Department for
Business, Energy
& Industrial Strategy

Capacity Market: Improving delivery assurance and early action to align with net zero

Call for Evidence

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Any enquiries regarding this publication should be sent to us at:
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Contents

Executive Summary

The Capacity Market is at the heart of the government's strategy for ensuring security of electricity supply. It is technology neutral, with existing generators competing against a range of other technologies to obtain agreements under which they commit to making their capacity available when needed, in return for guaranteed payments.

In our Five-year Review,[1] published in 2019, we committed to retaining the Capacity Market as a guarantee of system reliability and to making further incremental improvements to its design. The next full review will need to take place by 2024. This Call for Evidence outlines our initial plans for conducting the Ten-year Review and is intended to kick start our engagement with stakeholders on the longer-term future of the Capacity Market.

Ahead of the Ten-year Review, there is a need to make further incremental improvements to the Capacity Market's design, including those identified through the Five-year Review in 2019. However, we also need to account for a range of important developments, in particular:

- The increasing challenge of maintaining security of electricity supply, both in light of the growing proportion of intermittent renewable capacity on the system and the retirement of our aging generation infrastructure;
- The increased ambition to deliver our legally binding commitment to net zero, exemplified by the publication of the Energy White Paper in December 2020, which outlines the importance of decarbonising the electricity system;[2]
- The new context concerning the possible implementation of direct cross-border participation in the Capacity Market, which has been impacted by EU Exit and the end of the Transition Period, such that we now have the opportunity to consider a range of policy options for the future direct participation of overseas generation in the GB Capacity Market.

This Call for Evidence seeks views on potential early actions, ahead of the Ten-year Review, to align the Capacity Market with net zero and to address increasing security of supply challenges.

Early action to align the Capacity Market with net zero

- **Agreement lengths**: we outline a range of possible amendments to the eligibility criteria for multi-year capacity agreements.
- **Projects with long build times**: we consider ways to better enable low carbon technologies with long build times, such as Pumped Hydro Storage, to access the Capacity Market.

[1] https://www.gov.uk/government/publications/capacity-market-5-year-review-2014-to-2019
[2] https://www.gov.uk/government/publications/energy-white-paper-powering-our-net-zero-future

- **Split auctions**: we discuss whether split auctions are necessary to support firm, low carbon capacity to compete in the Capacity Market.

Strengthening incentives for capacity to deliver when needed and improve delivery assurance

- **Non-delivery penalties**: we put forward considerations for strengthening the penalty regime to address concerns that non-delivery penalties do not adequately incentivise delivery during stress events.
- **Connection capacity:** we consider ways to strengthen checks on Connection Capacity to address concerns around some capacity providers potentially circumventing the effects of de-rating by artificially inflating their Connection capacity.
- **Secondary trading**: we consider enabling a third party to re-auction any remaining capacity obligation associated with a Capacity Market Unit (CMU) that has been terminated during the delivery year or between a capacity auction and the start of the relevant delivery year.
- **De-rating factors**: we look at the possibility of altering de-rating factors for ageing plants to account for their likely reduced reliability.

The benefits of pursuing direct cross-border participation relative to alternative options, considering the new trading and subsidy control arrangements in place following EU Exit

- **Direct cross-border participation**: we outline our position on direct cross-border participation now that we are no longer obliged to implement direct cross-border participation in the GB Capacity Market following the end of the transition period.
- **Cross-border policy options**: we consider possible future policy options on cross-border participation, including the participation of interconnectors in the GB Capacity Market.

1. Introduction

1.1 Background

The Capacity Market is at the heart of the government's approach to ensuring a secure and reliable electricity system. The Capacity Market provides all forms of capacity capable of contributing to security of supply with incentives to be on the system and to deliver during periods of electricity system stress – for example, during cold, still periods when demand is high and wind generation is low.

In 2019, we published our Five-year Review of the Capacity Market[3] (the 'Five-year Review'), which found the Capacity Market was working effectively against its three objectives, namely: incentivising sufficient investment in capacity to ensure security of electricity supply; ensuring the most efficient level of capacity is secured at minimum cost to consumers; and avoiding unintended consequences. We concluded there was a strong need for continuation of the Capacity Market. The next full review will need to take place by 2024 (the 'Ten-year Review'). Through this Ten-year Review, we will explore the Capacity Market's potential to act in concert with other markets to incentivise investment in the right type of capacity, in the right place at the right time.

The Five-year Review identified several potential improvements to the Capacity Market. Several high priority improvements were introduced through legislative changes resulting from the 2020 consultation on Future Improvements, Emissions Limits and Coronavirus Easements ('the Future Improvements Consultation').[4] This included introducing carbon emissions limits, reducing the Minimum Capacity Threshold, and making changes to better facilitate Demand Side Response (DSR) participation. We also set out plans to consider a range of further improvements to the Capacity Market, including (but not limited to) reviewing agreement lengths for all technologies, strengthening the penalty regime, considering changes to secondary trading, reconsidering the potential benefits of split auctions, and planning for direct participation of overseas capacity.

In this Call for Evidence, we return to these challenges and improvements and account for developments which have occurred since the publication of the Five-year Review in 2019. In particular, we consider the emerging security of supply challenges, the acceleration of the decarbonisation agenda, and the changing context of the Capacity Market's future design following EU Exit.

[3] https://www.gov.uk/government/publications/capacity-market-5-year-review-2014-to-2019
[4] https://www.gov.uk/government/consultations/capacity-market-proposals-for-future-improvements

1.1.1 Capacity mix and security of supply

The make-up of Great Britain's capacity mix has changed significantly in recent years. Since 2010, renewable capacity has grown fourfold,[5] significantly increasing the quantity of intermittent and inflexible capacity on the system. This has introduced challenges to ensuring security of supply for those periods when renewable output is lower, such as still winter nights. Additionally, a lot of thermal capacity is nearing the end of its operational life, which may affect its reliability.

The impacts of these trends were visible over the 2020/21 Delivery Year, with tighter margins observed at times between capacity available and electricity demand. This was exemplified between November 2020 and January 2021 by six Electricity Margin Notices (EMNs) being issued by National Grid Electricity System Operator (NGESO) for the first time since 2016, in addition to two Capacity Market Notices (CMNs). Whilst all notices were withdrawn as more capacity became available, the need for NGESO to issue them highlights the tighter margins and the need for Capacity Market delivery incentives to be robust enough to ensure capacity is available when required.

