Department for Energy Security & Net Zero

Capacity Market 2023 Consultation: Government response

Strengthening security of supply and alignment with net zero

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Executive summary

Between 9 January and 3 March 2023, government consulted on a range of policy proposals to improve delivery assurance in the Capacity Market (CM), and better align the scheme with net zero. A total of 65 responses were received, primarily from industry stakeholders, but representative bodies, research and delivery organisations were also represented. Most of the proposals were broadly supported by respondents, while others provided useful feedback which the government will reflect on.

The government intends to take forward the proposals in two phases. Phase 1 includes proposals to be implemented prior to the 2024 CM auctions, and phase 2 includes proposals requiring further analysis and development, with a view to implement from 2024 at the earliest.

The phase 1 proposals will proceed with most of the changes as proposed, with alterations to the mothballed plant proposal in light of the responses to the Satisfactory Performance Days proposal. In summary, the proposals intended for implementation before the 2024 CM auctions include:

- Proposals to reform the way in which **Connection Capacity** is determined, to ensure it better reflects export capability;
- Extending the temporary arrangements introduced in 2022 to remove barriers to **mothballed plant** entering the CM. This will enable existing CMU applicants who cannot provide settlement data from the 24 months prior to the end of the Prequalification Window to use older data. The government will continue to do further analysis and development on an enduring solution as part of phase 2.
- Proposed changes to the **timelines for calculating non-delivery penalties** by amending the current 21 working day deadline to allow up to 35 working days. This is to ensure that the Electricity Settlement Company (ESC) has sufficient time to receive relevant data so it can accurately calculate penalties for Capacity Providers and issue the associated invoices;
- Proposed **clarification of the auction clearing mechanics**, to ensure that the legislation more clearly reflects policy intent and implementation;
- Proposed changes to reduce the administrative burden resulting from requirements on the Secretary of State to determine whether capacity auctions need to be held;
- Proposed changes to **amend the definition of the Contracts for Difference (CfD) Transfer Notice**, to ensure the process works in practice by enabling eligible capacity providers to bid in a CfD allocation round;
- Proposed changes to end the requirement for **Independent Technical Expert reports** when Capacity Providers make material changes to construction plans or material changes in dates to construction milestones. This is intended to reduce the administrative burden and cost for Capacity Providers; and
- Proposed changes to **temporarily delay the requirement for Fossil Fuel Emissions Declaration verification** from prequalification in 2023 to 2024, with any verification

carried out in 2023 also being valid in 2024. This will mitigate the risk of the low number of accredited Independent Emission Verifiers (IEV) available at present, which may cause applicants to fail to prequalify during the 2023 window if verifications are not completed in time.

In phase 2, the government intends to undertake further analysis and development on the remaining proposals prior to taking a final decision on implementation. These include:

- Proposal to reorganise the **Satisfactory Performance Days** process around three distinct pass windows over the course of the winter of the Delivery Year;
- Proposal to **strengthen the non-delivery penalty regime** by changing the figure used in calculating the penalty rate from 1/24 to 1/4;
- Proposals to reduce the **emissions intensity limit** applicable to new build plants from 1 October 2034;
- Proposal to enable **low carbon capacity with low capital expenditure to access multi-year agreements** of up to three years without being required to meet capital expenditure thresholds;
- Proposal to update the **reference cost levels** for the CM capital expenditure thresholds;
- Proposal to **introduce a new 9-year threshold** as a mid-point between the existing 3- and 15-year; and
- Proposal to amend the definition of '**Total Project Spend**' such that the window to account for capital expenditure costs for refurbishing units would be aligned with that of new build units.

Context

Background

Since its introduction in 2014, the Capacity Market (CM) has ensured that Great Britain maintains and brings forward sufficient capacity to deliver secure supplies of electricity to power our homes, businesses and public services.

However, during this time the policy, economic and technological landscape in which the CM operates have shifted significantly. The decarbonisation, driven by the government's Net Zero Strategy, is accelerating the transition away from oil and gas by increasing the deployment of renewables. In 2021, the government announced a commitment to achieve a decarbonised power sector by 2035, subject to security of supply. To support this, government has announced ambitions targets for offshore wind and solar and committed to annual Contracts for Difference (CfD) auctions.

This change has happened in the context of global events which have impacted on energy security. The easing of Covid-19 restrictions across the globe contributed to a surge in wholesale gas prices and in turn caused a significant increase in wholesale electricity prices. This trend was exacerbated in February 2022 when Russia illegally invaded Ukraine, which led to higher gas and electricity prices across Europe and increased concerns about energy security for winter 2022/23 and beyond.

In April 2022, the British Energy Security Strategy announced the government's intention to undertake a longer-term Review of Electricity Market Arrangements (REMA). This is a major review into Britain's electricity market design to radically enhance energy security and to help deliver the government's world-leading climate targets whilst reducing exposure to international gas markets. The initial consultation included options for optimising the CM, and for alternative policy mechanisms for ensuring capacity adequacy. The summary of responses to the consultation was published in March 2023 and outlined several options not being taken forward into the next round of assessment.

In March 2023, the government published Powering Up Britain, which sets out the government's approach to energy security and net zero, and acts as an introduction to the complementary Powering Up Britain: Energy Security Plan and Powering Up Britain: Net Zero Growth Plan. These policy papers outline how the government plans to secure our energy system by ensuring a resilient and reliable supply, increase our energy efficiency, and bring bills down through decisive actions to increase Great Britain's low carbon domestic electricity supply. They also outline plans to reduce our reliance on fossil fuels for heating and transport and continue UK leadership in securing the economic benefits of the energy transition, including through major investment in Carbon Capture, Usage and Storage (CCUS). The government has continued to work closely with Ofgem, the gas and electricity system operators, and all relevant stakeholders to ensure the government has the maximum tools available to secure our energy supply for winter 2023/24.

These factors have strengthened the rationale for taking action to reform key aspects of the CM design, to ensure it continues to function effectively in a changing world. For this reason, in

January launched a consultation on range of proposals that are aimed at strengthening security of supply by improving assurance that capacity secured at auction will deliver when needed in times of system stress, aligning with the achievement of net zero targets and improving the way the CM operates.

Overview of consultation proposals

The consultation posed 35 questions, which sought views on a wide range of proposals which are set out below:

Strengthen security of supply

- **Reorganising the Satisfactory Performance Days** (SPD) process around three distinct pass windows over the course of the winter of the Delivery Year. The intent was to provide delivery assurance by ensuring regular checks on the availability and capability of Capacity Market Units (CMUs). The government also asked for evidence on some of the challenges Capacity Providers have raised regarding the ability of storage CMUs to meet the requirements of the Extended Performance Test (EPT).
- **Reforming the way Connection capacity** is assessed in the CM. The intent was to ensure a CMU's connection capacity is reflective of the capacity it can credibly export to the transmission or distribution network and to simplify the process for determining connection capacity.
- **Removing barriers to mothballed plants prequalifying** in the CM by amending the rules relating to provision of evidence of Previous Settlement Performance for existing CMUs.
- **Strengthening the non-delivery penalty regime** by changing the figure used in calculating the penalty rate from 1/24 to 1/4. The intent was to send a clear signal to Capacity Providers about the importance of delivery during a system stress event. The government also proposed to **amend the timeline for issuing non-delivery penalties**. The intent was to ensure that the Electricity Settlement Company (ESC) has sufficient time to receive relevant data so it can accurately calculate penalties for Capacity Providers and issue the associated invoices.

Aligning the CM with net zero

- **Reducing the emissions intensity limit applicable to new build CMUs from 1 October 2034**. The intent was to end the inconsistency between the government's decarbonisation commitments and the 15-year CM agreements available for unabated fossil fuel generation.
- **Enabling low carbon capacity with low capital expenditure to access multi-year agreements of up to three years** without being required to meet capital expenditure thresholds. This was intended to incentivise increased participation in the CM for low carbon flexible capacity by removing participation barriers.

- **Updating the reference cost levels for the CM capital expenditure thresholds**. This was intended to ensure these thresholds remain appropriate for the capacity mix which may be seen in the CM during the transition to a net zero power system.
- **Introducing a new 9-year threshold** as a mid-point between the existing 3- and 15-year. The aim of this change is to support the potential wide range of low carbon projects that may seek to participate in the CM in future.
- **Amending the definition of 'Total Project Spend'** such that the window to account for capital expenditure costs for Refurbishing CMUs would be aligned with that of new build CMUs. The aim of this change is to enable refurbishing capacity to capture their full capital expenditure costs in recognition of the fact that some refurbishments are in practice as complex and intensive as building new capacity.

Additional improvements to the CM

- **Clarifying auction clearing mechanics** which was intended to ensure that the legislation more clearly reflects policy intent and implementation.
- **Reducing the administrative burden resulting from requirements on the Secretary of State** to determine whether capacity auctions need to be held.
- **Amending the existing route for certain projects to exit the CM in order to become eligible to bid in a CfD allocation round,** which was intended to ensure the process works in practice.
- **Ending the requirement for Independent Technical Expert (ITE) reports when Capacity Providers make** material changes to construction plans or material changes in dates to construction milestones. This was intended to reduce the administrative burden and cost for Capacity Providers.
- **Temporarily delaying the requirement for Fossil Fuel Emissions Declaration verification from prequalification 2023 to 2024**, with any verification carried out in 2023 also being valid in 2024. The intention of this temporary Rule change is to mitigate the risk of the low number of accredited Independent Emission Verifiers (IEV) available at present, which could cause applicants to fail to prequalify during the 2023 window if verifications are not completed in time, thereby potentially impacting on auction liquidity and security of supply.

The consultation also invited views on:

- **Enabling CMUs to leave their multi-year agreements early to decarbonise,** subject to security of supply considerations. High carbon CMUs risk being locked into their long-term CM agreements even if able to decarbonise. Creating managed exit pathways could accelerate the decarbonisation of capacity in the CM.
- Evaluating the role government energy policy has in supporting **projects with long build times** and the relationship between the CM and wider government support for large-scale long-duration electricity storage (LLES)**.**

The summary of responses outlines the feedback received and sets out the government's policy response.

Responses to the consultation

The consultation was published online and ran between 9 January 2023 and 3 March 2023. The consultation received 65 responses in total; these responses were submitted through an online portal (Citizen Space – 18 responses) and by email (47 responses).

The 65 responses were received from a range of stakeholders, as follows:

- **Industry**, including capacity providers: 41 respondents (63%)
- **Public and commercial representation**, including trade associations, industry bodies and charities: 17 respondents (26%)
- **Research**, including think tanks: 3 respondents (5%)
- **Delivery**, including government delivery partners: 3 respondents (5%)
- **Finance**, including investment firms and organisations: 1 respondent (2%)

The government is grateful to all respondents to the consultation for taking the time to submit their views.

In summarising the responses received to each question, “most” or “many” indicates more than 70%, “the majority” indicates a view was held by more than 50% of respondents to that question, “some” between 30% and 70%, and “a few” for less than 30% of respondents who expressed an opinion. When considering this summary of responses, please also note that:

- Due to the large volume of responses received, this summary does not seek to exhaustively capture all views expressed, but rather to summarise the prevalent themes and particularly notable points of feedback within responses;
- Respondents used either an online response form or sent in their responses by letter; and
- Not all responses answered every question, or addressed specific questions, and the number of responses each question received varied significantly. The government have noted the number of responses each question received; this number excludes those who stated they had no opinion or comment to give on the question.

The government ran several stakeholder events during the consultation period to support respondents in developing their responses; views expressed solely during these events are not captured here but were factored into our decisions on implementation.

Summary of Responses

The government is grateful to every respondent for taking the time to submit their views to this consultation. The proposals were broadly supported by respondents, while others provided useful feedback which the government will reflect on. Specifically:

- The majority of respondents agreed with our proposal to enable Capacity Providers to determine a CMU’s connection capacity on the basis of Transmission Entry Capacity (TEC), Maximum Export Capacity (MEC), or Average Output. When asked about any unintended consequences, a majority felt that the approach was sensible, and some responses felt that the proposed change would ensure that a CMU’s capacity more accurately reflects their ability to deliver during times of system stress. Respondents that did not support the proposal raised concerns over impacts on demand for connection agreements and incentives for co-location.

- Respondents to the proposal to remove barriers to mothballed plants from prequalifying in the CM were mixed. Supportive responses felt that the delivery assurance put forward in the proposal was enough to enable mothballed plants to be permitted to enter the CM. Other responses felt that a different framework for delivery assurance should be implemented. Those that disagreed with the proposal suggested that enabling mothballed plants to participate in the CM would go against the principle of encouraging new build capacity.

- Most respondents welcomed our proposal to introduce lower emission limits for new and Refurbishing CMUs from 2035, with many recognising that our proposal was important for incentivising decarbonisation. Some agreed with the overall direction of travel but argued that our proposals were not ambitious enough and suggested that CCUS and hydrogen maintain a link to fossil fuels and lock in upstream emissions, as well as that if the government did proceed with the proposal, it should include a review clause to react appropriately should new low carbon technologies be developed.

- The majority of respondents were supportive of our proposal to allow low Capex, low carbon CMU’s to be eligible for multi-year agreements, with low carbon technologies such as DSR offered 3-year agreements with no Capex threshold (which meet the post 2034/35 emission intensity limit). Almost half of the responses expressed support, though suggested alternatives included extending the proposal to include refurbishing low-carbon CMUs.

- Responses on the impacts of the emission limits proposal may have on investment in transitional pathways to decarbonisation were mixed. Almost a third of respondents suggested that the CM alone is not sufficient to drive the necessary investment in transitional technology. Others raised concerns about the CM supporting unproven technologies which may not come to fruition or may distort the market. A few stakeholders also suggested that the preclusion of low hydrogen blends may stymie the development of low carbon hydrogen production and suggested that a gradual increase of hydrogen content in blends may be the most effective way to stimulate hydrogen production.

- Most respondents supported changes to the definition of Total Project Spend to extend the scope of the existing permitted period for Capex in respect of new build CMUs to include Refurbishing CMUs. Those responses which caveated their support urged the government to ensure that the proposal does not capture work capacity providers would have undertaken anyway, without requiring CM support. Other responses raised the need to ensure the measure does not enable the refurbishment of existing fossil fuel generation sites without a clear decarbonisation plan in place.

- Most respondents urged the government to continue with the development of the proposal to allow projects with long build times to participate in the CM. Supportive responses highlighted the role long duration electricity storage must play in delivering energy security and delivery of net zero targets. Of the respondents who did not support the proposal, they suggested that the CM is not an appropriate mechanism to support projects with long build times.

- Many respondents welcomed our phased approach to implementing the requirement that Fossil Fuel Emission Declarations (FFEDs) be independently verified, with any verifications completed in 2023 remaining valid for the 2024 prequalification window. Those that supported our approach recognised it mitigated against the risk of Capacity Providers being unable to get verification due to a lack of IEVs and avoided penalising providers who had already secured verification while ensuring security of supply. Some responses highlighted concerns and cited their own experience about the capacity and availability of IEVs. Some respondents, while welcoming the proposal, questioned why the Environment Agency could not act as the verification body, as they already monitor emissions. Other responses raised broader concerns about the CM and its pathway to decarbonisation and net zero.

Next steps

Following the conclusion of the consultation, the government aims to take forward the proposals in two phases:

Phase 1: Proposals intended for implementation before the 2024 Capacity Market Auctions

The government intends to implement the following proposals so that they are in place in time for the 2024 CM Auctions. The proposals will be implemented by making amendments to the Capacity Market Rules and Electricity Capacity Regulations 2014, subject to Parliamentary time:

- Proposals to reform the way in which Connection Capacity is determined, to ensure it better reflects export capability *(Section 2.3 of the consultation)*;
- Proposal to remove barriers to mothballed plant. The temporary arrangements introduced in 2022 will be extended for one year, to enable applicants who cannot provide settlement data from the 24 months prior to the end of the Prequalification Window to use older data *(Section 2.4 of the consultation)*;
- Proposed changes to the timelines for calculating non-delivery penalties by amending the current 21 working day deadline to allow up to 35 working days *(Section 2.5.3 of the consultation)*;
- Proposed clarification of the auction clearing mechanics (*Section 4.2 in the consultation*);
- Proposed changes to reduce the administrative burden resulting from requirements on the Secretary of State in determining whether capacity auctions need to be held (*Section 4.3 in the consultation*);
- Proposed changes to amend the definition of the CfD Transfer Notice to enable eligible Capacity Providers to bid in a CfD allocation round (*Section 4.4 in the consultation*);
- Proposed changes to end the requirement for ITEreports when Capacity Providers make material changes to construction plans or material changes in dates to construction milestones (*Section 4.5 in the consultation*); and

- Proposed changes to temporarily delay the requirement for FFEDverification from prequalification in 2023 to 2024, with any verification carried out in 2023 also being valid in 2024 (*Section 4.6 in the consultation*).

