them.

However, we are supportive of the recommendation that the Delivery Body is able to engage with CPs during the prequalification process, although the scope of this would need to be well-defined, to avoid the Delivery Body replacing Applicants undertaking their own due diligence and, if necessary, procuring Legal or consultancy

[9] https://www.iso-ne.com/about/what-we-do/three-roles/administering-markets
[10] https://www.pjm.com/markets-and-operations/rpm

support. Clear definition would also avoid any perceptions of favourable treatment for those who have the capacity to be highly engaged, rather than potentially smaller Applicants that have more limited resources.

Although not identified in the findings, the Delivery Body is not supportive of the suggestion from some surveyed stakeholders that it would be more efficient if the requirement for ITEs was removed, as they have a role in providing assurance that CPs have met their milestones. We recognise there is significant variation in the quality and detail provided in ITE reports and would recommend stronger governance around their qualifications, the evidence they provide and the consequences if they are found to have given inaccurate information.