1.1.2 Net zero

Since the publication of the Five-year Review, our ambition to reduce our contribution to climate change has increased. In June 2019, the UK became the first major economy in the world to pass laws and introduce a target to bring all greenhouse gas emissions to net zero by 2050, compared with the previous target of at least 80% reduction from 1990 levels.[6] The Energy White Paper, published in December 2020, highlights the power sector's pivotal role in delivering net zero, including through supporting the electrification of cars and vans and an increase in electric heating usage.[7] In April 2021, the government legally committed to Carbon Budget Six,[8] adopting the Climate Change Committee's recommendation of a 78% reduction in CO2 emissions by 2035 relative to 1990 levels.[9]

Our modelling suggests that overall electricity demand could double by 2050,[10] and that we must aim for a low carbon, reliable, and cost-effective power system by 2050. Furthermore, in the coming decade, over 20GW of existing capacity is likely to retire. The majority of GB's nuclear fleet is expected to retire by the end of the decade, along with the closure of coal-fired generation by 2024,[11] and many gas-fired plants are also coming to the end of their operational lives. We will therefore need to bring forward a potentially significant amount of new build capacity over the coming decade. As noted in Section 1.1.1, the increasing volume of renewable capacity on the system is creating security of supply challenges, and so a

5 Renewables include wind, natural flow hydro, solar, wave, tidal and bioenergy (including co-firing) https://www.gov.uk/government/statistics/electricity-chapter-5-digest-of-united-kingdom-energy-statistics-dukes
6 https://www.gov.uk/government/news/uk-becomes-first-major-economy-to-pass-net-zero-emissions-law
7 https://www.gov.uk/government/publications/energy-white-paper-powering-our-net-zero-future
8 https://www.gov.uk/government/news/uk-enshrines-new-target-in-law-to-slash-emissions-by-78-by-2035
9 https://www.theccc.org.uk/publication/sixth-carbon-budget/
10 https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/947439/energy-emissions-projections-2019-annex-o-net-zero-power-sector-scenarios.pdf
11 https://www.gov.uk/government/consultations/early-phase-out-of-unabated-coal-generation-in-great-britain

proportion of this new build capacity will need to be firm, dispatchable generation (i.e. capacity which can be guaranteed to be available when required) to complement intermittent renewables.

As noted in the Energy White Paper, by 2050 we expect low carbon capacity such as hydrogen-fired generation and CCUS-enabled generation to meet peak demand, alongside flexible technologies such as long duration storage (our analysis also indicates that unabated gas operating at lower load factors may be consistent with achieving net zero in some scenarios).[12] However, we do not anticipate these technologies being deployed at scale before the 2030s. Until then, much of the demand for new build capacity is therefore likely to be met by more carbon intensive forms of generation such as unabated gas-fired generation. Consequently, a key challenge is to ensure that whilst the Capacity Market must continue to be capable of supporting investment in the new build higher carbon generation to ensure security of supply in the short-medium term, we also need to avoid locking in high carbon capacity which is difficult to decarbonise and could increase costs in the long term. Additionally, we need to ensure the Capacity Market is open to and can support investment in less carbon intensive forms of firm, dispatchable capacity.

1.1.3 EU Exit

Following the end of the UK-European Union (EU) Withdrawal Agreement Transition Period (“the Transition Period”) at 11pm on 31 December 2020, the Capacity Market operates under new trading arrangements with the EU under the terms of the UK-EU Trade and Cooperation Agreement (TCA). The government has also recently consulted on the design for a new domestic subsidy control framework.[13] These changes present new opportunities for implementing different design choices for the Capacity Market in future.

1.2 Capacity Market Call for Evidence

This Call for Evidence provides a basis for engaging with stakeholders on potential short and longer-term considerations for improving the design of the Capacity Market. In particular, we intend to explore:

- **Early action to align the Capacity Market with net zero.**
- **Strengthening incentives for capacity to deliver when needed and improve delivery assurance.**
- **Plans for conducting a Ten-year Review of the Capacity Market.**
- **The benefits of pursuing direct cross-border participation relative to alternative options.**

[12] To note, this analysis was carried out before the government’s adoption of Carbon Budget Six in 2021. https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/947439/energy-emissions-projections-2019-annex-o-net-zero-power-sector-scenarios.pdf

[13] https://www.gov.uk/government/consultations/subsidy-control-designing-a-new-approach-for-the-uk

Considerations for aligning the Capacity Market with net zero and improving delivery assurance are summarised below. These are separated into short-term and long-term considerations (i.e. pre- and post- Ten-year Review). The short-term considerations cover potential changes which could be developed into more substantial proposals for consultation and implemented by prequalification in 2023 to help align the Capacity Market with our net zero ambitions and improve delivery assurance. Meanwhile, the longer change considerations focus on potential areas of more fundamental Capacity Market design changes.

1.3 Short Term Considerations

1.3.1 Early action to align the Capacity Market with net zero

The Capacity Market is technology neutral, meaning it does not seek to procure specific volumes of capacity from particular types of technology. All types of capacity are able to participate (except for capacity providers in receipt of other specific categories of government support), but must demonstrate sufficient technical performance to contribute to security of supply. Whilst the Capacity Market has seen growing participation in recent years from low carbon forms of generation such as wind and solar renewables, electricity storage, and some types of Demand Side Response (DSR), it has historically secured predominantly carbon intensive forms of generation, particularly unabated gas-fired generation. For example, about two thirds of capacity with agreements for Delivery Year 2024/25 is gas fuelled. Alongside other high carbon forms of generation, unabated gas generation plays an essential role in ensuring security of electricity supply by providing flexible firm generation when renewable output is low.

As outlined in the Energy White Paper and in the Climate Change Committee’s report on the Sixth Carbon Budget,[14] there is a strong need to decarbonise the power sector in order to meet net zero. The government is taking steps to support this transition, for example via the review of the Carbon Capture Readiness (CCR) guidance announced in the Energy White Paper and published in July 2021.[15] There are also several other key workstreams – including the Contracts for Difference scheme, the development of a Dispatchable Power Agreement to support the deployment of CCUS, and the development of business models to support the deployment of hydrogen – which outline the actions government is already taking and could take in the future to support the decarbonisation of the power sector and maintain security of supply.

In this Call for Evidence, we seek views on the early actions we could take to align the Capacity Market with net zero, whilst continuing to maintain security of electricity supply at least cost to consumers, noting that we also need to consider how any changes made to the

[14] https://www.theccc.org.uk/publication/sixth-carbon-budget/
[15] https://www.gov.uk/government/consultations/decarbonisation-readiness-call-for-evidence-on-the-expansion-of-the-2009-carbon-capture-readiness-requirements

Capacity Market could interact with other policy developments aimed at decarbonising the power sector.

The second chapter of this Call for Evidence sets out in more detail our current thinking on the Capacity Market's interactions with the net zero agenda, and seeks views on potential areas of change to support net zero, including:

- **Agreement lengths**: we consider a range of possible amendments to the eligibility criteria for multi-year capacity agreements.
- **Projects with long build times**: we consider ways to enable low carbon long-build time technologies such as Pumped Hydro Storage to access the Capacity Market.
- **Split auctions**: we discuss whether split auctions are necessary to enable firm, low carbon capacity to compete in the Capacity Market.

1.3.2 Improving Delivery Assurance

Since the Capacity Market was originally developed, the GB electricity system has undergone a significant transformation. In 2010, renewables accounted for 7% of electricity generation, but this proportion has since grown to over one third. While this is a positive step in terms of decarbonisation, we also need to ensure that sufficient flexible and dispatchable generation is available to complement more intermittent renewables and ensure security of supply.