Phase 2: Proposals requiring further analysis and development

The government intends to undertake a further phase of analysis and development on the remaining proposals prior to taking a final decision on implementation. These include:

- Proposal to reorganise the SPD process around three distinct pass windows over the course of the winter of the Delivery Year (*Section 2.2 of the consultation*). The government will also continue to do further analysis and development on an enduring solution for mothballed plant *(Section 2.4 of the consultation)*;
- Proposal to strengthen the non-delivery penalty regime by changing the figure used in calculating the penalty rate from 1/24 to 1/4 (*Section 2.5 of the consultation*);
- Proposals to reduce the emissions intensity limit applicable to new build plants from 1 October 2034 (*Section 3.2 of the consultation*);
- Proposal to enable low carbon capacity with low capital expenditure to access multi-year agreements of up to three years without being required to meet capital expenditure thresholds (*Section 3.4 of the consultation*);
- Proposal to update the reference cost levels for the CM capital expenditure thresholds (*Section 3.5.2 of the consultation*);
- Proposal to introduce a new 9-year threshold as a mid-point between the existing 3- and 15-year (*Section 3.5.2 of the consultation*); and
- Proposed changes to amend the definition of 'Total Project Spend' such that the window to account for capital expenditure costs for refurbishing units would be aligned with that of new build units (*Section 3.5.3 of the consultation*).

Further analysis and development will consider stakeholder feedback received in this consultation and the impacts on security of supply. Implementation will also be subject to ongoing compliance with the UK's new domestic subsidy control regime, which was established under the Subsidy Control Act 2022. As part of this, the government will consider if a further consultation is needed to seek additional stakeholder views on these proposals.

The government also intends to continue the development of the decarbonisation of existing CMUs proposal alongside REMA, and to continue to explore options for addressing the issues faced by projects with long build times.

Review of Electricity Market Arrangements (REMA)

In March 2023, a Summary of Responses to the 2022 REMA consultation was published. The government has decided to retain the Optimised CM and Centralised Reliability Options, and further investigate their benefits and risks. The government has also decided to retain the Strategic Reserve and Targeted Tender/Payment as time-limited transitional and emergency measures only (not as primary mechanisms for capacity adequacy), and to carry out additional work to evaluate their potential benefits and risks of using them in this capacity. The government plans to publish a second consultation in 2023 where decisions will be taken on shorter-term reforms more quickly where it is viable to do so.

The government will continue to ensure that future changes to the CM are considered within the context of REMA's emerging direction of policy in relation to both the CM and wider energy markets.

Strengthening Security of Supply

This chapter summarises Section 2 of the consultation (Questions 1 to 7), which considered a range of issues and options related to delivery assurance within the Capacity Market.

Satisfactory Performance Days

Questions 1 and 2 explored changes to the testing framework for Capacity Providers (see Section 2.2 of the consultation).

Question 1 consulted on proposals to reorganise the Satisfactory Performance Days (SPD) framework, which acts to provide delivery assurance during a Delivery Year. Under these proposals, Capacity providers would continue to be required to demonstrate three SPDs over the course of winter in the Delivery Year, however the timing of these SPDs would occur during three distinct pass windows, and the risk of suspension and termination starts earlier. The proposed pass windows over winter would be intended to improve delivery assurance ahead of and during the most challenging months of the Delivery Year, to better support security of supply and maximise value for consumers.

Question 2 sought evidence from stakeholders on potential barriers to entry for storage CMUs resulting from performance and duration testing requirements and asked for views on potential solutions to address these barriers. In particular, this question explored the role of the Extended Performance Testing (EPT) framework, and impacts this may have on storage CMUs and CMUs with at least one Demand Side Response (DSR) component which contains a storage facility.

Summary of responses

Question 1 received 51 responses. Of these, seven responses expressed support, eight agreed with the principle of the proposal but had areas where they recommended further consideration, and 31 responses did not agree with the proposal. A further five responses did not state whether they supported the proposal but raised some potential unintended consequences of the change.

Of the seven supportive responses, some felt that strengthening the SPD framework as proposed would better support winter security of supply. Others expressed the view that a stronger SPD testing regime would provide additional protection against paying Capacity Providers who may be unavailable during challenging winter months at added costs to consumers. Of the eight that agreed with the proposal in principle but raised other considerations, most suggested alternative SPD windows to those outlined in the consultation and raised similar concerns of unintended consequences as the non-supportive responses detailed below.

31 respondents opposed the proposal. While many recognised the policy intent behind the proposal, the majority raised concerns over the prescriptive nature of the proposed SPD windows and perceived the proposed framework for missed SPDs to be overly punitive. Six responses did not agree with the policy intent. These respondents did not perceive a need to strengthen delivery assurance and felt that current arrangements remained appropriate given the lack of system stress events. Some stakeholders considered SPDs as a poor measure of a CMU's availability and suggested that they may not accurately reflect the ability to deliver during times of system stress. One stakeholder considered that the risk of non-availability was addressed through derating factors, allowing for this risk to be accounted for in auction target setting, but felt that enhanced monitoring of SPDs did not enable responsive capacity procurement within delivery years. In addition, a few stakeholders felt that monitoring of CMU availability is beyond the original intent of the Capacity Market. A few respondents asked for further evidence on the need to implement such a change, while a few also felt that a more detailed investigation of the potential impacts should be explored before implementation.

Many responses did not agree with the timings of the proposed SPD windows, with strong consensus amongst non-supportive responses that the proposed SPD windows were too prescriptive and may not reflect the needs of the electricity system. While the proposed change to SPDs is intended to provide delivery assurance ahead of the most challenging winter months, some stakeholders challenged whether the proposed windows would achieve this and felt that they could have a distortive impact if misaligned to market signals. Some stakeholders noted that warm weather conditions in October may reduce demand levels. These respondents felt that wider electricity market signals would be expected to reflect this reduced demand, but that assets could still be incentivised to run for the purposes of achieving their SPD window. A few stakeholders felt this could in-turn also lead to unnecessary emissions from fossil-fuel plant and interact with emissions limits. A few respondents queried whether consequences for missed SPDs were proportionate and noted that those who fail to demonstrate the first SPD in October and November would be at risk of termination, whereas providers who achieved the first SPD could subsequently be unavailable until February (the second Extended Pass Window) without risk of termination arising.

Amongst stakeholders who did not support the proposal, there were strong views that this change would negatively impact on asset operations. Respondents highlighted that planned outages, including statutory outages, are required to undertake essential maintenance for safe operation. It was perceived that tighter SPD windows could force these outages into shorter windows, at the risk of increased competition for maintenance engineers and materials, greater administrative burden and higher costs. Some respondents felt that the proposal was overly penal, particularly for events outside a Capacity Provider's control, such as delays to SPD processing, unexpected outages or network issues. A few respondents, notably from storage providers, were concerned about interactions with the Electricity System Operator's (ESO) ancillary services and felt that shorter SPD windows could force Capacity Providers to exit ancillary service contracts to meet SPD requirements. Some stakeholders also considered that the proposal could be unduly discriminatory against certain technologies, such as interconnectors due to their lack of dispatch mechanism, and for demand side response (DSR) due to the baselining methods used in the automated SPD process. In addition, a few responses raised concerns that temperature could reduce the efficiency of some gas-fired generation and create challenges in reaching required output levels to meet SPD requirements in the event of a warm October.

Many stakeholders disagreed with the proposed changes to termination, whereby a Termination Notice may be issued following failure to demonstrate an SPD within a designated SPD Pass Window or relevant Extended Pass Window. Over half of the 31 respondents who disagreed with the SPD proposal felt that this change would have unintended consequences. Stakeholders perceived that the loss of capacity through termination, particularly for failing to achieve the first SPD, would put security of supply at risk. In addition, some responses felt that an increased risk of termination may impact on investment decisions and risk reducing participation in the CM. Some respondents raised concerns with the uncertainty associated with the terminations process. Other respondents believed that bidding behaviours could be impacted, with auction participants seeking to increase bids to cover termination risk and associated fees, resulting in higher costs for consumers. A few queried how the changes would interact with secondary trading arrangements. From a delivery perspective, several responses also suggested that the proposed change would increase administrative burden, with a greater number of Termination Notices being issued and potentially more appeals to the Secretary of State.

Fewer respondents shared concerns with the proposal to suspend capacity payments. A few stakeholders queried whether Capacity Providers whose capacity payments were suspended would be sufficiently incentivised to deliver during a system stress event. These responses noted that suspension could impact delivery obligations, given interactions with the Load Following Capacity Obligation of a Capacity Committed CMU as set out in Rule 8.5.3, in a way that could be counter to security of supply objectives.

Respondents proposed a range of alternative arrangements which they considered would be preferable to the SPD framework set out in the consultation. The majority of these responses supported removing the risk of early termination, particularly for failing to demonstrate just one SPD, and proposed different SPD pass windows. The most popular suggestion was to broaden windows across the winter period, for example by having two windows that each cover three months and require a certain number of SPDs to be demonstrated in each. Many respondents who proposed broader pass windows believed that less restrictive timeframes would have fewer unintended consequences and reduce the risk of SPD requirements negatively impacting on operations. Other proposals included maintaining an early assurance window and then requiring subsequent SPDs to be demonstrated within a given time interval through winter rather than in defined months. Respondents generally supported the use of payment suspension to incentivise SPD delivery but with varying views on when suspensions should be triggered. Some suggested that suspension after two failed SPDs may be more appropriate. One response proposed that the Secretary of State should also have discretion over decisions to suspend capacity payments. One response also proposed the creation of a new penalty for failing to meet SPDs, rather than a suspension of capacity payments.

Of the respondents who proposed alternatives to the SPD proposal, the majority felt that improvements to secondary trading should be made before introducing changes to SPD arrangements. Respondents believed this would enable Capacity Providers to better manage risks of failing to meet SPDs and address concerns over potential impacts on electricity security from termination. A range of other proposals were also suggested, such as the removal of SPDs to reduce administrative burden and consideration of different SPD requirements for different technology types. Alternatively, a few stakeholders felt that instead of focussing on changes to the SPD framework, targeted solutions to address concerns around visibility of Capacity Provider availability should be explored. Suggestions to improve visibility included the introduction of additional availability declarations or the proposal requiring CMUs to be registered as Balancing Mechanism Units (BMUs)[1]. One response felt that strengthening the penalty regime would be more effective at improving delivery assurance.

Of the respondents that referenced the automation of SPDs, the majority of feedback was positive, with stakeholders reporting that automation is an improvement on manual reporting. A few responses proposed further changes to the SPD Pass Reports issued by ESC, including more frequent updates and reporting for individual SPDs, to improve data transparency and to allow for metering issues to be identified sooner. A few stakeholders felt that SPD requirements remained complex despite automation, for example for CMU Portfolios or non-standard metering arrangements. A few respondents proposed that the monitoring framework in the CM be updated to account for wider energy system activity, for example ancillary service contracts or activities in the Balancing Mechanism (BM). A few respondents felt that any changes should apply to future agreements only and requested guidance on how the proposed SPD framework would work in practise.

The proposal to clarify that where a Capacity Provider has traded part of their capacity agreement obligation, they will be required to demonstrate an SPD to the level of their CMU's Net Capacity Obligation received three responses, all of which were supportive of the proposal.

Question 2 was a call for evidence on the barriers faced by storage CMUs in meeting the performance and duration testing requirements of the CM and also sought views on potential solutions to these barriers. This question received 42 responses. Of these, 34 respondents considered that existing performance and duration testing requirements in the CM pose a challenge to batteries due to asset degradation, whereby capacity capabilities fall over time. A total of 29 of these respondents perceived the EPT framework to be a barrier to battery storage CMUs. Some felt that current EPT requirements created a greater risk of termination for batteries and may disincentivise batteries from applying for multi-year agreements. It was felt that the EPT performance level, of capacity equal to or greater than its Adjusted Connection Capacity[2] , was unduly discriminatory when compared to testing requirements for other technology classes in the CM and may disincentivise battery participation, subject to auction clearing prices. A few respondents considered that the adjustment for Technology Class Weighted Average Availability (TWCAA) added further uncertainty for testing requirements.

[1] Previously discussed in the 2021 CM consultation and government response, available at: https://www.gov.uk/government/consultations/capacity-market-2021-proposals-for-improvements

[2] The Adjusted Connection Capacity for an asset in the Storage Generating Technology Class that is duration limited is the Connection Capacity adjusted for the Technology Class Weighted Average Availability (TWCAA), as set out in Rule 13.4A.4.

A total of 22 responses raised ways in which degradation could be managed under current arrangements, to mitigate the risk of batteries failing to meet EPT requirements. The majority of stakeholders reported augmentation as a way to maintain the Adjusted Connection Capacity level. A few respondents noted that the cost for replacing cells could be recouped through cell warrantees or factored into auction bids. A few respondents felt that the costs of future augmentation were uncertain and therefore this could create an investment risk for battery developers. A few respondents also perceived that Rule 4.4.4 could be a barrier to reconfiguration. Most stakeholders who commented on how degradation could currently be managed also noted that battery assets may decide to enter a lower connection capacity at prequalification, to account for reduced capacity through a multi-year Capacity Agreement. Some respondents felt this did not represent the full value of capacity that could be delivered in the early stages of a multi-year agreement and would reduce the amount of capacity able to compete in auctions, leading to overall higher costs for consumers. Other options raised included overbuilding capacity at a multi-unit site, careful management of battery cycling over multi-year agreements or investing in battery technologies that are less susceptible to degradation. It was also noted that the risk could be managed through secondary trading of agreements if appropriate changes were made to secondary trading frameworks.

The majority of respondents felt that the CM could be changed to better incentivise battery storage CMUs and more closely align to government net zero ambitions. Most of these respondents perceived battery technologies as established, with degradation a well-known feature particularly for Li-ion battery technologies. These stakeholders argued that because degradation is a well-known feature of battery technologies, degradation should be accommodated for within the testing framework for duration-limited technologies. A few respondents also felt that wider improvements could be made to incentivise battery participation, such as considering wider activities in ESO’s Ancillary Services in testing and urgent implementation of a new Delivery Body portal to reduce administrative burden on participants, or by valuing flexibility characteristics within the CM. In contrast, a few stakeholders supported maintaining the existing testing arrangements. These respondents shared concerns around potential risks to electricity security if testing requirements were softened, as well as the risk of unintended consequences given the complex interactions with wider CM frameworks, such as derating factor methodologies. A few respondents also considered that degradation characteristics remained poorly characterised for some technologies and supported further work in this area.

A total of 23 respondents suggested changes to the EPT framework. Of these, 20 supported aligning the EPT more closely with SPD arrangements, by basing the EPT on the level of the Net Capacity Obligation (NCO) rather than the Adjusted Connection Capacity. Two respondents raised concerns with basing the EPT on the level of NCO due to perceived risks of gaming and the potential impact on costs for DSR CMUs that include storage assets. In contrast, two responses supported allowing the EPT to be reduced to a capacity level evidenced at the Substantial Completion Milestone. Six respondents believed that delivery assurance could be maintained through SPDs and supported removal of the EPT. Three respondents proposed removing the risk of termination for failing to meet EPT requirements, to minimise the risk of all of a CMU’s capacity being lost when part of it may still be able to deliver. Seven respondents supported allowing the level of the EPT requirement to be reduced through secondary trading, to enable battery CMUs to manage the risk of not being able to demonstrate their full Adjusted Connection Capacity. Other respondents also proposed allowing self-nomination of connection capacity (as explored through Section 2.3 of the consultation) to better manage testing and delivery obligations, as well as reducing the frequency of EPTs to reduce administration burden on storage CMUs. A few respondents also considered changes to Rule 4.4.4 appropriate for managing degradation, with five supporting the removal of Rule 4.4.4 in its entirety and three respondents proposing that it instead be clarified that repowering of batteries would not be in breach of Rule 4.4.4.