There has also been an increase in distribution-connected capacity on the system, and at present National Grid Electricity System Operator (NGESO) has limited visibility of this type of generation. It is uncertain what volume of capacity with Capacity Market agreements is not currently visible to NGESO, as cross-referencing the Capacity Market register with NGESO's other contracted services is highly complex. However, around 8GW of distributed capacity holding a Capacity Market agreement for Delivery Year 2024/25 is not using a metering system registered in the Central Metering Registration Service (CMRS) and therefore may not be visible to NGESO, compared to around 4GW for Delivery Year 2018/19. From a security of supply perspective, it is increasingly important that NGESO has greater visibility of all generation on the network in order to accurately assess the risk of potential stress events. This is particularly true in light of the security of supply challenge which could arise as a significant proportion of large generators (including most nuclear plants and all unabated coal-fired plants) come to the end of their operational lives.[16]

[16] We recently consulted on proposals to address concerns about the visibility of capacity to the NGESO, including a proposal to require all Capacity Market Units (CMUs) to register as Balancing Mechanism Units (BMUs), which we are working to bring forward in the future – see the following link for more details: https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/994995/capacity-market-2021-consultation-improvements-government-response.pdf

It is also important that we have confidence that capacity secured through the Capacity Market will be available when called upon to deliver in a System Stress Event.[17] Indeed, the need for this confidence was illustrated by the greater non-delivery of capacity and by the tighter margins observed over winter 2020/21 (although the government's Reliability Standard of three hours Loss of Load Expectation (LOLE) was still achieved),[18] which were exemplified by an increase in the number of Electricity Margin Notices and Capacity Market Notices issued, and by more volatile wholesale prices.

The third chapter of this Call for Evidence therefore seeks views on areas of consideration to help improve assurance that capacity will deliver when needed, including:

- **Non-delivery penalties**: we put forward considerations for strengthening the penalty regime to address concerns raised in the Five-year Review that non-delivery penalties do not adequately incentivise delivery during stress events.
- **Connection capacity:** we consider ways to strengthen checks on Connection Capacity to address concerns around some capacity providers potentially circumventing the effects of de-rating by artificially inflating their Connection capacity.
- **Secondary trading**: we consider enabling a third party (such as the Delivery Body) to re-auction any remaining capacity obligation associated with a Capacity Market Unit (CMU) that has been terminated during the delivery year or between a capacity auction and the start of the relevant delivery year.
- **De-rating factors**: we look at the possibility of altering de-rating factors for ageing plants to account for their likely reduced reliability.

1.4 Longer-Term Considerations

1.4.1 Capacity Market Ten-year Review

In line with our statutory requirement, we are commencing our review of the Capacity Market to determine how it has performed against its core objectives. This will culminate in a report to Parliament by Summer 2024. In reviewing the Capacity Market against its core objectives, we will also consider how it has supported the decarbonisation of the power sector. This review will act as an evidence base to inform longer term work on the Capacity Market's future design.

1.4.2 Future Capacity Market Design

Following the UK Government's net zero commitment and the evolving needs of the GB electricity system, we believe it is appropriate to start considering longer-term reforms to the

[17] 'System Stress Event' is defined in Rule 8.4.1 as: a Settlement Period in which a System Operator Instigated Demand Control Event occurs where such event lasts at least 15 continuous minutes (whether the event falls within one Settlement Period or across more than one consecutive Settlement Periods, and where the event falls across multiple consecutive Settlement Periods, each of those Settlement Periods will be a System Stress Event).
[18] Loss of Load Expectation (LOLE) represents the number of hours per year in which, over the long-term, it is statistically expected that supply will not meet demand.

Capacity Market, in conjunction with other work on wider market reforms. This Call for Evidence marks the start of our engagement process, outlining how we will progress the workstream to action changes building on the evaluation of the historic performance of the Capacity Market.

1.5 Direct Cross-Border Participation

We have been taking steps to implement direct cross-border participation in the Capacity Market in line with the requirements under the EU Electricity Regulation 2019 which came into force on 1 January 2020. EU Exit and the end of the Transition Period[19] have significantly altered the context for this, and we now have the opportunity to consider alternative timelines and approaches for implementing direct cross-border participation in the GB Capacity Market to those outlined in Article 26. The fifth chapter of this Call for Evidence examines:

- **Direct cross-border participation**: we outline our position on direct cross-border participation now that we are no longer obliged to implement direct cross-border participation in the GB Capacity Market following the end of the transition period.
- **Cross-border policy options**: we consider possible future policy options on cross-border participation, including the participation of interconnectors in the GB Capacity Market.

1.6 Next Steps

This Call for Evidence is the first stage in exploring potential reforms to the Capacity Market to support the delivery of net zero, and to meet emerging security of electricity supply challenges resulting from increasing demand and greater volumes of intermittent renewables on the system.

In early 2022, we intend to come forward with a consultation on more developed proposals for changes to the Capacity Market in respect of the areas which fall under ‘Short-term considerations’ discussed in this Call for Evidence. These proposals will be informed by the range of responses we receive to this Call for Evidence and by further stakeholder engagement, and will also be supported by further analysis. We will look to implement any changes by prequalification in 2023. We also intend to work closely with stakeholders and come forward with proposals for consultation in due course on the future policy direction on cross-border participation.

This document initiates engagement with stakeholders on the Ten-year Review of the Capacity Market. In the coming months, we will commence our research to assess the extent to which the Capacity Market has met its objectives as part of our review – therefore initial views in this

[19] The UK-EU Withdrawal Agreement transition period (the “Transition Period”) ended at 11pm on 31 December 2020.

Call for Evidence are important to scope our work. By the end of 2021, we will have formed an external committee which will meet regularly. Through this (as well as bilateral meetings, consultations, and future calls for evidence) we will engage with stakeholders on their views of the Capacity Market, whether it remains a viable mechanism for the future, and what changes could be pursued in light of our changing system needs.

1.7 How to respond

This call for evidence will be open from 26 July 2021 until 18 October 2021. Please submit your response to this Call for Evidence by 11:59pm on 18 October 2021. A summary of responses and further information on next steps will be published shortly after the Call for Evidence closes. When responding, please state whether you are responding as an individual or representing the views of an organisation. Your response will be most useful where it is framed in direct response to the questions posed, though further comments are also welcome. Email to: energy.security@beis.gov.uk

1.8 Confidentiality and data protection

Information you provide in response to this Call for Evidence, including personal information, may be disclosed in accordance with UK legislation (the Freedom of Information Act 2000, the Data Protection Act 2018, and the Environmental Information Regulations 2004).

If you want the information that you provide to be treated as confidential, please tell us in your response, but be aware that we cannot guarantee confidentiality in all circumstances. An automatic confidentiality disclaimer generated by your IT system will not be regarded by us as a confidentiality request.

We will process your personal data in accordance with all applicable data protection laws. See our privacy policy.