The majority of respondents to question 2 also suggested introducing ways for a CMU to change their capacity level over the duration of a multi-year agreement. 14 respondents suggested that applicants could submit a “degradation profile” to the Delivery Body at prequalification, that would set out the expected capacity over a multi-year agreement. Respondents proposed that obligations, capacity payments and testing requirements could be linked to this degradation profile. Three responses suggested applying a fixed “degradation factor” that would reduce the level of future EPTs. A few stakeholders also suggested allowing updates to capacity capability over multi-year agreements, for example to Connection Capacity or derating factors. It was proposed that this could be updated following annual testing of performance to enable Capacity Obligations and payments to be brought in line with proven performance. One respondent proposed that for a change that enabled a reduction in Capacity Obligation, assets could pay the difference in cost between the auction acquired clearing price of that capacity and the cost of procuring replacement capacity at the clearing price of the future auction. A few respondents instead suggested that sites should be allowed to split their connection capacity, to enable them to enter a baseline capacity for a T-4 auction and then enter the remainder of capacity into subsequent T-1 auctions. It was perceived that this would strike a balance between considering degradation but also valuing capacity that is able to deliver in the early stages of a multi-year agreement.

A few stakeholders supported urgent changes being made to the EPT framework. Of the five respondents that shared views on how such changes could be implemented, the majority supported changes being applied retrospectively to existing capacity agreements. Respondents felt that this would maintain a level playing field between storage projects and avoid penalising early adopters of innovative technologies. One respondent believed changes should only apply to agreements awarded after any changes are put in place, as they felt that degradation issues were likely already factored into auction bids. A few respondents also queried interactions with Ofgem’s change proposal process, facilitated through the Capacity Market Advisory Group (CMAG), and whether changes to the EPT may be raised through this route.

Policy response

The government welcomes the detailed feedback on the proposed changes to the SPD framework. In light of the concerns raised in relation to the impacts on security of supply and market signals, the government will not be implementing the proposal as consulted on at this stage. The government will instead progress this policy proposals as part of phase 2, with a view to implement from 2024 at the earliest, subject to further analysis and development. This will include a consideration of what further steps might be appropriate to strengthen delivery assurance. Interactions between changes to the testing and performance regime and secondary trading arrangements will be explored and government will engage with delivery partners, including Ofgem, in this process.

The government welcomes the evidence provided in responses regarding the barriers faced by storage CMUs in meeting the performance and duration testing requirements of the CM and views on potential solutions to these barriers. Several respondents requested urgent changes be made to the EPT arrangements, and the government notes queries raised around interactions with CMAG change proposals. Given the range of solutions proposed by respondents and the complexity of interactions between testing arrangements and derating factors, the government intends to review the solutions proposed against wider system arrangements, to better understand the potential impacts.

Connection Capacity

Section 2.3 consulted on reforming the way connection capacity is assessed in the CM to ensure a higher degree of accuracy in assessing the security of supply contributions of capacity providers. Options for selecting the amount of connection capacity to enter into the CM will be limited to either a CMU's Transmission Entry Capacity (TEC), Maximum Export Capacity (MEC), or Average Output (on the basis of historic metering data). The proposed approach would remove the option to base connection capacity on Connection Entry Capacity (CEC) for Transmission CMUs, as well as streamline the options available for Distribution CMUs. This change aims to ensure that a CMU's connection capacity accurately reflects the capacity it can credibly export to the transmission or distribution network, and to simplify the process for determining a CMU's connection capacity by clarifying and harmonising the options for different CMUs under the Rules.

Summary of responses

Question 3 sought feedback on the government proposal to amend the Rules to enable Capacity Providers to determine a CMU's connection capacity on the basis of TEC, MEC or Average Output. Stakeholders were also asked to comment on whether there would be unintended consequences of this approach. This question elicited 37 responses. Of these, 14 respondents provided clear support, while a further four respondents indicated support but also noted areas for further consideration. 15 respondents did not support the proposal. A further five respondents did not declare a position, but shared feedback on additional considerations for the proposal.

Supportive respondents felt the proposed approach to streamline the options available for determining a CMU's connection capacity and simplify the framework was sensible. Some respondents felt that the proposed change would ensure that a CMU's capacity more accurately reflects their ability to deliver during times of system stress and noted support for the government's decision to not progress with the creation of a connection capacity test at this time. Responses which offered further justification of their support for this change considered that the options proposed fell broadly in line with existing connection capacity arrangements and would work for the majority of CMUs. A number of further considerations were raised in supportive responses, including a request for greater clarity on how the new framework would apply to different CMUs, such as multi-unit sites and requests to retain the option to provide an "estimate in good faith" as currently facilitated by Rule 3.5.2.

Respondents who opposed the changes to limit the options to TEC, MEC or Average Output raised concerns around what they saw as potential unintended consequences of the proposal. Some stakeholders expressed the view that removing Connection Entry Capacity as an option could increase the demand for commercial agreements for network capacity such as TEC, with two respondents of the view that this would be particularly inefficient for assets that also consumed energy on site. Of these respondents, a few shared concerns with existing delays in processing grid connection agreements and felt that this proposal could exacerbate issues with competition for connection agreements. A few respondents felt that the risk of assets overstating their connection capacity was already managed appropriately, through uplifts in auction targets.

Question three also noted that government is minded to require Capacity Providers whose CMUs are part of multi-unit sites to cap the sum of the connection capacity of the relevant units at the site level of TEC or MEC. This is to avoid situations in which the connection capacity of individual units on a multi-unit site may be overstated in relation to the total site TEC or MEC. Some respondents raised concerns about what they saw as potential impacts on incentives for co-located assets of this proposal. These respondents felt that sites which had co-located renewable generation and storage assets may have a shared grid connection value lower than the total of the nameplate capacities at that site, and that limiting the connection capacity to site level TEC or MEC could impact on incentives to build out co-located assets. A few stakeholders felt that capping the sum of connection capacity, rather than capping the sum of de-rated capacity, risked increased costs for consumers as they considered it would require additional capacity to be procured. A few of these respondents believed that this could be particularly inefficient for sites with highly derated technology types, such as renewable generation. The majority of respondents who disagreed with this proposal felt it would be more appropriate for Capacity Providers with CMUs as part of a multi-unit site to cap the sum of the de-rated capacities at the site level of TEC or MEC. A few of these respondents caveated that this should be allowed, provided that Capacity Providers can evidence that the site level of TEC or MEC is not exceeded, and one respondent noted that this approach would remain consistent with wider agreement requirements for testing and delivery on obligations. A few stakeholders also requested clarity from government on the role of co-located assets in the CM and questioned whether the creation of a new technology class with specific de-rating factors would be a more effective approach.

Question 4 sought views on whether Capacity Providers would prefer to be able to self-nominate their connection capacity, provided the nominated figure is not higher than TEC, MEC or Average Output. This elicited 41 responses, with strong support for self-nomination of connection capacity. The majority of respondents were supportive, with 33 stating a preference for self-nomination and a further three respondents indicated caveated support. One respondent did not agree with self-nomination and three respondents did not state an overall position but raised additional considerations.

Of the stakeholders who stated support for self-nomination of their connection capacity, the majority agreed with self-nomination up to TEC, MEC or Average Output. Others supportive of this principle felt that self-nomination would be preferable if aligned with current connection capacity arrangements, with the ability to self-nominate up to Connection Entry Capacity (CEC) as well. Supportive respondents considered self-nomination provided a route for Capacity Providers to manage risks to delivery against obligations, particularly for agreements awarded at T-4 stage, which numerous respondents believed Capacity Providers were best placed to assess. In particular, a few stakeholders felt that self-nomination of connection capacity could allow Capacity Providers to better manage some technology-specific risks, such as the impact of battery degradation on the ability to meet Extended Performance Testing requirements (as explored in section 2.2.3 of the Consultation) or refurbishment plans. One respondent felt that the principle of allowing Capacity Providers greater control over their agreement level, given the view that the provider will be the most informed about their delivery capabilities, should be extended more broadly across the CM. A few stakeholders also highlighted that there are existing requirements within Capacity Market agreements that provide protections against concerns over impact on delivery assurance, such as testing requirements and penalties for non-delivery.

Of the other responses to question 4, one stakeholder raised gaming concerns. Three stakeholders also asked for government to consider what the remainder of a Capacity Provider's capacity should be used for and queried whether this additional capacity could be used in Secondary trading or in future T-1 auctions if this change were to be implemented. One respondent considered that greater flexibility in the timescales for self-nomination would enable Capacity Providers to optimise against delivery risks based on updated views of auction participation.

Policy response

In line with the majority view of respondents, the government intends to proceed with changes to connection capacity in line with consultation proposals to streamline arrangements and ensure better value for consumers by reducing the risk of CMUs overstating their connection capacity. For example, CEC can currently be used to determine the connection capacity and a CMU's TEC may be lower than its CEC. Over the past six years, the Delivery Body has increased the recommended T-1 target capacity by an average of 0.9GW to account for the difference between the TEC and the nominated connection capacity awarded agreements in the earlier T-4 auction[3].

The government recognises the concerns raised in consultation responses around the increased demand for TEC and MEC, and impact on co-located assets which may play an important role in reaching a net zero electricity system. However, the government notes that the purpose of derating factors is to act as a fleet-level correction to account

[3] https://www.emrdeliverybody.com/CM/Capacity.aspx

for the expected availability of different technology types, and believes that connection capacity should reflect the export capacity of an asset. The government therefore intends to implement the proposal as consulted but will continue to consider the impacts on incentivising co-location.

To implement this change, the government intends to make changes to the Rules as necessary to limit the options available for applicants to determine their connection capacity to TEC, MEC or Average Output. In light of feedback, the option for Prospective CMUs who are distribution connected to make an estimate in good faith of connection capacity will be retained, to accommodate CMUs who may not yet have the relevant information to determine TEC, MEC or Average Output. For units that do not have TEC or MEC specified at the site level, and are not able to determine an individual Average Output value, options will be retained for units to determine an appropriate connection capacity for the individual unit, as a portion of the site TEC or MEC, provided that the sum of the connection capacities at that site does not exceed the total site TEC or MEC. The government will work with delivery partners to ensure timely updated guidance for CM participants.

The government welcomes the views shared on the option for applicants to self-nominate connection capacity, provided the value does not exceed TEC, MEC or Average Output. While feedback received was broadly supportive of the proposal, the government intends to explore this policy proposal further as part of phase 2, including undertaking further analysis and development in order to better understand interactions with wider arrangements.

Mothballed Plant

Question 5 consulted on proposals to remove barriers to mothballed plant from prequalifying in the CM by amending the rules relating to providing evidence of Previous Settlement Performance for existing CMUs. In 2022, a temporary rule change was put in place following the government’s consultation on improving liquidity in the CM, to address barriers to mothballed plant.[4] Question five sought to explore appropriate permanent changes to enable mothballed plant to apply to prequalify for Capacity Market auctions. The proposal would place a new requirement for existing generating CMUs, which are not able to demonstrate 24 months of Previous Settlement Performance, to provide credit cover until they have demonstrated their first SPD.

Summary of responses

Of the 35 responses to question 5, 15 agreed with the proposal and a further 13 generally agreed with the proposal but presented some caveats. The main theme of supportive respondents was that the delivery assurance put forward in the proposal was enough to enable

[4] Government response to consultation available at: https://www.gov.uk/government/consultations/capacity-market-rules-amendments-to-improve-auction-liquidity/outcome/capacity-market-rules-amendments-to-improve-auction-liquidity-government-response

mothballed plants to be permitted to re-enter the CM. Five respondents also commented that this is a necessary route and some respondents noted the requirement to ensure security of supply.

Of the 13 respondents who agreed with the proposal but presented some caveats, there were mixed views on whether alternative or additional assurance would be necessary for mothballed plants to re-enter the CM. Two respondents said that once the plants were able to provide assurance, they should have their credit cover released, even if this is before the start of the relevant delivery year. However a further five respondents felt that more assurance should be required, and two of those respondents felt that mothballed plants should be treated like new build CMUs, whilst others also put views forward that they should be kept distinct from new build CMUs. One respondent also suggested a specific test that mothballed plants would have to comply with to enable them to participate.

Five responses did not agree with the proposal, with views that enabling mothballed plants to participate in the CM would go against the principle of the mechanisms to encourage new build capacity.

Policy response

This proposal is closely linked to the SPD proposal. As set out above, this will continue to be progressed as part of phase 2, with a view to implement from 2024 at the earliest, subject to further analysis and development. Therefore, the mothballed plant proposal will also continue to be developed in parallel, to ensure appropriate mechanisms are in place to provide delivery assurance.

In the interim, government will seek to extend the existing temporary measure in relation to mothballed plant. This was put in place for the Prequalification Window 2022. This allowed existing generating CMUs that could not meet the requirement of Rule 3.6.1 to provide performance data that was older than 24 months prior to the end of the Prequalification Window. The extension of this measure will apply to the 2023 Prequalification Window only and the associated 2024 auctions. These plants will still have to demonstrate satisfactory performance during the delivery year, as per all other capacity partaking in the CM. This temporary change has not been applied to secondary trading entrants.

An assessment of impacts on the participation of mothballed plants on a temporary basis was included in the ‘Capacity Market: rules amendments to improve auction liquidity consultation in July 2022’.[5] To recap, the measure will increase the pool of capacity eligible to apply to prequalify for the Capacity Market, and allowing a greater number of CMUs within the CM may increase liquidity, putting downward pressure on clearing prices and the overall costs of the CM.

[5] Further information available at: https://www.gov.uk/government/consultations/capacity-market-rules-amendments-to-improve-auction-liquidity

At the time of the original assessment for the 2022 change, the government highlighted the risk that this rule change may lead to CMUs winning agreements that they cannot deliver on. While other measures exist to minimise this risk (such as penalties and termination fees), the measure was introduced on a temporary basis and the government intends to maintain this position for the change for the 2023 Prequalification Window.

Penalty Regime

Questions 6 and 7 consulted on strengthening the non-delivery penalty regime and amending the timeline for issuing non-delivery penalties. Changing the figure used in calculating the penalty rate from 1/24 to 1/4 aims to send a stronger signal to deter non-delivery of capacity in a System Stress Event (SSE), given that Capacity Providers would be exposed to higher penalties. Changes to the non-delivery penalty regime have been considered as an area of priority reform since the CM Five-year Review in 2019, in which government and stakeholders agreed that the current regime may not act as a sufficiently strong deterrent against non-delivery in times of system stress. The consultation also proposed to amend timelines so ESC would have 35 working days following the month in which a SSE occurs to invoice Capacity Providers who are liable for penalties, instead of 25 working days as is currently the case. Amending the timeline for issuing non-delivery penalties ensures that the Settlement Body for the CM (ESC) have sufficient time to calculate and issue accurate penalties as the present timeline may result in errors regarding the accuracy of calculating Relevant Balancing Services.

Summary of responses

Question 6 consulted on our proposal to strengthen penalties for non-delivery and sought views on potential unintended consequences of increasing the penalty rate as follows:

Penalty rate (expressed in £/MWh) = clearing price (£/MW) x 1/24

to:

Penalty rate (expressed in £/MWh) = clearing price (£/MW) x 1/4

Question 6 received a total of 47 responses, five of which agreed with the proposal and 12 that indicated caveated support. A total of 23 respondents did not support the proposal and a further seven did not state a position but shared additional considerations.

Of the 17 total respondents that indicated support, or caveated support, for the proposed increase to the penalty rate, the overarching view was a perception that current penalties for non-delivery may not sufficiently incentivise delivery against Capacity Obligations, and so supported strengthening the penalty rate. One respondent supported the view that the change would be to the overall benefit of consumers. It was noted by a few respondents that they were of the view that penalties in the CM felt low when compared to incentives in other electricity frameworks, such as imbalance costs in the BM. Of the respondents that indicated caveated agreement with the proposal, a number of wider considerations were suggested to support implementation, such as reviewing the level of the penalty cap, secondary trading arrangements and signals of system stress in the CM. One respondent also noted support, provided SPD arrangements remained unchanged.

The majority of respondents shared concerns about potential unintended consequences of the proposed change, including those who gave caveated support or did not state a clear position of support. Of the 23 respondents who did not support the proposed change to the penalty rate, 13 supported the principle behind a strengthened penalty regime, but did not believe the proposed change was appropriate and felt that it would have a number of unintended consequences. Six stakeholders felt that the current rate was sufficient to incentivise delivery. In addition, some respondents considered that, given there have been no SSEs since the implementation of the CM, there is insufficient evidence that a change to the penalty framework is required to better incentivise delivery and that the impact of the proposed change to penalty rate is therefore uncertain. A few respondents requested further rationale to justify the change in the penalty rate chosen, noting that this was the highest rate considered through the 2021 Call for Evidence, and supported a more detailed assessment of impacts before implementing the proposal.

Many of the stakeholders who did not support the proposal felt the chosen penalty rate increase to 1/4 was too high, and a few felt that this was particularly the case when considered alongside the proposed changes to SPDs as discussed in section 2.2 of the consultation. Overall these respondents felt that the increase in penalty rate was significant and raised concerns around a potential imbalance between penalty rate and the monthly penalty caps that would remain unchanged. Stakeholders noted their view that the proposed increased rate would mean that CMUs that did not deliver during an SSE would reach their monthly penalty cap within 40 minutes under the proposed rate. These respondents felt that this risked removing incentives to deliver once the penalty cap is reached, which could worsen security of supply impacts. In stakeholders' opinions, the main unintended consequence was the impact on CM participation and investment incentives. The majority of non-supportive respondents felt that increased penalty rates raised the risk of higher costs for Capacity Providers, and may reduce appetite for CM participation. Some respondents felt that this could have different impacts for different types of technologies. For example, some respondents voiced the opinion that the higher penalty rate might tip the balance of risk-reward too far for technologies that cannot self-dispatch or for first-of-a-kind technologies and those perceived as key to the net zero transition. A few respondents felt it might create potential distortive impacts for participants for whom CM revenues played a larger role in investment cases. Responses also felt that the risk of higher penalties may increase auction costs, and therefore costs for consumers. These respondents felt that costs for consumers may increase due to reduced auction competition, lower participation in the CM, and higher exit bids from participants who might seek to cover the increased penalty risks.

There was broad agreement across respondents (both supportive and opposing) that changes to penalty rates should only apply to agreements awarded after a change is implemented. Some of these respondents felt that the risk of non-delivery penalties was a key factor in business planning and therefore would be factored into exit bids.

A range of alternatives and wider considerations were raised by stakeholders. Some stakeholders felt that improvements to Secondary trading were required before changing the penalty regime to enable Capacity Providers to better manage risks of non-delivery. A few stakeholders felt that changes to testing arrangements, such as SPDs, would be more effective at providing greater assurance of delivery than changes to non-delivery penalties. A few respondents supported a wider review of the penalty framework, including considerations of a lower penalty rate than the one proposed in the consultation. Feedback on whether the penalty cap should be changed was split, with half supporting the maintenance of the monthly penalty cap at 100% to avoid impacts to CM participation and half supporting a wider review of the balance between the penalty rate and cap to maintain delivery incentives throughout an SSE. Two responses felt that changes to the penalty rate should consider other factors, such as delivery incentives in the Balancing Mechanism, or instances of repeated non-delivery that may warrant stronger penalties. A few stakeholders asked for delivery signals in the CM to be reviewed. These respondents generally noted that improvements to SSE signals or the Capacity Market Notice (CMN) would in their view enable assets to optimise their dispatch to meet their Capacity Obligations, as well as better understand their risk of non-delivery and manage risks. In particular, a few respondents felt a review of the 4-hour ahead CMN trigger point and level would be valuable, to assess whether the signal remained appropriate to the technology mix of CM participants. A few respondents also asked for a review and clarification of “force majeure” clauses in the CM and one respondent supported a mock SSE.

Question 7 sought views on whether stakeholders agreed with amending timelines for calculating non-delivery penalties, to enable ESC to have sufficient time to accurately calculate penalties for Capacity Providers. Question seven received 32 responses, of which 23 were supportive, one did not support, and eight which did not state a position but raised other considerations. Of the supportive respondents, the majority agreed that accurate penalty calculations were important. A few respondents suggested that changes should allow for invoices to be issued before 35 working days if they are ready before this time and one respondent supported a more holistic review of the penalty framework. Of the eight respondents that raised other considerations, some felt that improvements to delivery partner systems would enable greater efficiency, and a few respondents asked for clarification on the scope of timeline extensions and queried whether other penalty requirements would also be changed. The one response that did not support the proposal felt that penalties processes should be made more efficient instead of changing timelines.

Policy response

In light of stakeholder concerns raised in relation to the interaction between the penalty rate and penalty cap, and the potential unintended consequences for security of supply, the government does not intend to make changes ahead of the 2023 CM prequalification window. The government welcomes the detailed feedback shared in responses and recognises the concerns raised with the proposal. The government will continue to consider appropriate changes to the penalty arrangements to ensure that the right balance is struck between incentivising delivery and limiting potential unintended consequences. The government intends to explore this policy proposal further as part of phase 2, including undertaking further analysis and development.

In line with the majority of responses to question 7, the government intends to implement the proposal to amend the timelines for ESC to calculate non-delivery penalties, parliamentary time allowing. The government intends to make a change to Regulation 41(2) to amend the current 21 working day deadline to allow 35 working days, as described in section 2.5.3 of the 2023 Consultation. Following feedback on wider system improvements and amendments to other penalty requirements, the government will continue to explore if complementary changes are required and will consult stakeholders if appropriate changes are identified.

Aligning the Capacity Market with net zero

This chapter summarises Questions 8 to 28 of the consultation, which considered a range of issues and options related to aligning to net zero and removing participation barriers for low-carbon technologies within the Capacity Market.

Aligning Capacity Market Agreements with decarbonisation commitments

Questions 8 to 11 consulted on our proposal to introduce new emission limits, from 1 October 2034, for new and Refurbishing CMUs which are awarded multi-year agreements after the relevant amendments implementing the revised emission limits come into force. The new emission limits would bring the current emissions intensity limit of 550gCO2/KWh down to 100gCO2/KWh from 1 October 2034.

The proposal also set out government intent to expand access to the existing yearly emission limit which, set at 350gCO2/kW, currently only applies to existing plants if they do not meet the emissions intensity limit. The proposal sought to expand it to new and refurbishing plants post 1 October 2034, thereby allowing unabated gas to continue operating peaking profiles to safeguard energy security.

The purpose of the two limits together was to move the CM towards closer alignment with our goal of a fully decarbonised power system by 2035, subject to security of supply, by incentivising unabated gas plants to either abate by 2035 or operate a limited peaking profile beyond 2035. Existing capacity was not to be affected under these proposals, except when taking a long term CM agreement to refurbish, as the proposals were primarily aimed at ensuring new build non-peaking fossil fuel generation is not locked in past 2034 through long term CM agreements.

Summary of responses

Question 8 asked respondents whether they agreed with our proposal to introduce lower emissions limits for new and Refurbishing CMUs from 2035. It elicited 53 responses, with 33 respondents supporting our proposal, including 20 which provided qualified support. 15 respondents disagreed and a further five were either unclear or neutral.

The most common views exhibited in the fully supportive responses included the notion that our emissions limit proposal was important for incentivising decarbonisation, sending the necessary signals to investors and providing the necessary clarity on our intent to align with net zero. A few respondents also urged for alignment on emissions limit rules across all available and proposed support mechanisms, such as the Dispatchable Power Agreements (DPA) for power-Carbon Capture Use and Storage (CCUS), and the proposed business model for power-bioenergy with carbon capture and storage (power-BECCS).

A few respondents raised concerns over the replacement of unabated capacity, with respondents urging for more clarity on government plans to replace baseload and mid-merit unabated capacity, and analysis on the impact our proposals would have on security of supply. One respondent also asked for greater clarity on how biomass and power-BECCS would be treated under the new emission limits.

Of the 20 respondents who provided qualified support, almost half agreed with the direction of travel, but argued our proposals were not ambitious enough. Views included the opinion that there was a need to introduce emissions limits sooner, or to introduce them sooner but with a sliding scale of emissions limit reduction, to apply emissions limits to existing capacity as well, and specific disagreement with the yearly emissions limit proposal. The latter point included respondent views that unabated flexible gas was unduly favoured and was incompatible with net zero. This came alongside suggestions of either tightening yearly emissions limits, or reviewing them regularly as low carbon technologies mature.

A few respondents agreed with the general premise but felt that the CM was either not best placed, or not sufficient alone, to drive the required changes for net zero. This included views that the government should focus on investment in low carbon projects and infrastructure, use other mechanisms for emissions reduction, or focus change efforts via REMA.

Of the 15 respondents who disagreed with our emissions limit proposal, almost half felt our proposals did not go far enough. Some argued that existing mechanisms were better placed to achieve emission reductions, such as the emissions trading scheme (ETS) or via environmental regulations, whilst the CM should focus on capacity. A few respondents also expressed the view that there was currently a lack of viable technologies to replace unabated capacity.

A few respondents raised concerns about the impact of the proposal on security of supply and value for money. The perceived risks raised by those respondents included plants taking shorter agreements or leaving the CM entirely, the CM having to buy more capacity than required, and small scale unabated peaking plant allowed for by the yearly emissions limit being insufficient during extended periods of wind drought. Other objections related to the perception of these respondents that the proposal was ‘picking winners’ and would disincentivize low hydrogen blends which could provide a stable source of offtake for the nascent low carbon hydrogen production industry.

Some respondents who disagreed with the proposal posited preferred alternative solutions, including the prevention of high carbon plant from accessing multi-year agreements, or focusing on incentives such as ‘price multipliers’ for low carbon technologies.

A few respondents expressed specific misgivings about elements of the proposal, which they felt would not go far enough to decarbonise the energy system. This included a view that power-CCUS and hydrogen-to-power maintain a link to fossil fuels and lock in upstream emissions, and that if the government did proceed with the proposal it should include a review clause to react appropriately should new low carbon technologies be developed. One respondent also raised concern related to the timescales required to obtain a hydrogen connection.

A further five respondents exhibited an overall neutral or unclear stance on the proposal, however the views they shared have already been covered.

Question 9 asked whether stakeholders agreed with our proposed changes to the emissions limit regime to facilitate the lower emissions limit proposal. The question elicited 43 responses with 25 respondents supporting our proposed changes to the emissions regime, including six who provided qualified support. 11 respondents disagreed and a further seven were either unclear or neutral.

Many of the responses to question 9 contained commentary on the emission limits proposal itself and repeated the views expressed in response to question 8.

Of the 25 respondents who expressed full or qualified support of our proposed changes to the emission limits regime, some agreed that the requirement for Fossil Fuel Emissions Declarations (FFEDs) to be submitted annually made sense. Others wanted greater clarity on how abated technologies unable to meet their limits due to cross chain issues would be treated, as well as consideration of future carbon intensity if the gas grid itself decarbonised via the introduction of hydrogen and biomethane blends.

Of the respondents who disagreed, many raised the same issues as for question eight, including views relating to the proposal's perceived misalignment with net zero, and that the proposal would not send the required investment signals for low carbon technologies.

Views specifically relating to the emissions limit regime included the questioning of the rationale behind declaring emissions four years prior to delivery (in the case of the T-4 auctions), and the suggestion that other regimes, such as Emissions Permitting Regulations (EPR), could capture the emissions information required by the CM. A few respondents took issue with the annual FFEDs based on their views that they caused additional cost and increased the administrative burden, particularly for capacity providers with multiple small peaking generators.

Of the respondents whose overall position on the proposals was neutral or unclear, a number advised more thinking, or requested further guidance, on how running hours would work in context of a system stress event. One respondent raised concern about the uncertainties of the cost and development of CCUS and hydrogen technologies and advised DESNZ delay implementation until early 2024.

Question 10 had 27 responses, and asked whether there were any further required changes to the emissions limit regime which the government had not identified. As with question 9, respondents often posited views on the proposed emission limits, as opposed to the required changes to the emission limits regime necessary to implement them. Of the respondents who did specifically share views on required changes to the emissions limits regime which the government did not identify, a number alluded to the importance of ensuring IEVs have sufficient capacity to conduct checks. One respondent felt there was a need for a flexible approach to unabated peaking plants in case of a system stress event.

Some views which did not directly relate to changes to the emissions limit regime, but weren't raised for previous questions, were the suggestions to alter the derating factors for solar and wind, and a refocus on demand reductions.

Question 11 had 31 responses and asked whether respondents had any views or evidence on the impact that the emissions limit proposal might have on investment in transitional pathways, such as hydrogen blending or CCUS retrofit. Almost a third of respondents to this question shared views on why they thought that the CM alone was not sufficient to drive the necessary investment in transitional technologies. Issues raised included the build out of transport and storage (T&S) networks required for both CCUS and hydrogen, power grid connection delays, on-site space limitations for abatement of existing assets, and the uncertain role of hydrogen in the future energy system.

A few respondents noted that a clear stance on emission limits can help move the market to new technologies, but a few others felt that more investment incentives are needed alongside this.

Two respondents raised the concern that the emission limits might stymie the development of low carbon hydrogen production through its preclusion of low hydrogen blends, which would not meet the proposed new emission limits. Stakeholders felt that a gradual increase in hydrogen content in blends might be the most effective way to stimulate hydrogen production and enable the transition to full, or almost full, hydrogen fired generation.

Other concerns raised included the view that if the CM was to support transitional pathways based on unproven technologies which might not come to fruition, it would distort the market for other participants as it could lead to a perpetuation of fossil-fuel plant and undermine support for existing low carbon options. Finally, one stakeholder suggested that by not enforcing emissions reductions soon enough, government could be extending the risk of generators making further investment in unabated technologies instead of low carbon ones.

Policy response

In line with the broad support for greater alignment of the CM with net zero, the government remains committed to introducing an emissions limit reduction into the CM to help drive the transition to a net zero power system by 2035, subject to security of supply.

The government intends to progress these policy proposals as part of phase 2, with a view to implement from 2024 at the earliest, subject to further analysis and development. This is key to ensuring government can progress its ambitions for a clean energy system in a way which takes account of increased geopolitical uncertainty, and the resultant impact on energy security. The government appreciates the time stakeholders have taken to engage with us on the matter.

While the government recognises that progressing this policy as part of phase 2 harbours the risk of a new tranche of long-term agreements being awarded to unabated capacity in the CM auctions in 2024, the impact of this capacity on our 2035 ambition must be qualified by our ongoing commitment to enable clear and effective decarbonisation pathways for existing capacity. The government remains committed to achieving a fully decarbonised power system by 2035, subject to security of supply, and the actions that will set us on a course for this have been set out in the Energy White Paper, Net Zero Strategy, British Energy Security Strategy and Powering Up Britain - Energy Security Plan.

Decarbonisation of existing Capacity Market Units

Questions 12 to 18 called for evidence on barriers to the decarbonisation of existing capacity market units. High carbon Capacity Market Units (CMUs) with long-term agreements may not be able to access new investment support schemes or rebid into the CM to decarbonise their CMU if they're unable to leave their agreement early.

Government committed in the Powering Up Britain – Energy Security Plan to develop enablers for clear decarbonisation pathways for unabated gas generation alongside facilitating the deployment of low-carbon flexibility technologies and services. These pathways include the Decarbonisation Readiness requirements proposals recently consulted on for new build and substantially refurbishing combustion power plants to be built in such a way that they can easily convert to either 100% hydrogen-firing, or retrofit carbon capture equipment within the plant's lifetime. The CM 'managed exits' pathway proposal sought views on enabling CMU long term agreement holders to leave their agreements early in order to decarbonise, subject to certain conditions being met.

Any CMUs leaving the CM for alternative support mechanisms may reduce the CM's capacity pool permanently (e.g. by securing a DPA), or temporarily (e.g. going offline to convert to low carbon operation) which would need to be replaced to ensure ongoing security of supply. The government is seeking evidence on Capacity Providers' plans to decarbonize their CMUs, particularly if it involves exiting the CM, as well as on options for how the CM might facilitate their decarbonisation whilst safeguarding security of supply.

Summary of responses

Question 12 had 20 responses. It asked respondents which had an unabated gas CMU what their plans were for this capacity as the power sector decarbonised, and whether they intended to decarbonise their CMU once viable pathways, such as DPAs, became available. Of the 20 responses to this question, 13 respondents stated they had plans for decarbonisation, two said they did not, whilst a further five offered an unclear stance.

Out of the 13 respondents with unabated gas plant(s) in the CM which were looking to decarbonise, over half stated they were either ready to decarbonise as soon as a credible option was available and/or were actively looking for decarbonisation pathways such as CCUS or hydrogen conversion. Three respondents specifically stated their intention to convert to hydrogen/a hydrogen blend, however they noted dependencies including support from various government funds and extensive hydrogen T&S build out. One respondent said they intended to reduce their running hours, and another stated their intent to retrofit their plant with CCUS. A further two respondents raised potential blockers to decarbonisation, such as the 3-year agreement to refurbish in their view not being enough of an incentive to decarbonise, and the interaction between the CM and the end of a DPA contract. For the latter risk, the respondent felt it was important that the two do not undermine each other through timing misalignment (i.e. if a DPA contract ends too late for a generator to switch to the CM for the active delivery year).