2. Short Term Considerations: Early Action to Align the Capacity Market with Net Zero

2.1 Context

Our ambition to tackle climate change has increased. In June 2019, the UK became the first major economy in the world to pass laws and introduce a target to bring all greenhouse gas emissions to ‘net zero’ by 2050. Building on this commitment, in April 2021, the government set an ambitious new target in law to reduce emissions by 78% (compared to 1990 levels) by 2035, as recommended by the Climate Change Committee in Carbon Budget Six.[20] Although the government is following the Climate Change Committee’s advised budget level, this does not entail a commitment to their specific policy recommendations, and we will bring forward our own policies to meet carbon budgets. The Net Zero Strategy, to be published before COP26, will set out the government’s vision for transitioning to a net zero economy.

Extensive and rapid action across a range of sectors will be needed to achieve the government’s target, including the power sector. The key challenges to be addressed in achieving a net zero pathway for the power sector include an increased demand for electricity (for example, due to the electrification of transport), the pressing need to decrease the carbon intensity of electricity generation, and the need for more flexible and dispatchable low carbon generation, including storage and demand side response, to complement intermittent renewables (such as offshore wind) which are expected to provide the majority of electricity generation in future.

The greater ambition for decarbonising the power sector presents specific challenges for the Capacity Market. In particular, the Capacity Market will need to ensure adequate flexible and dispatchable capacity remains available as GB transitions to a net zero electricity system, older capacity closes and demand for electricity increases. Historically, high carbon capacity such as unabated gas generation has played an essential role in providing firm, dispatchable generation, and has achieved considerable success in the Capacity Market auctions (for example, in the most recent T-4 auction, unabated gas secured around two thirds of capacity agreements). However, in delivering security of supply at least cost to the consumer, the Capacity Market is also required to avoid any unintended consequences and complement the decarbonisation agenda.

To support the decarbonisation of the power sector, we will need to see significant deployment of low carbon forms of flexible and dispatchable capacity (CCUS-enabled plant, low carbon hydrogen, storage, etc.) and consider the most appropriate future role for more carbon intensive forms of generation. As set out in the Energy White Paper, the government will deploy a range of policies to encourage these alternatives to come forward.[21] Moreover, in

[20] https://www.theccc.org.uk/publication/sixth-carbon-budget/
[21] https://www.gov.uk/government/publications/energy-white-paper-powering-our-net-zero-future

order to achieve net zero by 2050 and stay within the trajectory set by our carbon budgets, the government will likely need to act to constrain in some way the role played by carbon intensive forms of generation. This could be directly, through (for example) a carbon emissions limit; indirectly, such as by limiting operational hours; and economically, through carbon pricing or through supporting sufficient low carbon, zero marginal cost flexible assets which displace gas; or a combination of these.

Until alternative forms of low carbon dispatchable generation are more widely available, we expect to continue to require carbon intensive capacity (such as unabated gas generation) on the system for operability and adequacy purposes over at least the next decade and potentially beyond (indeed, some scenario analysis suggests that retaining an amount of unabated gas generation on the system in 2050 may be consistent with net zero, provided it is running at low load factors).[22] There will also likely need to be some new build high carbon capacity, not least because over 20GW of existing capacity is expected to retire over the next ten years (including the remaining coal-fired generation and the majority of the UK's nuclear fleet, and some of the older gas-fired plants). That said, we expect that the role carbon intensive capacity plays in the system will evolve from primarily running at high load factors towards providing capacity to help guarantee security of supply at peak times. The government recognises the importance of policy stability during this transitional phase and will continue to engage closely with stakeholders and provide as much advance visibility as possible on any changes in policy.

The immediate challenge for the Capacity Market, in this rapidly evolving policy landscape, is twofold: to ensure that its design (1) enables less carbon intensive alternatives to come forward as these technologies evolve, and (2) continues to support more carbon intensive forms of capacity such as unabated gas (recognising its essential role in maintaining security of supply but also that its economics will become increasingly challenging over time) in a manner that does not act as a barrier to future action on decarbonisation.

Consideration of the implications of the net zero imperative for the Capacity Market will be a key focus of the statutory Ten-year Review (due for publication by 2024), which is introduced in Chapter Four of this document. There are also several changes we believe we need to make in the shorter-term in order to address the challenges identified above and so better align the Capacity Market with net zero. We present three important areas of change in this section: changes to agreement lengths, changes to enable low carbon projects with long build times to participate in the Capacity Market, and changes to auction design. The changes we consider for these areas are targeted at minimising future security of supply risks whilst enabling early actions to help address the need for the capacity mix of the Capacity Market to be compatible with achieving net zero targets, and to reduce or remove as far as possible any barriers to low carbon technologies participating in the Capacity Market.

Section 2.2 sets out considerations regarding the definition of 'low carbon' in the context of the Capacity Market and seeks evidence on how best to approach this question while ensuring the

[22] To note, this analysis was carried out before the government's adoption of Carbon Budget Six in 2021. https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/947439/energy-emissions-projections-2019-annex-o-net-zero-power-sector-scenarios.pdf

Capacity Market continues to meet its core objective of providing security of supply at least cost to consumers.

Section 2.3 focuses on possible changes to agreements lengths which are aimed at minimising the risks associated with long multi-year agreements whilst recognising their role in supporting investment in new capacity. We examine possible changes to the eligibility criteria for long-term agreements (including linking eligibility to an emissions limit) in order to avoid ‘locking in’ higher carbon capacity where this could create future security of supply and net zero risks, but also to support investment in sufficient firm, dispatchable generation, particularly less carbon intensive forms of capacity, to ensure security of supply. This section also explores whether adjustments to capital expenditure thresholds are needed to reflect changes in the capacity mix since the Capacity Market was first designed.

Section 2.4 focuses on options for addressing the challenges faced by low carbon technologies with long build times (such as pumped-storage hydropower) in respect of the delivery timeframes set by the T-4 auction. We examine the possibility of enabling certain new build CMUs to declare a later first delivery year as part of their prequalification application for a T-4 auction, based on their ability to evidence a need for a longer construction time.

Finally, section 2.5 explores possible changes to the design of the Capacity Market auctions which may help support investment in low carbon new build capacity. In particular, a low carbon split auction is considered as an option which could provide space for low carbon capacity to come forward whilst minimising cost risks for consumers.

In setting out these considerations about how best to align the Capacity Market’s design with the wider decarbonisation agenda, we recognise the importance of stakeholder evidence in addressing the design challenges and opportunities we face. We will provide multiple opportunities to engage both while this Call for Evidence remains open and subsequently, in order to identify detailed proposals (if any) to bring forward for consultation in early 2022. Following a full consultation process, any changes to the Capacity Market’s design will be taken forward for implementation no earlier than the prequalification period in 2023.

We also note that this Call for Evidence constitutes one of many areas of government activity aimed at supporting the decarbonisation of the power sector. In particular, we note that the Capacity Market is not the only (or necessarily the main) route through which low carbon projects may seek to come to market. For example, CCUS developments can also seek support through the Dispatchable Power Agreement (DPA) business model,[23] the deployment of hydrogen may be supported by new hydrogen business models, and low carbon technologies may instead come to market via support from the Contracts for Difference scheme. We will therefore need to consider further how the changes we explore in this Chapter could interact with other net zero policy developments and how this may evolve over time.