The one respondent with a CMU which they did not intend to decarbonise, elaborated that the reciprocating engines they operate would have reached their end of life by 2035.

The five respondents which did not state their intent one way or the other, referenced the difficulty of commenting due to a lack of viable pathways and not having established how long outages would be (and therefore whether they could decarbonise within an existing CM agreement or not). Two of the respondents referenced the need for flexibility when considering specific technologies and the proposed requirement that they abate by 2035. This included one respondent who stated the capacity for bioenergy to abate by 2035 is dependent on the pace of the Greenhouse Gas Removal (GGR) business model development, but that lack of abatement should not be a barrier to participation in the CM due to the biogenic nature of the capacity. Another advised that small, distributed gas generators are particularly reliant on there being an active T&S network for hydrogen conversion, due to the challenges of having multiple small, distributed hydrogen storages sites.

Question 13 sought views from the perspectives of Capacity Providers on what additional barriers there were to decarbonisation and whether it would be necessary to terminate their CM agreement to do so. It had 23 responses.

The most commonly cited barriers, raised by nine respondents, related to the development of CCUS and hydrogen transport and storage infrastructure and supporting regulatory frameworks. Three respondents also mentioned specific dependencies on the hydrogen trials and the CCUS cluster sequencing process. One respondent identified the perceived insufficient empowerment of economic regulators to support anticipatory investment in future networks as another barrier.

The second most commonly raised barrier was rule 4.4.4, with six respondents urging for it to be revised. A number of other issues were raised relating to the design and function of the CM, including the five respondents which highlighted what they perceived as a lack of clarity on how to decarbonise within an existing CM agreement, how to transfer to a DPA, and how blended hydrogen would impact derating factors. Other perceived barriers included that the £75/kw price cap was too low for delivering decarbonisation, the need to improve secondary trading rules and CM portal, the T-4 auction timing not giving the full four years before the delivery year and thereby limiting available time for planned outages, and the definition of the maximum obligation period, which currently precludes existing capacity from bidding for long term (3+ years) refurbishment agreements. One respondent also felt that the CM rules need to include consideration of the potential 10-15% decrease in capacity of a refurbished CMU due to the parasitic load of carbon capture equipment.

Two respondents felt that the CM auction structure itself was a barrier, expressing the view that a split auction, for example with a separate auction for first of a kind (FOAK) technology, would be optimal to bring forward new low carbon technologies.

A number of respondents identified barriers relating to the deployment and installation of decarbonising and alternative fuel technology. This included a lack of clarity on which technologies to install and the perceived lack of viable options. One respondent specifically mentioned the lack of a technology which can burn both 100% natural gas and high hydrogen blends. Two respondents each mentioned site space constraints for installing new equipment, and the cost of hydrogen. Other barriers raised by respondents included the issue of supply chain bottlenecks, the perceived inefficiency of the planning and consenting process, the lack of incentives for low hydrogen blends to initiate the transition, and the need to address the high NOx emissions from high hydrogen blends.

Of the respondents who directly addressed whether they would need to terminate their CM agreement to decarbonise, three stated they would, or would likely need to, advising this would be to avoid non-delivery penalties, and that termination would be particularly necessary for large volume units which would take longer to retrofit. Three stated they would not, or would be unlikely to need to, with reasons given being the possibility of interchangeably using a low hydrogen blend or 100% fossil gas, and the ability to opt out of a T-4 auction to schedule works and then to apply to prequalify for a T-1 auction.

Question 14 asked Capacity Providers how long it would take to retrofit their plant(s) to either CCUS or hydrogen and when it would be feasible for their plant(s) to come offline to do so. It had 17 responses.

On the topic of how long it would take to retrofit their plant(s) four respondents suggested ‘several years’, including one which specifically referred to a retrofit for full or high blend hydrogen firing. One respondent suggested a minimum of five years depending on specifics, and another specified that procurement and engineering would take 12 months.

Three respondents referred to CCUS conversions in their answer, with two of the responses agreeing on approximately three years for construction, with one adding the need for two years for studies and tendering beforehand. The third respondent only stated that CCUS conversion would take longer than hydrogen.

Four respondents suggested it was too early to provide useful estimates as feasibility studies were either still in progress or had yet to begin, and one respondent advised the time necessary to retrofit was highly site dependent.

Eight respondents also provided estimates of how long an outage would be as part of the retrofitting process. There was a range of answers spanning from one to eight months. Responses referencing low hydrogen blend retrofits predicted the shortest outage times of around one to three months, whilst those referring to higher hydrogen blends and CCUS retrofits predicted three to eight months.

Question 15 sought feedback on our suggestions for how CMUs could decarbonise, and asked respondents whether they had their own suggestions. It had 29 responses.

Seven respondents referred to Capacity Obligation pauses, out of which five advised against them. Reasons cited included the perception of risk of auction distortion due to participants waiting for higher prices to lock in prior to entering, the perception that this favoured gas CMUs, the existing T-4 and T-1 auction interaction being sufficient to accommodate decarbonisation, the preference for payment termination or the CfD/DPA route for decarbonisation, and that the cost of compliance with legislation should be borne by the asset directly. One respondent supported obligation breaks, and another proposed a credit-cover requirement for assets at risk of requiring significant re-investment in refurbishment, to minimise the risk of the capacity provider failing to deliver on their obligations.

Other points raised included the desire for a decarbonisation standard to be attached to obligation pauses, and that a decarbonisation route would not be necessary for generators which are not locked into contracts beyond 2035. A further issue raised was that as large CMUs may decarbonise in phases, rules around agreement pauses and terminations should consider individual generating units.

Four respondents specified that the definition of decarbonisation needs to be broad, technology neutral, and be consistent across all relevant mechanisms and frameworks. Two responses covered provisions for transfers, with comments provided such as the need for the provisions to be wide enough to cover the transfer of capacity to any other renewable support scheme to ensure better responsiveness to electricity system requirements.

Technology related risks and use cases were raised by seven respondents. Respondents felt that hydrogen blending offers minimal emissions reduction and shared the view that CCUS technology was still nascent and needed testing and scaling. Two respondents questioned whether it was advisable to rely on T&S infrastructure for hydrogen and CCUS to develop in time, and underlined the perceived risk of offering carbon intensive technology 15-year contracts in the hope they would decarbonise within the required timescales. One respondent raised the view that there were limited options to decarbonise reciprocating engines.

Six respondents specifically argued for greater focus on enabling the proliferation of existing DSR technologies by improving incentives, removing capex limits, and rewarding the capability for flexible ramping rather than just focusing on derating factors. Three respondents contended that providing exit routes for decarbonisation was ‘picking winners’ and viewed this as incompatible with the CM’s technology neutrality principles. One response stated that power CCUS and hydrogen to power were the clearest options for low carbon flexible capacity and that hydrogen blending was an iterative step, and another suggested solar and wind might be a better option as costs fall, with the marginal electricity being used to produce synthetic gas.

Other miscellaneous suggestions for the facilitation of decarbonisation included moving the T-4 to ensure a full four years prior to the delivery year, three respondents who sought the improvement of secondary trading rules, the removal of rule 4.4.4, and five year energy reduction targets and/or a carbon quota trajectory tapering to zero by 2035. One respondent also emphasised the need for greater analysis and forecasting of the expected requirement for decarbonisation within the existing CM portfolio.

Questions 16 to 18 sought views on options for providing CMUs pathways to decarbonisation whilst ensuring security of supply. The pathway options on which views were sought were:

- Secondary trading (Q16 – 38 responses)
- Reactive procurement (Q17 – 31 responses)
- Over procurement (Q18 – 34 responses)

Question 16 – Secondary Trading

Of the 38 respondents to the secondary trading option, 18 provided support, or qualified support, for secondary trading as a pathway for decarbonisation. 16 disagreed and a further four respondents did not specify whether they supported or opposed the option.

Respondents who provided support included those that suggested it would incentivise capacity providers to move their shutdowns to seasons where replacement is cheapest and most available, thereby decreasing costs for consumers, and proposed that existing CMUs should either trade directly or be forced to pay the difference. Three respondents noted that it would need to be augmented by an element of reactive procurement (with one also suggesting over procurement), and two respondents identifying a secondary trading auction before winter as potentially useful.

Of those who disagreed, two respondents cited secondary trading as providing inadequate revenue certainty to incentivise decarbonisation, and one respondent suggested that whilst it was unlikely to provide a direct route to decarbonisation, it could facilitate a switch to another support mechanism.

Out of the respondents who did not specify their verdict, two explained that it was difficult to provide an answer given there were several ongoing reforms aimed at improving secondary trading within the CM.

A number of themes were raised throughout the responses, regardless of whether they were for or against secondary trading as a pathway to decarbonisation. Those which provided support caveated their response with issues which they perceived needed to be ironed-out to facilitate this pathway, whilst those which disagreed raised those same issues as reasons for why it was not currently an effective route for existing CMUs to decarbonise.

The most commonly mentioned issue, raised by over half of all respondents to the question, was the lack of liquidity in the secondary trading market. Respondents suggested that due to this constraint, it would only be an effective pathway for small capacity providers. The second most cited issue, raised by 10 respondents, was the perceived need to improve trading rules. A further three respondents suggested specific improvements, with two recommending that

CMUs be able to trade multiple years, and one respondent suggesting that they should be allowed to split their Capacity Obligations between multiple parties to facilitate larger CMUs.

The need to formalise the process was raised by seven respondents who agreed that the current bilateral negotiations should be replaced by a marketplace approach, and that the portal improvement needed to be expedited to facilitate this.

Additional problems with secondary trading, raised by two respondents each, included the view it was an unclear process, particularly in the context of SPD requirements, and that they thought there was insufficient time available to plan a refurbishment due to only being able to trade after the end of a T-1 auction for the following delivery year.

Question 17 – Reactive Procurement

Of the 31 responses to the reactive procurement option, eight respondents agreed it could provide a pathway to CMU decarbonisation whilst safeguarding security of supply, while 18 disagreed. A further five respondents were unclear in their views.

Of the eight which agreed, two felt that reactive trading was likely necessary to respond to reduced CMU capacity after decarbonisation, and another suggested the view that it was the most cost-efficient option for low volumes of capacity. A number of respondents qualified their agreement, with two sharing the view that it would need to operate in conjunction with over procurement, and one respondent saying they felt it should be augmented by secondary trading. Another response shared the opinion that the feasibility of reactive procurement was linked to how much notice capacity providers gave prior to decarbonising.

The most commonly cited reasons by those who disagreed, each raised by three respondents, was the perceived value for money risk for consumers and the view that there was a risk of there not being sufficient visibility of capacity shortfalls for effective procurement. A further two respondents raised that they felt the option was impractical due to the lack of spare capacity.

Those who did not provide clear views included two respondents who requested additional clarity on how reactive procurement would work in practice.

Question 18 – Over Procurement

Out of 34 responses to the option of over procurement, 19 agreed it could safeguard security of supply whilst providing a pathway to decarbonisation, while 10 respondents disagreed. A further five did not specify whether they agreed or disagreed.

Those who agreed raised benefits such as a strong investment signal to low carbon capacity and suggested it would be the best way of guaranteeing security of supply, as well as replacing high volumes of lost capacity. Those who caveated their agreement included four which suggested it could increase costs to the consumer, and one which questioned whether CMU outages weren't already factored into derating factors. Two respondents put forward an alternative whereby the CM has flexible contracts which allows for one or two-year suspensions for which replacement capacity can be procured at no additional cost to the consumer.

Of the 10 respondents which disagreed, the vast majority cited the perceived insufficient cost effectiveness of over procurement, and it’s potential to increase consumer bills. Three respondents also stated they felt that it might be better to use pre-emptive forecasting, relying on capacity providers giving sufficient notice of plans to decarbonise. One respondent felt that the grid often overestimates peak demand, resulting in surplus capacity anyway, whilst others raised alternatives such as the DPA, existing auction interactions, secondary trading, reactive procurement or a combination of all those approaches.

Policy response

The government is grateful for the feedback received to this call for evidence and will continue to draw on the responses received while developing more detailed proposals on specific areas of potential Capacity Market design change. The government intends to progress policy to facilitate the decarbonisation of CMU’s alongside REMA.

Multi-year agreements for low carbon, low Capex thresholds

Questions 19 to 21 consulted on allowing low Capex, low carbon CMUs to be eligible for multi-year agreements. Up to 3-year agreements with no Capex thresholds would be offered to low carbon technologies, such as DSR, which meet the post-2034/35 emissions intensity limit (100g CO_2/kWh).

For some low carbon capacity with lower Capex costs, the requirement to satisfy CM Capital Expenditure (Capex) thresholds in order to secure multi-year agreements disincentivises participation, as these CMUs can only access 1-year agreements, which provide only limited revenue certainty.

The introduction of 3-year agreements would provide greater revenue certainty and is likely to incentivise further low-carbon participation in the CM. This improves market liquidity and achieves a greater diversity of technologies, which strengthens security of electricity supply by limiting the CM’s exposure to issues impacting security of supply, such as gas supplies or high electricity wholesale prices.

Summary of responses

Questions 19 to 21 (44 responses) sought views on

- the introduction of 3-year agreements for low carbon, low Capex CMUs.
- suggestions on alternative approaches.
- any potential consequences or risks that the government should further consider.
- which low carbon technologies might benefit from a 3-year agreement with no Capex threshold.

The questions on the introduction of 3-year agreements for low carbon, low Capex CMUs elicited 44 responses. The majority of respondents identified Demand Side Response (DSR) as an asset type that may take up 3-year agreements, if implemented.

Of the 44 responses received, 21 respondents expressed support, a further seven respondents supported the proposals, but suggested extending the proposal to include refurbishing low-carbon CMUs.

Seven respondents opposed the approach set out in the consultation, whilst others outlined an alternative approach. A further nine responses expressed some approval for action to support decarbonisation but highlighted strong reservations.

There were 15 responses which provided clear support for offering 3-year agreements with no Capex thresholds to low carbon CMUs that satisfy the post-2034/35 Delivery Year emissions intensity limit proposed in section 3.2.2 of the consultation. These responses tended to suggest that offering longer agreements would increase the attraction of the CM to small-scale flexibility solutions and stimulate the growth of innovative and flexible capacity options in the future.

Supportive responses tended to emphasise the view that Demand Side Response (DSR) has a significant role to play in the future electricity system and can support the delivery of net zero targets by providing a legitimate low-cost, low-carbon solution to the issue of providing adequate capacity whilst ensuring security of supply. However, some of the responses that opposed the proposal questioned the reliability of DSR from a security of supply perspective.

Among supportive responses, Capex thresholds were said to be an unnecessary barrier to CM entry for low Capex technologies. It was noted that decentralised and flexible CMUs face indirect costs that are challenging to justify when the CMU can access only 1-year contracts; for example, a need to invest in systems and processes to allow for DSR and the administration required to register for the CM.

Some supportive responses were of the view that providing multiple years of firm revenue would contribute towards making the investment case for DSR more compelling; as greater levels of certainty for asset owners could prompt final investment decisions, in comparison to the 1-year agreements currently accessed by low-Capex Unproven DSR. Some responses called for additional support mechanisms for participants looking to support the ongoing energy transition.

Those opposed to this change held the view that longer agreements were originally introduced to support investments in projects with large Capex requirements and stated that Capex thresholds should remain in place for all technologies.

One respondent pointed to the high clearing prices of the last two T-4 auctions, which should provide sufficient incentive for low-Capex technologies to participate in the CM, even on the basis of 1-year agreements.

Some responses cautioned that government should first assess how 3-year agreements with no Capex thresholds could lead to unnecessary costs to consumers, locking in payments to low Capex technologies at a high clearing price.

Alternatively, a number of supportive respondents suggested that introducing 3-year agreements with no Capex would also increase optionality in the CM, alongside strengthening the CM's resilience by limiting its exposure to threats to security of supply, such as volatile fossil fuel markets or ageing nuclear power stations. Furthermore, another supportive response welcomed the further adoption of basing eligibility for multi-year contracts on creating revenue certainty for CMUs that will contribute to decarbonised security of supply, rather than purely on the basis of Capex thresholds.