[23] For details of the DPA, see https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/984402/dpa-update-may-2021.pdf

2.2. Low carbon capacity

2.2.1 Context

As outlined in the Energy White Paper, we expect a low cost, net zero electricity system to be composed predominantly of wind and solar. However, to ensure security of supply, this intermittent capacity will need to be complemented by capacity which can provide power or reduce demand whenever, and for whatever duration, necessary (for example, whenever renewable generation is low). To meet our Carbon Budget Six target, the flexible and dispatchable capacity necessary to support expanding renewable deployment will increasingly need to be 'low carbon'.

In the context of the Capacity Market, we need to consider what capacity types can be defined as 'low carbon capacity', as this will have implications for some of the other potential design changes under consideration in this chapter: access to longer-term agreements; access to extended build times; and entry into a low carbon split auction.

2.2.2 Defining low carbon capacity in the Capacity Market

The definition of low carbon capacity in the Capacity Market – and what this could mean in terms of access to long term agreements and innovations such as split auctions – could have a significant impact on the types of capacity which come forward, the carbon intensity of this capacity, the costs of the Capacity Market, and ultimately, on the extent to which the CM can meet its objectives and contribute to wider objectives for the power sector.

'Low carbon capacity' could be defined with reference to a carbon emissions limit, a concept already established in the Capacity Market. A key consideration, therefore, is whether low carbon capacity is defined by reference to a zero or almost zero carbon emissions limit (to include capacity such as CCUS-enabled gas generation, 100% hydrogen-fired generation, long-duration storage, and turn-down DSR), or whether it should be defined by reference to a higher (albeit still low) emissions limit (to include hydrogen blend capacity, for example).

An important consideration when defining low carbon capacity will be the potential interactions with the other changes considered in this chapter. For example, the types of capacity which could be included in different definitions could impact clearing prices in a potential low carbon split auction and so impact on consumer costs. Furthermore, defining low carbon capacity could spur innovation with capacity providers investing in technologies defined as 'low carbon capacity' in order to access longer term agreements (section 2.3) and a split auction (section 2.5). Including hydrogen blend capacity in the definition could be an important first step in encouraging the growth of a hydrogen economy.

2.2.3 Determining the basis of the emissions limit

Consideration would also need to be given as to whether the emissions limit should be defined on the basis of a capacity's carbon intensity (kgCO2/MWh) or total annual emissions (kgCO2 per annum). It might be possible for a higher carbon unit, such as gas-fired generation, to meet a low annual emission limit if its running was limited to periods of high electricity demand or stress events. This approach could meet all three of the Capacity Market's objectives – to ensure security of electricity supply at least cost to consumers, and to avoid unintended consequences – inasmuch as firm dispatchable capacity could be provided when needed to support security of supply with lower overall emissions (thereby ensuring security of supply whilst also supporting the decarbonisation agenda), and as gas-fired generating capacity has come forward at auctions in large volumes relatively cheaply to date, the capacity it provides could be secured at a lower cost to consumers.

Summary of considerations put forward in section 2.2

- Continue to use the established approach of a carbon emissions limit to define 'low carbon' capacity in the Capacity Market.

- Key considerations include the level at which to set the carbon emissions limits and whether to base the limit on a capacity type's carbon intensity or its total annual emissions.

Questions on considerations in section 2.2

Question 1

Could 'low carbon capacity' in the context of the Capacity Market be defined in terms of an emissions limit? If so, what should form the basis of this limit – for example, would it be better to base a limit on carbon intensity or overall annual emissions, and what types of capacity should be captured by this emissions limit?

Question 2

Are there alternative approaches to defining low carbon capacity in the context of the Capacity Market? Please provide justifications.

2.3 Agreement lengths

2.3.1 Context

As stated in our Five-year Review of the Capacity Market,[24] our preference is for one-year agreement lengths wherever possible, unless there is strong evidence to deviate from this. Longer-term agreements expose the consumer to a variety of risks, such as price, competition, and volume risks. In contrast, one-year agreements minimise financial risks to the consumer and avoid the potential risks associated with 'locking-in' capacity for the long-term, such as a lack of innovation and reduced environmental performance. To date, we have therefore limited eligibility for fifteen-year and three-year capacity agreements to new build generation, unproven DSR, and refurbishing generation on the basis that high capital projects need agreements of this length to access finance and compete in the Capacity Market.

Our Five-year Review noted our commitment to re-examining the need for longer-term agreements and the scope of their eligibility, in order to ensure that they deliver value for money for consumers and do not give rise to unintended consequences. As noted in section 2.1, achieving net zero in the power sector will present new challenges for the Capacity Market in terms of its ability to ensure security of supply whilst enabling the wider decarbonisation agenda. In this context, we need to re-examine the role played by multi-year agreements in helping the Capacity Market to achieve its objectives.

This section sets out a reconsideration of the eligibility criteria for multi-year agreements. Key factors include:

- Multi-year agreements could help facilitate investment in the low carbon new build capacity needed to ensure security of supply in a net zero context.
- Multi-year agreements, particularly those with a fifteen-year duration, could lock-in carbon intensive capacity to the electricity generation mix into the 2040s and beyond and jeopardise our ability to meet the net zero target. As well as creating potential obstacles to meeting net zero targets, fifteen-year agreements could pose financial risks for high carbon CMUs, given future market conditions for this type of capacity are difficult to predict, which makes fixing a (potentially low) Capacity Market price a risky proposition. In turn, this could create future security of supply risks in the Capacity Market.
- As noted in section 2.1, to ensure security of supply is maintained as we transition towards net zero, there will still likely need to be some degree of investment in new build unabated gas until less carbon intensive forms of dispatchable generation are available at scale.

[24] https://www.gov.uk/government/publications/capacity-market-5-year-review-2014-to-2019

This section explores these challenges in more detail and seeks evidence on the most appropriate use of Capacity Market agreement lengths to avoid risks both to security of supply and to meeting net zero targets. Specifically, we are seeking evidence on:

- new eligibility criteria for multi-year agreements, including the introduction of an emissions limit for determining eligibility (i.e. limiting access to fifteen-year agreements to 'low carbon capacity'), and
- whether new build capacity which is not 'low carbon' should still have access to multi-year agreements, albeit of a shorter duration than the fifteen years currently available.

In reviewing multi-year agreements, we are also taking the opportunity to seek views on other aspects which may need to be updated, particularly capital expenditure thresholds. We are seeking evidence on the data points which determine these thresholds (which have not been updated since the Capacity Market's inception and may not be appropriate for the future capacity mix), and on whether these thresholds present a barrier to participation for certain technology types (such as DSR). Finally, we also seek views on the continued relevance of the Extended Years Criteria.

2.3.2 Eligibility for multi-year agreements

2.3.2.1 Avoiding high carbon lock-in

Access to multi-year agreements in the Capacity Market is currently tied to capital expenditure thresholds, on the basis that only projects which have the greatest difficultly in accessing finance should be eligible for long-term agreements. However, in light of the pressing need to decarbonise the power sector, capital expenditure thresholds may no longer be the only criterion which should apply in the Capacity Market to determine eligibility for multi-year agreements.

This is especially relevant for the longest agreements (up to fifteen years). Once awarded in the T-4 auctions, such agreements effectively 'lock-in' certain CMUs for almost twenty years (accounting for both the agreement length and the period between the auction and delivery year). Without action, we could see a significant volume of carbon intensive capacity – possibly up to 10-20GW of new build unabated gas in some scenarios – winning long term agreements in the capacity auctions over the next ten years.[25] Although this capacity could make a valuable contribution to security of supply at a low cost to consumers, it may also have a detrimental impact on achieving the Capacity Market's parallel objective of complementing the wider decarbonisation agenda.

One possible response to this problem could be to remove multi-year agreements from the Capacity Market's design and only offer one-year agreements. However, some new build and refurbishing capacity may continue to require the 'bankable' and secure revenue stream that long-term agreements provide in order to come forward. Moreover, as we progress towards net

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[25] Based on known policies from 2019 and illustrative Net Zero scenarios from the 2019 Energy and Emissions Projections, Annexes H and O
https://www.gov.uk/government/publications/updated-energy-and-emissions-projections-2019

zero, the technologies which have the potential to contribute to security of supply are expected to change. For example, the future capacity mix is likely to include an increased amount of low carbon technology such as CCUS, hydrogen and large-scale storage. Long multi-year agreements may contribute to supporting the investment case for such capacity, particularly where more innovative new build technologies are concerned.[26]

To ensure the Capacity Market does not create barriers to meeting net zero targets by locking in carbon intensive capacity for long periods, we may need to limit eligibility for multi-year agreements available in the Capacity Market to low carbon types of capacity. As outlined in section 2.2, we will need to consider carefully how to define low carbon capacity. One possible approach could be to link eligibility for multi-year agreements to a CO2 emissions limit. The Capacity Market already includes a CO2 emissions limit which applies to all new CMUs.[27] The limit is set at 550gCO2/kWh, which effectively excludes certain types of generation (most notably unabated coal fired generation) from participating in the Capacity Market. However, this does not prevent other carbon intensive technologies (such as unabated gas-fired generation) from competing in the Capacity Market and therefore from accessing multi-year agreements of up to fifteen years under the current system.

We could therefore link eligibility for multi-year agreements to a new lower emissions limit. For the longest multi-year agreements available in the Capacity Market (up to fifteen years), we may wish to set an emissions limit which ensures that only very low or zero carbon types of capacity would be eligible. As discussed in section 2.2 concerning the definition of 'low carbon' capacity, this might include capacity such as renewables, storage, low carbon DSR, CCUS-enabled generation, and hydrogen fired generation.

However, in exploring the above approach we would also need to account for technologies which may initially be considered as 'lower' rather than 'low' carbon. Early hydrogen projects – which are likely to use a blend of low carbon H2 with natural gas – are a good example of generation which would not meet the same emissions limit as the capacity types listed above but could be expected to become low carbon in the future with the implementation of 100% hydrogen firing turbines.

In view of the potential of such technologies to become low carbon and the reduced risk of carbon intensive lock-in, we could take a more flexible approach to determining eligibility for multi-year agreements for 'lower' carbon capacity. For example, we could set an emissions limit at a level which would allow lower carbon capacity to access agreements of up to fifteen years. However, although we might expect developers of lower carbon capacity to opt for an agreement length somewhat shorter than the full fifteen-years so they can rebid into the Capacity Market and seek a new agreement to help finance conversion to being low carbon at

[26] We note that the CM is unlikely to be the main route to market for such technologies, at least initially, as the government is bringing forward a range of support mechanisms, such as the Dispatchable Power Agreement (DPA) model for CCUS plant. However, we would expect to see participation in the CM increase over time, as has been the case with onshore wind and solar. See https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/984402/dpa-update-may-2021.pdf

[27] i.e. Generating Units with a Commercial Production Start Date on or after 4 July 2019.

an appropriate point, the attraction of a full fifteen-year agreement could also encourage developers to slow or postpone their decarbonisation plans.

Another approach could be to introduce additional controls regarding eligibility for multi-year agreements for lower carbon capacity. For example, we could offer shorter multi-year agreements (e.g. between five and ten years) for capacity types which do not meet the emissions limit but have high potential to become fully low carbon.

Given the complexities involved, should we wish to pursue the approach of linking eligibility for multi-year agreements to an emissions limit, we would need to carry out a technical study to determine the level at which the emissions limit should be set to best reflect our policy objectives.

2.3.2.2 Multi-year agreements and security of supply

If eligibility for multi-year agreements does become linked to a new lower emissions limit, this could create a scenario in which higher carbon capacity (such as unabated fossil-fuel generation, high carbon forms of DSR, and waste to energy plant) would only be eligible for one-year agreements. However, we would need to balance the benefits of this scenario (supporting decarbonisation) with the risks it could present from a security of supply perspective.

As noted in section 2.1, it is likely that we will need some continued investment in new build higher carbon capacity (such as unabated gas) over the coming decade to ensure security of supply in the face of plant closures and increasing demand, until such a point that low carbon alternatives (such as low carbon hydrogen or CCUS-enabled generation) can be widely deployed to provide dispatchable generation to complement intermittent renewables. We therefore need to explore appropriate agreement lengths for supporting investment in more carbon intensive forms of capacity without risking our net zero target or security of supply.

The security of supply risks linked to agreement lengths for new build higher carbon capacity are two-fold. Firstly, there is a risk that one-year agreements could fail to provide sufficient incentive for investment in new plant. However, from responses to the Five-year Review and subsequent discussions with stakeholders, we recognise that that the power sector and investment landscape has shifted significantly since the Capacity Market was introduced, such that long multi-year agreements may no longer be necessary to support investment in new build high carbon capacity in all circumstances. For example, small scale gas generation is unlikely to require fifteen-year agreements to access finance, while some large CCGTs have taken their final investment decision ahead of securing a capacity agreement. This suggests that higher carbon capacity may continue to come forward with only one-year Capacity Market agreements.

Secondly, long multi-year agreements of up to fifteen years could create financial risks for unabated gas CMUs, given the inherent difficulties in predicting the market for more carbon intensive forms of generation into the 2030s. As noted in section 2.1, the decarbonisation of the power sector will likely involve higher carbon capacity transitioning from running at midmerit load factors to running primarily at peak times, and the government will engage in due course on the most appropriate policy levers to support this transition. It could therefore be the case that at a future point during a long multi-year agreement, higher carbon CMUs may wish to rebid into the Capacity Market to secure a price which reflects their changed costs and revenue flows, or to support investment in emissions abatement (for example, conversion to hydrogen firing or fitting CCUS technology) but would be unable to do so. This could in turn create future security of supply risks, particularly if a substantial number of CMUs were to terminate their Capacity Market agreements unexpectedly.