In the Section 3.4.2 of the consultation, the government proposed that (in line with existing arrangements for multi-year agreements) only new-build and Unproven DSR (as defined in Regulation 5 of the Regulations) CMUs would be eligible for 3-year agreements with no Capex thresholds. Question 21 asked for respondents' views on which low carbon technologies might benefit from 3-year agreements with no Capex threshold.

The majority of responses identified DSR as an asset type that may take up 3-year agreements, if implemented.

Some responses noted the different nature of various types of DSR, such as vehicle to grid (V2G), domestic DSR and aggregated industrial profiles, noting that the benefits of 3-year agreements might not be universal across all types of DSR. Responses also identified batteries as a likely beneficiary.

A few responses raised additional barriers to CM participation for DSR, such as the administrative processes linked to CM participation and the ability to predict demand more than one year ahead.

Views were mixed as to whether the eligibility for 3-year agreements without Capex thresholds should be expanded to include Refurbishing CMUs.

Seven respondents suggested extending eligibility to include low-Capex low-carbon CMUs, which can demonstrate some investment into refurbishment, improvement or life extension of the asset.

Some responses suggested including units which do not currently hold CM agreements, such as those rolling-off other subsidy schemes such as the Renewable Obligation (RO). It was noted that there could be a positive interaction between 3-year refurbishment contracts with low-carbon assets, as a number of units are starting to come to the end of such RO contracts in 2027.

Responses that supported including refurbishing assets tended to suggest that 3-year CM agreements could potentially be used as a useful mechanism for repowering and extending the life of such assets, which could strengthen security of supply and contribute to bridging the decarbonisation transition.

Beyond extending to refurbishing assets, a number of alternative approaches were suggested. These included introducing an appropriate minimum level of Capex, rather than removing the Capex thresholds entirely. Another approach suggested limiting all CM contracts to a duration of one year, arguing that this would ensure a level playing field across technologies.

Section 3.4.3 outlined the current approach for DSR Testing and FFEDs. The consultation sought views on whether the low carbon intensity limit should take a similar approach to the current emissions reporting regime where each individual component is subject to the emissions limit, rather than the overall CMU.

Responses that addressed this point supported the continuation of the current emissions reporting regime where individual CMU components would be subject to the carbon intensity limit, rather than the overall CMU, as this would prevent any high carbon assets from benefiting from the proposal.

Alongside all of the responses that agreed with the introduction of 3-year agreements with no Capex thresholds for low carbon capacity, one respondent specifically expressed the view that turn-down DSR that relies on behind-the-meter diesel generation should not be eligible. Another respondent recommended a robust system of testing and verification, so that compliance can be appropriately assessed throughout the CM agreement period. Some respondents that suggested extending the proposal to include refurbishing assets, emphasised the importance of implementing a verification process for refurbishing assets wishing to access these 3-year agreements, to mitigate risks around emissions compliance.

More generally, a number of responses referred to the Review of Electricity Market Arrangements (REMA) consultation[6] and urged government to consider how these proposals interact with potential options for CM reform as part of REMA.

Responses also urged government to consider the need for further measures that may be required to ensure flexibility solutions play a key role in the transitioning energy system. One response asked government to consider this question when reviewing responses from the annual review of new technologies[7].

Respondents also observed that, in their view, government was not taking action to address participation barriers for other technologies, such as those with long build times, and challenged this approach.

Other responses asked government to go further on decarbonisation alignment and rapidly initiate a subsequent process to give clarity to developers and investors on the way the market will reward providers of low carbon, dispatchable peak-loading power.

Policy response

In line with the majority view of respondents, the government intends to progress these policy proposals as part of phase 2, with a view to implement from 2024 at the earliest, subject to further analysis and development.

As stated in the 2021 Smart Systems and Flexibility Plan, government is progressing a range of actions to remove barriers and reform markets for flexibility, including adapting the CM to better align with our net zero ambitions. Whilst the government has noted the points made in opposition to this proposal, it continues to believe that offering 3-year agreements with no Capex thresholds would address participation barriers for low carbon capacity, whilst limiting consumer exposure to price, competition and volume risks.

[6] https://www.gov.uk/government/consultations/review-of-electricity-market-arrangements
[7] https://www.gov.uk/government/consultations/capacity-market-new-technologies-2022/open-letter-on-new-technologies-in-the-capacity-market

Capital expenditure thresholds

Questions 22 to 24 consulted on updating the reference cost levels of the CM's Capex thresholds to ensure these thresholds are appropriate for the capacity mix which may be seen in the CM during the transition to a net zero power system.

The thresholds were set in 2013 at £250/kW for a 15-year agreement and £125/kW for a 3-year agreement, but are linked to inflation and so have risen to £280/kW and £140/kW respectively.

The consultation proposed that the reference cost level of a 3-year agreement would be changed to be linked to the cost of refurbishing an Open-Cycle Gas Turbine (OCGT), resulting in a threshold of £135/kW, with the aim of making this threshold more relevant to the types of refurbishments the government are likely to see competing in the CM in the coming decade.

The 15-year agreement threshold was proposed to remain at £280/kW to ensure that a wide range of low carbon technologies can continue to benefit from eligibility for long multi-year agreements to better support their investment case.

Summary of responses

Question 22 (35 responses) sought views on:

- the proposed changes to the reference cost levels underpinning the CM's 3-year and 15-year Capex thresholds.

Question 23 (23 responses) sought views on:

- concerns about the assumptions made regarding the calculation of the revised reference cost levels.

Question 24 (21 responses) sought views on:

- any foreseen unintended consequences which could result from making, or not making, these changes to the 3-year and the 15-year Capex thresholds.

Question 22 on the revision of 3-year and 15-year agreement reference costs levels elicited 35 responses. The majority of respondents supported the proposals, with 25 responses fully agreeing with the proposals and four responses providing qualified support. Responses from three stakeholders opposed the proposals and suggested alternative approaches, whilst the remaining three responses were neutral.

Supportive responses expressed the view that revising the 3-year, and maintaining the 15-year, Capex thresholds was sensible and agreed with the proposed reference cost levels for the thresholds, noting the changing technology mix of the CM and developments in the GB energy system more broadly.

The majority of respondents agreed that the £135/kW Capex Threshold for 3-year refurbishment agreements reflected the most likely refurbishing scenarios and that £280/kW for 15-year agreements best represented the costs of new build plant in the future CM.

A few responses urged government to establish a process for revising the reference cost levels on a regular basis, to ensure these remain applicable and reflect the applicant portfolio of future CM auctions. Some respondents also stated that the cost of low-carbon technologies should be monitored, to ensure that the reference cost levels do not become a barrier to low-carbon technology deployment. One respondent suggested legislating for an annual review of the Capex thresholds.

Respondents who opposed the change tended to disagree that longer-term contracts should be reserved for plants with particular Capex requirements. Suggested alternative approaches urged government to pursue carbon or emissions intensity limits instead of Capex thresholds in any form, to incentivise low carbon technology to participate in the CM.

Some respondents also suggested removing all Capex thresholds, with a view that this would increase competitiveness and encourage a wider range of low-carbon technologies to participate in the CM. Responses that supported such alternative approaches emphasised that emissions limits should be the key criteria for determining access to multi-year agreements.

Another response suggested that government should award 50% of 15-year contracts to CMUs over the Capex threshold, whilst removing the threshold for the remaining 50%. The response also suggested that the Capex threshold for 15-year contracts could remain but be removed for the proposed 9-year contract.

Question 23 asked respondents to share any concerns about the assumptions used to calculate the revised reference cost levels. 23 responses were received, of which the overwhelming majority did not express any concerns, stating that the assumptions better reflected the future technology mix of the GB energy system. Other responses urged government to share further evidence detailing the calculation of the 3-year Capex threshold.

One response questioned whether the reference cost levels for 3-year refurbishment agreements assumed the conversion of an existing CMU into a low-carbon unit, or if the focus was on refurbishing unabated CCGTs and OCGTs to remain unabated. If the former, then the respondent urged government to give further consideration to the level of the threshold and the term of the agreement.

Question 24 sought views on any foreseen unintended consequences which could result from making, or not making, these changes to the 3-year and the 15-year Capex thresholds. Only two respondents detailed their views.

One respondent suggested that retaining Capex thresholds resulted in the CM being biased against low-Capex technologies such as Demand Side Response (DSR), battery storage and solar. They urged government to reform the CM further to encourage the participation of low-carbon capacity. Another respondent emphasised that retaining the existing Capital thresholds for 15-year contracts excluded pumped storage projects from the CM, due to their high Capex.

Policy response

In line with the majority view of respondents, the government intends to progress these changes to the reference cost levels underpinning the CM’s 3-year and 15-year Capex thresholds as part of phase 2, with a view to implement from 2024 at the earliest, subject to further analysis and development.

The government notes that some respondents, for various reasons, questioned the continued use of Capex thresholds. The government still maintains the rationale for reserving the longest agreements for high-capex technologies, which still need to be competitive in CM auctions to support future security of electricity supply, and is therefore minded to retain the use of Capex thresholds in the CM.

9-year capital expenditure threshold

Questions 25 and 26 consulted on the introduction of a new mid-point 9-year Capex threshold. Projects which meet the 9-year Capex threshold would also be required to meet the post-2034 emissions intensity limit proposed in section 3.2.2 of this consultation in order to be eligible for an agreement of up to nine years. This aims to ensure new and refurbishing projects with costs which fall between the existing 3- and 15-year thresholds are not prevented from coming forward in the CM. This will help to support a wide range of low carbon projects for whom existing CM arrangements may not be sufficiently versatile, such as low-carbon refurbishing assets.

Summary of responses

Question 25 (31 responses) sought views on:

- the proposed introduction of a 9-year Capex threshold for low carbon CMUs,
- any foreseen unintended consequences.

Question 26 (28 responses) sought views on:

- the proposed reference cost levels underpinning the 9-year Capex threshold,
- further evidence on alternative reference cost levels.

Question 25 elicited 31 responses, of which 16 expressed clear agreement with the proposals. A further eight respondents provided qualified support, while five opposed the introduction of a new mid-point 9-year Capex threshold, as set out in Section 3.5.2 of the consultation. The remaining two responses did not express a specific view either way.

Supportive responses tended to emphasise the view that a 9-year agreement would provide additional investment security for projects that require significant capital expenditure but do not meet the 15-year threshold. It was noted that this proposal could facilitate the advancement of large-scale decarbonisation measures in both the CM and the wider GB electricity market.

Responses in support of the proposal also noted that the introduction of the 9-year threshold would address current investment challenges for technologies that fall between the existing 3-year and 15-year thresholds. Furthermore, this was recognised as a positive step in increasing the range of contract options available to low-carbon forms of generation, which would allow capacity providers to evaluate a wider range of refurbishment options.

Supportive responses agreed that 9-year Capex thresholds should be reserved for CMUs that can fulfil the government’s definition of low-carbon generation.

One response noted that if the 9-year threshold was introduced, CM Rules relating to Total Project Spend and Extended Years Criteria would also need to be considered, ensuring these reflect the amendment. Further to this response, another respondent encouraged government to undertake a full impact assessment of the proposal, to determine whether implementation of a mid-point Capex threshold would have any wider implications.

Respondents who opposed the introduction of a 9-year Capex threshold were of the opinion that such agreements would disproportionately benefit decarbonising fossil fuel CMUs, at the expense of the development of existing low carbon generation (such as batteries). These respondents urged government to consider the proposal against the technology-neutral principles of the CM.

One response asked government to consider how the introduction of 9-year agreements could create a “two-tier system” between smaller and larger capacity projects. They argued that 9-year agreements could benefit smaller scale assets and limit investment in larger capacity projects, which they believed the GB electricity system needed.

Another response urged government to provide a more detailed explanation or why a 9-year Capex threshold had been proposed, as opposed to other lengths.

More widely, respondents provided general views on Capex thresholds. One response was of the view that Capex thresholds are artificial in nature and may encourage projects to spend more than is required, so encouraged government to allow CMUs to define the length and size of their obligations. Another respondent was of the view that the definitions of project spend are too limiting, which they believed resulted in projects accelerating spending in other areas to meet Capex threshold requirements.

Question 26 elicited 28 responses. Views on the proposed reference cost level underpinning the new 9-year Capex threshold were mixed.

Supportive responses generally did not provide comment or qualification, whilst a number of responses urged government to consider the range of technologies/assets which the new threshold is designed to support and set the reference cost levels appropriately.

One response noted that, in the absence of any technology specific costs and given the uncertainty about which technologies which might consider using this option, the government’s approach to setting the new 9-year Capex threshold represented a reasonable starting point. This response urged government to keep reference costs under review.

An alternative view was provided by a respondent who agreed that multi-year contracts for low-carbon CMUs should be available but disagreed that these should be reserved for high-Capex plant. This response noted that as the proposed 9-year Capex threshold of £205/Kw was calculated using the average of the reference cost levels for the existing 3-year and 15-year Capex thresholds, then the 9-year contracts would likely attract similar types of technologies, as opposed to the low-carbon technologies it is aiming to benefit.

This response also noted that assets which meet the 15-year Capex threshold can already choose to reduce their contract length ahead of the T-4 auction, arguing that many of the benefits of the proposed 9-year contract already exist.

Another respondent noted that the proposed reference cost of £205/kW would still be challenging or unattainable for some low-carbon technologies and asked government to address the CM participation challenges faced by certain low-Capex, low-carbon technologies.

Policy response

The government welcomes the evidence provided in the responses regarding the introduction of 9-year agreements for projects that meet the proposed post-2034 emissions intensity limit. Given the mixed responses received government intends to explore this policy proposal further as part of phase 2, including undertaking further analysis and development.

The government will not progress any changes in relation to these particular matters ahead of 2023 CM prequalification.

Total Project Spend

Question 27 consulted on amending the definition of 'Total Project Spend' such that the window to account for Capex costs for refurbishing units would be aligned with that of new build units, to cover a period of 77 months prior to the commencement of the first Delivery Year. The aim of this change is to enable Refurbishing CMUs to capture their full Capex costs in recognition of the fact that some refurbishments are in practice as complex and intensive as building new capacity (e.g., pumped storage hydropower refurbishments), and that the CM may see more costly and complex refurbishments coming forward as capacity looks to decarbonise in the future (e.g., retrofitting unabated gas plant to fire hydrogen).

Summary of responses

Question 27 (27 responses) sought views on

- proposed changes to the definition of Total Project Spend to extend the scope of the existing permitted period for Capex in respect of new build CMUs (i.e. in effect a 77-month period prior to the commencement of their first Delivery Year) to include Refurbishing CMUs.
- any unintended consequences which could arise from this change.

Of the 27 responses received the overwhelming majority agreed with the proposal, either wholly or in principle, with just two disagreeing and a further two neither agreeing nor disagreeing.

Of those agreeing, 14 respondents did so without qualification, with the remaining eight respondents adding caveats. Respondents urged government to ensure that the proposal does not capture work which capacity providers would have undertaken anyway, without requiring CM support. A few respondents thought there was a need to ensure the measure does not enable the refurbishment of existing fossil generation sites without a clear decarbonisation plan in place.

A respondent who disagreed with the proposal suggested that extending the existing permitted period for Refurbishing CMUs may hinder investment, as applicants might delay refurbishment until an auction with a clearing price that delivers best value, rather than sufficient income.

Two respondents felt that the 77-month window should be reconsidered for new-build projects with longer construction times (such as Pumped Storage Hydro) which would benefit from a project specific window, while one respondent agreed with extending the Capex period to Refurbishing CMUs but opposed the proposed 9-year threshold.

Finally, two respondents noted a similarity between this proposal and Capacity Market Advisory Group proposal CP366, requesting clarification on ownership of CM rule changes in general as well as on this proposal in particular.

Policy response

In line with the majority view of responses, the government intends to progress these policy proposals as part of phase 2, with a view to implement from 2024 at the earliest, subject to further analysis and development.

Two respondents asked government to amend this proposal to address participation barriers for projects with long build times. Policy proposals in relation to projects with long build times are considered in the following section of this consultation response.

Government continues to work collaboratively with the Capacity Market Advisory Group and will address change proposals that interact with policy development when required.

Projects with long build times

Section 3.6 of the consultation outlined how government had identified significant implementation and operational issues which would add additional complexity to all aspects of the CM's operational processes. As such, it stated that government would not currently progress this proposal, instead it would consider feedback and operational challenges further.