To address these security of supply risks and ensure our approach is consistent with the delivery of net zero targets, we believe it may be necessary to allow carbon intensive generation (such as unabated gas generation) to access multi-year year agreements, albeit of a shorter duration. Agreements of up to five years (for example) could help to support the investment in the volume of new build high carbon capacity required for security of supply as we transition to net zero. Further consideration and engagement with stakeholders will be needed to identify what length of agreement appropriately balances support for investment, impacts on consumer costs, and risks of high carbon capacity lock-in. Consideration will also be needed as to how long this arrangement should be maintained, given that we expect low carbon dispatchable generation to become more widely available at scale as the decade progresses.

We also intend to explore how this approach could be supported by the government's proposed update to Carbon Capture Readiness requirements in our recent Decarbonisation Readiness Call for Evidence, which sets out options for ensuring that any plants built unabated have demonstrated a viable route for decarbonising during their lifetime.[28] Indeed, we could consider linking eligibility for shorter multi-year agreements for carbon intensive capacity directly to the requirement to have such a plan in place. In this respect, we will also need to explore further the most suitable approach to agreement lengths for plants which are currently unabated but may subsequently seek to refurbish in order to decarbonise, as well as how to ensure that existing long-term Capacity Market agreements do not act as a barrier to the timely decarbonisation of unabated gas CMUs.

An alternative approach, which could allow unabated gas CMUs to continue to access the longest multi-year agreements, would be for such plant to restrict running hours in order to comply with an annual cap on annual emissions. An annual emissions limit already exists in the Capacity Market and could be extended to act as a 'condition precedent' for unabated peaking plants to access multi-year agreements. As noted in section 2.1, peaking plant could be important for security of supply and may not make significant contributions to overall carbon emissions, even if they are unabated.

[28] https://www.gov.uk/government/consultations/decarbonisation-readiness-call-for-evidence-on-the-expansion-of-the-2009-carbon-capture-readiness-requirements

2.3.3 Other aspects of agreement lengths

2.3.3.1 Capital expenditure thresholds

As noted in section 2.3.2.1, access to three- and fifteen-year agreements in the Capacity Market is currently tied to capital expenditure thresholds. The rationale for this was that projects with a high level of capital expenditure would experience difficulty in accessing finance, and so would likely be uncompetitive in the auctions without access to multi-year agreements and the associated benefit of a long-term, reliable, and 'bankable' revenue stream.

The thresholds were set in 2013 at £250/kW for a fifteen-year agreement and £125/kW for a three-year agreement. These thresholds have been linked to inflation and so are now £280/kW and £140/kW respectively. The evidence used to determine these thresholds was as follows:

- Fifteen-year agreement: the new build costs of an OCGT.
- Three-year agreement: the costs of fitting selective catalytic reduction (a NOx abatement technique) to a coal plant.

Our approach to capital expenditure thresholds has not been substantially revised since the Capacity Market's inception. Given that the context in which the Capacity Market operates has evolved and will continue to change, it is appropriate that we should review the capital expenditure thresholds as part of our wider re-examination of agreement lengths.

Initially, we may wish to revisit the rationale for linking multi-year agreements with capital expenditure. At present, this link is based on the assumption that multi-year agreements are justified due to the financing needs of projects with high capital expenditure. However, we recognise that the investment context for the Capacity Market and the technology mix capable of providing security of supply is changing, and we are therefore seeking views on whether this remains appropriate, and whether there are alternative approaches we could take.

If we are to continue linking eligibility for multi-year agreements to capital expenditure thresholds, we must also consider the evidence base used to determine these thresholds. Given the changes in the types of capacity now competing in the Capacity Market, we acknowledge that the evidence used to determine access to fifteen- and three-year agreements may no longer provide the most suitable data points. Hence, we are seeking views on which data points may be more appropriate – for example, the thresholds could instead be linked to the costs of decarbonising (such as the retrofitting of CCUS technology or conversion to hydrogen firing). We also note that tying eligibility for three-year agreements to refurbishment costs may no longer be logical, given that refurbishing CMUs can currently access agreements of up to fifteen years, and that we have recently consulted on aligning the long-stop date for refurbishing CMUs with new build CMUs.

Furthermore, we need to consider whether capital expenditure thresholds are acting as a barrier to accessing multi-year agreements for some types of capacity. For example, DSR has been eligible for multi-year agreements since 2020, based on the same capital expenditure thresholds which apply to generating CMUs. Although stakeholders welcomed this change because of its potential to support business cases and the recruitment of component customers, many noted that it was not appropriate to base access to multi-year agreements for DSR on capital expenditure, given that DSR is not in general a high-capital expenditure technology.

To address this challenge, we could consider DSR CMUs to be eligible for multi-year agreements where they achieve the new lower emissions limit discussed in section 2.3.2.1 but would not be able to meet similar capital expenditure thresholds to other low carbon new build. In this way, we could enable turn-down or other low carbon DSR to access multi-year agreements of an appropriate length (for example, up to three years) without meeting the same capital expenditure thresholds as other low carbon new build capacity. The longer-term revenue stream could help to support the expansion of low carbon DSR, thereby complementing the broader decarbonisation agenda in line with the Capacity Market's objectives.

Finally, we are also considering changes to the Capacity Market Rules relating to the timeframe for capital expenditure for new build CMUs. Under the current Rules, the capital expenditure for new build CMUs must be spent within a 77 month window in order to count towards the capital expenditure thresholds. This window was defined to ensure that new build CMUs in the first round of Capacity Market auctions could capture their full CAPEX costs, and we now need to consider whether this window should be refined to ensure that it remains appropriate. For example, one option could be to harmonise the window for new builds with the window for refurbishing plant (in other words, from auction results day until the start of the first delivery year).

2.3.3.2 Extended Years Criteria

Prospective Generating CMUs with agreements of four to fifteen years must meet the Extended Years Criteria.[29] The purpose of the Extended Years Criteria is to provide assurance that Prospective Generating CMUs with agreements of four or more years contain equipment which is new (or 'as new' where rebuilt assets are concerned) and built to a high standard, and therefore likely to last for the full term of the agreement.

However, we intend to reconsider whether it remains necessary to maintain Extended Years Criteria in the Capacity Market. For example, in the Future Improvements consultation,[30] we allowed unproven DSR to access the same multi-year agreements as generating CMUs, but we were unable implement the Extended Years Criteria for DSR because DSR components may be reallocated after an agreement has been awarded. Moreover, there are already strong incentives in the Capacity Market for CMUs to maintain their capacity obligations throughout multi-year agreements. For example, all CMUs must meet three satisfactory performance days (SPDs) during each delivery year, in which they must demonstrate that their capacity obligation is available. Failure of SPDs can ultimately result in the termination of a capacity agreement

[29] The Extended Years Criteria are defined in Rules 8.3.6B and 8.3.6C.
[30] https://www.gov.uk/government/consultations/capacity-market-proposals-for-future-improvements

and the imposition of substantial termination fees. CMUs are also able to reduce or increase their capacity obligation via secondary trading.