Question 28 expanded on the government's position in respect of the introduction of a later first Delivery Year (a 'declared later Delivery Year') for new build Generating CMUs that could suitably evidence that they need more time for construction than the start of the Delivery Year of the T-4 auction.

Summary of responses

Question 28 (24 responses) outlined that:

- the government remains open to considering proposals to address challenges faced by projects with long build times.
- and invited respondents to provide further evidence or proposals that would address such challenges.

The majority of the 24 responses urged government to continue with the development of proposal to allow projects with long build times to be able to participate in the CM. Many of the stakeholder responses received were comprehensive and raised specific points for Government to consider further.

Supportive responses tended to emphasise the view that long duration electricity storage has a significant role to play in providing energy security in the future electricity system, whilst supporting the delivery of net zero targets.

Whilst many responses acknowledged the interaction with the Large-scale Long-duration Electricity Storage (LLES) call for evidence and associated proposals, they urged government to continue with CM amendments simultaneously as it was their view that the policy developed to support LLES is expected to work in harmony with the CM.

A few responses suggested that LLES projects supported by any future policy should still be able to access CM agreements (like interconnectors) to ensure these projects are best able to support GB’s security of supply.

Respondents who did not support the continuation of policy development were of the view that the CM is not an appropriate mechanism to support projects with long build times. One respondent urged government to consider how introducing a declared later delivery year could disrupt the CM auction outcomes, for the vast majority of participants, to accommodate only a small number of projects impacted by this issue.

Three responses suggested that a declared later delivery year could be introduced without distorting the capacity procured or the clearing price, by either:

- Pre-qualifying projects with long build times, but “holding” them outside of the auction. Once the T-4 auction clears, these projects would be offered a contract at the auction clearing price, for delivery from the declared later delivery year.
- Allowing all projects to participate in the T-4 auction but pre-qualify the capacity of projects with long build times as nominal (e.g., sub 1MW), allowing the unit to participate in price discovery without undermining security of supply for the T-4 delivery year.

A few respondents proposed alternative delivery mechanisms, including:

- Amending T-4 auction parameters to over procure capacity to accommodate the CMUs with longer build times.
- The introduction of a third auction, with a demand curve which would account for risks such as non-delivery, low-liquidity and opportunity costs.
- Awarding contracts within the current T-4 auction structure but introducing a cut-off date for making a declaration to defer the contract start to a later Delivery Year.
- The introduction of discretionary powers to allow government to award innovative or capital-intensive projects an additional year at the end of their agreement if they evidenced issues with delivery leading to an agreement of less than 13-years.

A few respondents urged government to move T-4 auctions forward, to ensure that projects benefit from at least 4 years build time before the start of the Delivery Year. It was noted that current timings often result in larger or more complex CMUs delivering by the long stop date, as opposed to the start of the Delivery Year.

Respondents also raised additional challenges for project build-times, including the ability to secure grid connections. One respondent also urged government to extend access to a declared later delivery year to Refurbishing CMUs, noting that whilst the current need for longer build times is very limited this may be more necessary as CMUs start to decarbonise.

The majority of respondents urged government to share additional evidence and provide a clear assessment of all options available, alongside the exact impact these would have on existing operational and administrative requirements. A few respondents acknowledged that progress in this area may be dependent on reforms outside the scope of this consultation, such as policy being developed to support Large-scale Long-duration Electricity Storage (LLES) and the proposals on an “Optimised CM” being considered by the Reform of Electricity Market Arrangements (REMA, Chapter 8).

Policy response

As stated in the recent Powering Up Britain: Energy Security Plan, the government is committed to developing appropriate policy by 2024 to enable investment in large scale long duration electricity storage (LLES), with the goal of deploying sufficient storage capacity to balance the overall system. Based on the feedback received through this consultation, alongside the evidence received through our earlier Call for Evidence on LLES, the government will continue to explore options for addressing the issues faced by projects, of all technologies, with long build times. The government anticipates further consultation in due course.

Additionally, the government intends to review the relevant CM auction timelines, to ensure that projects benefit from the intended build time before the start of the Delivery Year, whilst maintaining the integrity of the CM auctions

Additional improvements to the Capacity Market

This chapter summarises Questions 29 to 34 of the consultation, which considered a range of issues and options related to making appropriate clarifications to the CM Regulations and Rules and to improving and simplifying the CM's design.

Clarifying auction clearing mechanics

Question 29 consulted on clarifying auction clearing mechanics to ensure that the legislation more clearly reflects policy intent and implementation. For scenarios where the auction target exceeds the amount of capacity entered into the auction, each eligible bidding unit should be awarded an agreement, in line with established practise and the CM's objectives to ensure security of supply. This change is being considered in light of requests for clarification of auction mechanics following the T-1 auctions in 2022 where this scenario was observed. This proposed change addresses a practical issue and will improve the efficiency of CM operation.

Summary of responses

Question 29 received a total of 32 responses, all of which supported the proposal. The majority of respondents did not raise any unintended consequences. Two respondents asked the government to consider whether it would be appropriate to introduce a window between prequalification and the capacity auction within which applicants could opt-out of participating in the auction, in line with arrangements for New Build CMUs. These respondents felt this would enable applicants to adapt to updated information on their ability to deliver against obligations, to protect against winning an agreement that cannot be met and be subject to termination.

Policy response

The government welcomes the strong support for the proposed clarification of the auction clearing mechanics. In line with this support, government intends to implement appropriate changes under phase 1.

The government appreciates suggestions on ways in which identified non-delivery risks could be managed prior to capacity auctions, but note that this may have impacts on auction outcomes and security of supply.

Requirements on the Secretary of State in determining whether capacity auctions need to be held

Question 30 consulted on reducing the administration requirements on the Secretary of State to write to confirm that an auction will be held; instead, the Secretary of State will only be required to confirm that an auction will not be held. This is a minor administrative change to make the CM function more efficiently.

Summary of responses

Question 30 received 33 responses, 29 of which supported the proposal, one which did not support the change and three which did not state clear support but raised wider considerations. The majority of respondents agreed with the proposal and did not raise any unintended consequences. Many respondents also expressed the need for a clear timeline regarding the Secretary of State's announcement about whether an auction will be held or not, as this information would be required to inform business decisions. Most of these respondents supported maintaining timelines in line with current arrangements, with a Secretary of State (SoS) announcement by 15 June. A few felt that the deadline for the announcement of SoS's decision to not hold auctions should be earlier to mitigate the risk of preparatory work being undertaken at cost. A few stakeholders also supported a wider review of CM legislation to identify and remove other requirements that may no longer be necessary, to reduce administrative burden on both delivery partners and capacity providers. The respondent who did not support the proposed change believed that the existing announcement of SoS's intention to hold auctions should continue to be made to current timelines, to support investment certainty.

Policy response

The government welcomes the broad support received for this proposal and intends to implement the proposal in line with section 4.3 of the consultation , parliamentary time allowing. The upcoming announcement by SoS for next year's auctions will not be impacted by this change and that announcement will be made by 15 June 2023.

With regards to respondents who supported clear timelines for the announcement to enable appropriate business planning activities, our intention is to maintain timescales for announcements in line with existing requirements under Regulation 10(5). The government does not intend to make a change to require this announcement to be made at an earlier stage at this point, to avoid the risk of impacting on the timelines for delivery of the Delivery Body's Electricity Capacity Report and appropriate considerations by the Panel of Technical Experts and Secretary of State. The government believes that maintaining current timelines for an announcement should provide adequate certainty to enable investment decisions.

Changes to the Capacity Market/Contracts for Difference transfer process

Questions 31 and 32 consulted on amending the CM/Contracts for Difference transfer route to make it operational. The CM Regulations contain an option for certain units to seek the termination of their capacity agreements in order to become eligible to bid in a Contracts for Difference Allocation Round. However, the definition of the required ‘CfD transfer notice’ is drafted such that in practice, Capacity Providers cannot obtain this notice from LCCC (Low Carbon Contracts Company), which prevents them from using this transfer route. Under the proposed change, the ‘CfD transfer notice’ will be redefined to enable providers to utilise the existing transfer route between schemes.

Summary of responses

Question 31 received 28 responses, 12 of which were supportive and five of which offered caveated support, with seven not supporting the proposal. A further four responses did not state whether they supported the proposal but shared other considerations.

A total of 17 respondents supported the proposal, and those that provided qualifying statements welcomed the clarity that the redefinition of the CfD Transfer Notice would bring. Four respondents agreed with the proposal, but felt that the option for voluntary termination of capacity agreements should be extended to other government energy support schemes that are currently not directly referenced in CM legislation, including those that may be available in the future.

Of the seven respondents who did not support the proposal and provided detailed responses, one felt that enabling Capacity Providers to use the CfD transfer route would undermine the certainty in capacity supply in the CM, one did not agree with the principle of voluntary termination and another asked for further assessment of the impacts on security of supply and consumers.

Four respondents did not state clear support or opposition to the proposal, but a few asked for further insight on the potential impacts of the proposal and what technologies might benefit from such a change. One respondent agreed with the principle that participants should not benefit from both CM and CfD support, and another respondent proposed an alternative solution to better align prequalification for both schemes. This respondent considered it would be of benefit for security of supply if Capacity Obligations remained until CfD support is confirmed, at which point the asset would trade its obligation, to mitigate the risk of an asset being terminated but failing to secure CfD support.

Question 32 sought views on whether the proposed amended CM to CfD transfer route should continue to be available for new agreements or be restricted to existing agreements only. Of the 22 responses to this question, 13 supported making the route available to future agreements, four were against, and five did not clearly support or object to the proposal but raised additional considerations. The majority of supportive respondents did not provide justifications, but a few respondents noted uncertainty over future support for low carbon projects, for example due to lack of visibility of CfD pot structures, and indicated support for allowing greater certainty of CfD support before terminating capacity agreements, to provide revenue certainty and avoid knock-on impacts for security of supply. Of the respondents that considered it appropriate to limit the CM to CfD transfer route to existing capacity agreements only, one felt the route should be limited to new build capacity only and another did not agree with the principle of voluntary termination on the basis of competing government support. Other respondents supported fair and practical transfer routes from the CM to CfD, and also considered there to be insufficient evidence to support limiting the route to existing agreements only.

Policy response

In light of the broad support from respondents on question 31, the government intend to implement the amendments to the definition of the CfD Transfer Notice as consulted as part of phase 1 changes, parliamentary time allowing. As noted in section 4.4.2 of the consultation, CMUs intending to utilise this route would be required to withdraw from the CM without certainty of being successful in the relevant CfD Allocation Round, which the government continues to consider to be fair and appropriate. In regard to the feedback from respondents that did not agree with the proposal, the government notes that the change being made is intended to make appropriate amendments to enable an existing transfer route to be used in practise, but that the government intends to monitor the impacts of this change to ensure continued alignment with the core objectives of the CM.

In regards to question 32, the government appreciate the feedback shared on whether the route should continue to be available for new agreements or restricted to existing agreements only. The government intend to continue to explore whether the CM to CfD transfer route remains appropriate for future agreements or if further amendments may be required in the future. Regarding respondents who asked for broader consideration of interactions with other government support schemes, the government intend to keep this under review to ensure continued alignment with Subsidy Control principles and wider energy market developments.

Requirement for Independent Technical Expert assessments for material changes to construction plans

Question 33 consulted on removing Independent Technical Expert (ITE) requirements from construction progress reports. Prospective units (i.e. those that are not yet built) are required to provide updates on construction progress ahead of the Delivery Year to improve delivery assurance. The consultation proposed to make minor amendments to the requirements for construction progress reports, in a way that continues to meet security of supply needs but aims to reduce the cost and unnecessary administrative burden for the relevant units. Affected units would no longer be required to have ‘material alterations’ assessed by an ITE, and would no longer be required to provide an explanation if a Construction Date has moved more than two months earlier than the previous report’s earliest date.

Summary of responses

Question 33 received 30 responses, 27 of which supported the proposal, two which did not support the proposal and one which did not state a position, considering the current arrangements as fit for purpose. The majority of supportive respondents agreed that the change would reduce administrative burden for Prospective CMUs, and a few stakeholders felt that existing ITE requirements for construction reports add significant costs for limited assurance. Other respondents also considered that the change proposed would not risk assurance of construction progress, due to the assurance provided by director signature and then enhanced reporting required if construction dates interfere with Substantial Completion Milestones. One respondent felt that, if the change could not be implemented ahead of 2023 prequalification, the government should instead waive the requirement in line with the proposal to avoid unnecessary administrative costs resulting from a delay to legislative change. The two respondents that disagreed with the proposal did not provide any further information on their position.

Policy response

In line with the majority of support for this proposal, the government intends to implement the changes as consulted through Rules amendments as appropriate under phase one, to reduce administrative burdens on Prospective CMUs.

Temporary rule amendment for Fossil Fuel Emissions Declaration verification deadlines

Question 34 consulted on introducing a phased implementation of emissions verification requirements. This would result in the requirement for Fossil Fuel Emissions Declaration (FFEDs) to be verified by an independent emissions verifier (IEVs) to be delayed by one year to 2024, but with any verifications completed in 2023 remaining valid for the following year (including complex verifications which would usually need to be verified annually). The aim of this temporary rule change is to mitigate the risk, linked to the availability of IEVs and unfamiliarity of the process to CMU providers, that not all applicants would be able to have their emissions verified in time for the 2023 prequalification window, thereby potentially impacting on auction liquidity and security of supply.

The question elicited 27 responses, with 26 respondents supporting the proposal, including 15 which provided caveated support and one respondent which disagreed with the approach.

Many of the respondents who welcomed our approach suggested it mitigated against the risk of Capacity Providers being unable to get verification due to a lack of availability of IEVs and avoided penalising providers who had already secured independent verification, whilst ensuring the security of supply. One respondent caveated their support on the premise that implementation was not delayed any further, to ensure that the CM aligns with decarbonisation commitments and that all parties were aware of the need to meet the requirements before the 2024 prequalification window.

Seven respondents raised concerns about the availability and capacity of IEVs to conduct the verifications ahead of the 2024 prequalification window, with one suggesting that there are insufficient verifiers for the fossil fuel participants in the CM and questioning whether two years is enough time given the current limited numbers of verifiers available. Other respondents cited their experience of verifiers being fully booked. Another suggested that this may introduce risk into the pre-qualification process, providing a hypothetical scenario where a CM participant misses the application window due to a lack of IEV availability.

Other respondents specified concerns about verifiers impeding the overall process and introducing additional costs for CM participants, with one suggesting this may disincentivise smaller generation assets from participating in the CM.

Two respondents raised concerns about the timings of the verification, suggesting that they do not provide useful information at the time of the delivery year, and one suggested that it would be more useful to verify emissions closer to real time. Another suggested that post 2024 verifications could be provided 22 working days before the auction, rather than being required as part of the prequalification process.

Some respondents, while welcoming the proposal, questioned why the Environment Agency (EA) could not act as the verifying body, noting that the EA already monitors and checks the emissions from permitted plants. One respondent questioned why directors could not be trusted to report emissions themselves and suggested that an audit system could be introduced to spot check and identify any concerns.

Finally, two respondents raised wider concerns about whether the CM can provide sufficient assurance that it is on a pathway to decarbonisation and to meet net zero targets.

The respondent that which disagreed suggested the approach does not deliver the policy intent and a phased approach only delays implementation. The respondent went on to suggest that lessons could be learnt through directly delivering the verification process, which may highlight opportunities to make it fit for purpose.

Policy response

The government recognises the concerns raised around the concerns about the capacity and availability of IEV's and will continue to work closely with verifiers and capacity market participants to ensure that these concerns are addressed. However, in line with broad support in the consultation response, government intends to proceed with the proposal for the phased implementation of the IEV requirements. Any verifications completed in 2023 will remain valid for the 2024 prequalification window, including complex verifications which would usually need to be verified annually.

The government strongly encourages Capacity Providers to continue getting their FFED verified this year to avoid oversubscription of the IEVs before the 2024 prequalification window, which could result in emissions not being verified in time and providers failing to prequalify.

Assessment of impacts

This chapter summarises Question 35 of the consultation, which assessed the impacts of each proposal in detail and sought views on whether stakeholders agreed with the consideration of impacts and additional impacts that may not have been considered by government.

Summary of responses

Question 35 received a total of 27 responses, two of which stated clear agreement with the consideration of impacts included in the consultation and 25 of which also shared wider views on the consultation and the CM. Of these 25 responses, five stakeholders broadly agreed with the consideration of impacts. Two respondents commented on the penalty impacts and considered that metered output data referenced under section 5.2 of the consultation does not indicate availability.

The majority of respondents referenced information detailed in responses to specific questions in the consultation. In particular, some respondents emphasised their concerns around the unintended consequences of the changes proposed for SPDs, penalties and some of the decarbonisation proposals. These respondents generally proposed alternative solutions, in line with feedback covered in previous sections of this government response, and called for more supporting evidence to be gathered before implementing changes. A few respondents asked for greater assessment on the potential differential impacts across technology types as well as more information on the impact on suppliers and consumers.

A few respondents raised wider concerns around the CM. These included queries over the wider interactions with the REMA project as well as with other energy market arrangements. Some respondents shared concerns over delays to the Delivery Body's CM portal and the impacts this would have on implementing changes. A few respondents also asked for a review of derating factors, SSE signals and interactions with other support schemes to ensure that the CM framework remains fit for purpose.

Policy response

The government welcomes the feedback shared on the assessment of impacts included in section five of the consultation. Feedback on the assessment of impacts for the penalties, SPDs and decarbonisation proposals will be considered in further detail under phase 2. The government also appreciate the feedback shared by stakeholders more broadly on the CM and will continue to work closely with delivery partners to ensure smooth implementation. In regards, to wider interactions with energy market developments, the government will ensure that future changes to the Capacity Market are considered within the context of REMA's emerging direction of policy.

Glossary

Abbreviation	Definition
Aggregator	An aggregator provides an intermediary service of aggregating DSR capacity from a range of other organisations for the purposes of National Grid ESO Balancing Services or the CM, in return for a share in the revenues generated by those organisations.
Auction clearing price	The price at which the supply of capacity offered by bidders at that price is equal to the volume of capacity required to be secured in the auction.
Auction parameters	The parameters of the capacity auction, which are determined by the Secretary of State. This includes the capacity target, net-CONE, the price-taker threshold, price cap, the capacity margins and the capital expenditure thresholds.
Balancing Services / Balancing Mechanism	The services procured by / mechanism used by National Grid ESO to balance electricity demand and supply across the national transmission network.
Baseload	Electricity generation that is at the bottom of the merit order, i.e. tends to have low short run marginal costs and a high load factor.
Behind the meter generation	DSR that reduces electricity demand on the distribution network or transmission network by starting up on-site generators to provide electricity. Also known as generation derived DSR.
Cap and Floor	A scheme designed to incentivise investment in interconnectors between GB and other countries by reducing uncertainty in electricity prices for interconnectors.
Capacity	An amount of electrical generating capacity or DSR capacity, usually expressed in megawatts (MW) unless stated otherwise.
Capacity Agreement	The rights and obligations accruing to a capacity provider under the Regulations and the Rules in relation to a CMU for one or more delivery years.
Capacity Auction	An auction held under Part 4 of the Regulations, as a result of which successful bidders are awarded capacity agreements.
Capacity Market Notice (CMN)	A signal issued by National Grid ESO four hours in advance that there may be less generation available than expected to meet national electricity demand on the transmission system. Rule 8.4 of the Capacity Market Rules describes the specific obligations to be met by a Capacity Provider, including where a System Stress Event occurs, and the procedures for determining when a System Stress Event has occurred and for issuing a Capacity Market Notice.

Abbreviation	Definition
Capacity Market Rules/ CM Rules ("the Rules")	The Capacity Market Rules provide the technical detail for implementing the operating framework set out in the Regulations.
Capacity Market Unit (CMU)	A unit of electricity generation capacity or DSR capacity that can be put forward in a capacity auction. It is the product that forms the capacity to be purchased through the CM.
Capacity Obligation	An obligation awarded pursuant to a capacity auction, applying for one or more delivery years, to provide a determined amount of capacity when required to do so in accordance with Capacity Market Rules.
Capacity Payment	A payment to a capacity provider under the Regulations for its commitment to meet a Capacity Obligation during a delivery year.
Capacity Provider	A person who holds a capacity agreement or a transferred part in respect of a capacity agreement.
Capital expenditure thresholds (Capex)	Auction parameters that determine whether a CMU can access a multi-year agreement (either as a refurbished CMU or a new build CMU) based on their amount of capital expenditure (in £/kW).
Carbon Capture, Utilisation and Storage (CCUS)	The process of capturing carbon dioxide from industrial processes, power generation, certain hydrogen production methods and greenhouse gas removal technologies such as bioenergy with carbon capture and storage and direct air capture. The captured carbon dioxide is then either used, for example in chemical processes, or stored permanently in disused oil and gas fields or naturally occurring geological storage sites.
Combined Cycle Gas Turbine (CCGT)	An electrical power plant in which a gas turbine and a steam turbine are used in combination to achieve greater efficiency.
Combined Heat and Power (CHP)	An electricity generating unit that also supplies heat.
Connection Capacity	The capacity available to a CMU on the distribution or transmission network.
Connection Entry Capacity (CEC)	Has the meaning given to that term in section 11 of the CUSC (where CUSC is the Connection and Use of System Code)
Contracts for Difference (CFDs)	CFDs are 15-year private law contracts between low carbon generators and the Low Carbon Contracts Company. CFDs stabilise revenues for generators at a fixed price level, set by the government (the 'strike price'). Generators receive revenue from selling their electricity into the market as usual, but when the market reference price is below the strike price they receive a top-up payment. If the reference price is above the strike price, the generator must pay back the difference.

Abbreviation	Definition
Credit Cover	A letter of credit or cash deposit required to be provided by a person (a prequalification applicant, a capacity provider or a supplier) to the Settlement Body. The Settlement Body may draw down on credit cover in certain circumstances set out in the Regulations and the Supplier Payment Regulations, e.g. if the person must pay the Settlement Body a termination fee in relation to the termination of a capacity agreement.
Decarbonisation	A process of reducing the amount of carbon dioxide released into the atmosphere.
Delivery Assurance	An umbrella term that refers to the framework of checks and balances that are used to ensure that CMUS are available to deliver their Capacity Obligation at the start of and during the delivery year. This includes processes in the lead up to the delivery year, such as termination events and the posting of credit cover, as well as processes within the delivery year such as satisfactory performance days.
Delivery Body	The national electricity system operator (i.e. National Grid ESO).
Delivery Partners	Refers to Ofgem, the Settlement Body and the Delivery Body.
Delivery Year	In relation to a capacity auction, this means the year for which a 1-year Capacity Obligation is awarded, or the first year of the period for which a multi-year Capacity Obligation is awarded. Delivery years run 1st October- 30th September of each calendar year. The delivery year 2022/23 commences on 1st October 2022.
Demand Side Response (DSR)	DSR is a method of reducing electricity demand. This can be achieved by either reducing demand by switching off assets (see turn-down DSR), or by starting up on-site generators to provide electricity in place of drawing it from the distribution network or transmission network (see behind the meter generation).
Demand Side Response (DSR) Component	A constituent component of a DSR CMU. DSR CMUs are typically made up of multiple components that are aggregated together to form a single CMU.
Demand Side Response (DSR) Tests	Tests carried out to ensure that DSR capacity providers are on track to deliver their Capacity Obligation before the start of the delivery.
De-rated Capacity	The capacity that a CMU is likely to be technically available to provide at times of peak demand, which is specific to the CMU’s technology type and individual characteristics.
De-rating Factor	A factor that is applied to a CMU’s capacity to derive its de-rated capacity.

Abbreviation	Definition
Distribution Network	This consists of smaller and lower-voltage ‘local’ networks (compared to the high-voltage transmission network). It is used to carry electricity from the high voltage transmission network to industrial, commercial and domestic users.
Electricity Market Reform (EMR)	A programme created by BEIS (formerly DECC) to deliver secure electricity supply and new low carbon generation. It consists of four mechanisms: Contracts for Difference, the Capacity Market, Carbon Price Support and an Emissions Performance Standard.
Electricity Settlements Company (ESC) / Settlement Body	Referred to in the CM legislation as the “Settlement Body”. A private limited company owned by the Secretary of State for the Department, established to oversee the settlement of payments to and from suppliers and capacity providers such as the supplier charge and capacity payments.
Electricity Systems Operator (ESO) / National Grid Electricity Systems Operator	The organisation operating the national electricity transmission network for GB.
Emissions Trading Scheme (ETS)	A method of putting a price on emissions. A cap is set on the total amount of certain greenhouse gases that can be emitted by participants. The cap is reduced over time so that total emissions fall. Within the cap, companies receive or buy emission allowances, which they can trade with one another as needed.
Extended Performance Test (EPT)	Requires a CMU from a Storage Generating Technology Class with an agreement awarded after 21 December 2017 to generate continuously at an average of their Connection Capacity multiplied by Technology Class Weighted Average Availability for a number of consecutive Settlement Periods equivalent to the CMU’s storage duration. This test is taken at one of the CMU’s three Satisfactory Performance Days in the winter of the CMU’s first Delivery Year and must be repeated once every three years thereafter.
Flexibility	The ability to change generation and/or demand in response to an external signal (e.g. price or contract terms). Flexibility enabling technologies include batteries, demand side response, interconnectors and fossil fuel generators.
Fossil Fuel Emissions Declaration	Information provided to demonstrate compliance with the carbon emissions limits in respect of relevant Fossil Fuel Components comprised in a CMU. Exhibit ZA in the Capacity Market Rules sets out the content and form in which the declaration must be provided.

Abbreviation	Definition
Generator	(i) Any equipment that produces electricity, including equipment which produces electricity from storage; and (ii) A business which operates such equipment.
Gigawatt (GW)	A unit of capacity (1000 Megawatts)
Independent Emission Verifiers (IEVs)	An individual who independent of the Applicant or Capacity Provider and is engaged by them to check calculations of Fossil Fuel Emissions and suitably accredited. If established in the UK, they must be accredited by the United Kingdom Accreditation Service (UKAS).
Interconnector	(i) A physical link that allows for the transmission of electricity across GB's borders; and (ii) A business which operates such equipment.
Kilowatt (kW)	A unit of capacity (1000 watts)
Load Factor	The proportion of total hours that an energy generation resource runs throughout the year.
Large-Scale, Long-duration electricity storage (LLES)	Technologies that can store and discharge energy over longer periods of time, such as Pumped Storage Hydropower. These technologies could provide an important role in decarbonising the energy system by storing excess renewable power when output is high and discharging it over periods of low wind generation.
Maximum Export Capacity (MEC)	The maximum amount of capacity a CMU can export to the distribution network, as defined in the CMU's Distribution Connection Agreement.
Megawatt (MW)	A unit of capacity (1000 kilowatts)
Merit Order	A way of ranking available sources of energy, especially electrical generation, based on ascending order of price (which may reflect the order of their short-run marginal costs of production) together with amount of energy that will be generated.
Mid-merit	Refers to plants that fall in the middle of merit order (i.e. plants that tend to have short-run marginal costs and load factors that are neither relatively low nor high).
National Grid Electricity System Operator (NGESO) / Electricity System Operator (ESO)	The organisation operating the national electricity transmission network for GB.
Net Capacity Obligation	Total Capacity Obligation for a CMU following any secondary trades.
Net Zero	Refers to a point at which the amount of greenhouse gas being put into the atmosphere by human activity in the UK equals the amount of greenhouse gas that is being taken out of the atmosphere.
Net Zero Growth Plan	https://www.gov.uk/government/publications/powering-up-britain/powering-up-britain-net-zero-growth-plan

Abbreviation	Definition
New build capacity / New build generator / New build generation	Generators that are to be or are being constructed.
New build CMU	A generating CMU that is not built at the time of the relevant capacity auction.
Open Cycle Gas Turbine (OCGT)	A combustion turbine plant fired by liquid fuel to turn a generator rotor which produces electricity.
Operating Expenditure (Opex)	The ongoing day-to-day cost for running a product, business or system.
Ofgem	A non-ministerial government department and an independent regulator, governed by the Gas and Electricity Markets Authority. Ofgem's powers and duties in relation to the CM are provided for in Chapter 3 of Part 2 of the Energy Act 2013 (c. 32), the Regulations and the Capacity Market Rules, in which it is referred to as "the Authority".
Peaking Capacity	Electricity generators that do not normally operate but are ready to do so when needed at times of peak demand or low generation.
Penalty regime	The regime of financial penalties that are applied to capacity providers who do not provide their committed capacity during a system stress event.
Prequalification	The process set out in the Capacity Market Rules for the Delivery Body to confirm whether a CMU may bid in a capacity auction. A CMU must meet the requirements specified in the Regulations and the Capacity Market Rules to be prequalified.
Prequalification Window	For any Capacity Auction, the period specified in the Auction Guidelines within which applications for prequalification are to be made.
Pumped Storage Hydropower (PSH)	PSH is a storage technology that stores energy in the form of gravitational potential energy of water, pumped from a lower elevation reservoir to a higher elevation.
Refurbishing Capacity Market Unit (CMU)	An Existing CMU which is the subject of an Application as a Prospective CMU by virtue of an improvements programme that will be completed prior to the commencement of the first relevant Delivery Year.
Review of Electricity Market Arrangements (REMA)	The Government has launched the Review of Electricity Market Arrangements (REMA) following commitment in the British Energy Security Strategy. REMA is a major review into Britain's electricity market design to radically enhance energy security and to help deliver our world-leading climate targets whilst reducing exposure to international gas markets.
Satisfactory Performance Days (SPDs)	Days within the delivery year in which capacity providers must demonstrate that they are able to deliver their Capacity Obligation.

Abbreviation	**Definition**
Secondary Trading	Trading by capacity providers in respect of the Capacity Obligations they hold. Takes the form of obligation trading or volume reallocation.
Settlement Period	A period of 30 minutes beginning on an hour or half-hour.
System Stress Event (SSE)	A SSE occurs when demand for electricity outstrips supply; it is defined in Rule 8.4.1 of the Rules.
T-1 auction	This is the capacity auction held one year ahead of the delivery year, which 'tops up' any capacity secured in the relevant T-4 auction.
T-4 auction	This the capacity auction held four years ahead of the delivery year, which secures the large majority of capacity needed in the relevant delivery year.
Termination	In order to prevent speculative bidding and create strong incentives for new build CMUs to deliver new capacity on time, new build capacity and unproven DSR that is not on track to deliver in time for the delivery year may have its capacity agreement terminated, resulting in termination fees.
The Electricity Capacity Regulations ("the Regulations")	This refers to the Electricity Capacity Regulations 2014, S.I. 2014/2043, the principal regulations underpinning the CM.
Transmission Entry Capacity (TEC)	The total amount of capacity that a transmission connected energy resource requires on the network.
Transmission Network	This is the high-voltage electricity network that transmits large quantities of electricity over long distances across the country (cf. distribution network).
Turn-down Demand Side Response (DSR)	DSR that reduces electricity demand by temporarily switching off generators.
Unabated (gas) generation	Electricity generation where carbon dioxide from burning natural gas is not captured and stored.
Unproven Demand Side Response (DSR)	DSR that has not yet demonstrated it has the necessary metering in place or demonstrated it can deliver a specified level of capacity.
Wholesale electricity Market	The market in which generators sell electricity to suppliers.
Winter	A period from 1 October to the following 30 April.

ANNEX A – List of respondents

Only organisations that gave permission for their response to be made public have been included on the list below. Responses received from organisations that did not give permission for their response to be made public; or organisations that indicated they do not want identifying information published; or from individuals, have been taken into account but are not included on the list below.

Association for Decentralised Energy	BEAMA
British Hydropower Association	Carbon Capture and Storage Association (CCSA)
Carbon Tracker Initiative	Centrica
Citizens Advice	CMAG
Conrad Energy Ltd	Drax Group plc
EDF	Energy UK
Engie	EON
EP UK Investments	ESO (EMR Delivery Body)
FGG (Flexible Generation Group)	FORSA Energy
General Electric	Green Alliance
Hydrogen UK	Infinis
Invinity Energy System	InterGen
Mares Connect Ltd	Mercia Power Response
Mobile UK	Moltex Flex Ltd
Mutal Energy	National Gas Transmission
National Grid Interconnectors	Next Energy Capital (NEC)
Ocean Winds	Octopus Energy
OVO Energy	Piclo
Regen	Renantis UK Ltd

Renewable UK	RWE
Scottish Power	Scottish Renewables
Shell	SSE
The Association for Renewable Energy and Clean Technology (REA)	Uniper
WWF-UK	Zenobe

This publication is available from: www.gov.uk/government/consultations/capacity-market-consultation-strengthening-security-of-supply-and-alignment-with-net-zero

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