Due to these factors, and given that the current approach may be burdensome and costly both for operators and the Delivery Body, we are seeking views on whether to continue to implement the Extended Years Criteria in the Capacity Market. However, we also recognise that the Extended Years Criteria address not only the operational status of a CMU but also provide confirmation that a CMU meets its associated combustion installation and efficiency standards. If the Extended Years Criteria are removed from the Capacity Market, we would need to consider alternative ways of ensuring that these standards are met.

Summary of considerations put forward in section 2.3

- Consider limiting access to the longest multi-year agreements available in the Capacity Market (up to fifteen years) to ‘low carbon’ capacity.

- Consider further how to account for ‘lower’ rather than ‘low’ carbon capacity when determining eligibility for multi-year agreements.

- Carry out a technical study to determine the level at which the emissions limits should be set in order to best reflect our policy objectives.

- Consider offering high carbon forms of capacity one-year agreements wherever possible.

- Consider continuing to provide access to shorter multi-year agreements for higher carbon capacity where this is necessary to ensure security of supply.

- Consider linking access to multi-year agreements for high carbon capacity to additional criteria, such as compliance with Decarbonisation Readiness requirements or the restriction of running hours to comply with a cap on annual emissions.

- Reassess the rationale for linking multi-year agreements with capital expenditure and consider whether this link should be maintained.

- Reassess the evidence base underpinning the capital expenditure thresholds and consider alternative data points which could be used to determine access to multi-year agreements.

- Consider allowing capacity such as ‘low carbon’ DSR to access multi-year agreements where it complies with the new lower emissions limit (considered in section 2.3.2.1) without meeting the same capital expenditure thresholds as other low carbon new build capacity.

- Review the 77 month window for capital expenditure thresholds for new build CMUs.

- Consider the benefits of maintaining the Extended Years Criteria.

Questions on considerations in section 2.3

Question 3

What are your views on the benefits or challenges of linking future long-term Capacity Market agreements to a new carbon emissions limit? Do you have any suggestions regarding an appropriate approach to setting such an emissions limit, and how could we best account for 'lower' rather than 'low' carbon technologies in determining eligibility for multi-year agreements?

Question 4

Is it necessary and appropriate for carbon intensive generation to continue to access shorter multi-year agreements, until such a time as low carbon dispatchable generation is more widely available?

Question 5

Would you expect these suggested changes to agreement lengths to affect your decision to participate in the Capacity Market, your bidding behaviour, or the costs of and access to finance? If so, how? Can you suggest any alternative approaches to ensuring agreement lengths offered in the Capacity Market are consistent with the delivery of net zero targets?

Question 6

Is it still appropriate to maintain the link between capital expenditure thresholds and multi-year agreements? If not, what other criteria could we consider using to assess eligibility for multi-year agreements (other than the new lower emissions limit discussed in section 2.3.2.1)?

Question 7

Should we revise the applicable capital expenditure thresholds? If so, what data could we base them on, and do we still need to have two different thresholds? Should low carbon DSR be able to access shorter multi-year agreements on the basis of emissions limits rather than capital expenditure thresholds?

Question 8

Should we review the 77 month window for new builds?

Question 9

What are the benefits of maintaining the Extended Years criteria?

2.4 Removing barriers to the participation of technologies and projects with long build times

2.4.1 Context

In July 2020, the government announced that it will amend planning legislation to remove barriers to market entry for energy storage projects.[31] This is part of the government's commitment to supporting the deployment of electricity storage and enabling the full value of renewables to be captured even when generation is high, but demand is low. In line with this commitment, we intend to review the Capacity Market to ensure that technologies such as new build Pumped Storage Hydropower (PSH), which have long build times, can continue to compete in the market on a fair and level basis with no unintended barriers to entry.

The Five-year Review identified that PSH, and potentially some other types of new build CMU, have longer build times than those provided for under the current Capacity Market framework. New build CMUs that successfully secure capacity agreements in a T-4 auction are currently incentivised to deliver from the start of their given delivery year (approximately four years from securing an agreement to delivery). If they are unable to do so, however, they have some flexibility to meet the Substantial Completion Milestone or Minimum Completion Requirement (MCR)[32] (the 'relevant completion requirement') up to 12 months after the start of the first delivery year (Long-Stop Date).[33] New build CMUs are not, however, eligible for payments nor exposed to penalties until the capacity agreement has taken effect.[34] This incentivises capacity to deliver by the start of the delivery year as late delivery could introduce risks to security of supply.

The current Capacity Market framework therefore effectively provides capacity providers with up to approximately five years to deliver a New Build CMU, albeit with a reduction in the total agreement length and the forfeit of up to 12 months of Capacity Market revenues. We recognise that some large infrastructure projects may need more time than five years, and that utilising the flexibility of the Long-Stop Date is sub-optimal as it erodes the value of the agreement.

We are seeking views through this Call for Evidence on how these challenges could be addressed and, in so doing, remove uncertainty to structuring of finance for projects with long build times. In particular, we are considering proposals in respect of new build and refurbishing CMUs, such as PSH, that need a longer delivery timeframe than the five years provided for in the Capacity Market, and whether they should be provided with more time for construction and an avenue to maintain their full agreement term.

[31] Battery storage boost to power greener electricity grid: https://www.gov.uk/government/news/battery-storage-boost-to-power-greener-electricity-grid. Upgrading our energy system: smart systems and flexibility plan: https://www.gov.uk/government/publications/upgrading-our-energy-system-smart-systems-and-flexibility-plan
[32] See Rule 6.8.5.
[33] See Rule 1.2.1 for the definition of the Long-Stop Date.
[34] See Rule 6.7.1 and Rule 6.8.2.

2.4.2 New Build CMUs declaring a later first delivery year

2.4.2.1 Introducing a declared later delivery year

We are considering whether new build Generating CMUs, that suitably evidence that they need more time for construction than the start of the delivery year of the T-4 auction, should be afforded the ability to declare in their prequalification application for a T-4 auction a later first delivery year (a ‘declared later delivery year’).

We are considering whether the declared later delivery year could be up to the delivery year which commences two delivery years after the delivery year for the T-4 auction in question (effectively turning the T-4 auction into a T-6 auction for those CMUs). A declared later delivery year could also commence one delivery year after the delivery year for the T-4 auction in question (i.e. T-5). We do not believe it would be appropriate to allow CMUs to opt for a later delivery year in T-1 auctions.

We anticipate that very few new build CMUs would seek to take advantage of this proposal as it would be limited to those technologies and projects that can sufficiently evidence that there are no examples of comparable projects coming to market in four years. For example, CMUs of a technology type that has long standing evidence of the ability to deliver capacity within the timeframes allowed within the current Capacity Market framework would not be able to apply for a later delivery year.

We are mindful that this proposal has the potential to introduce security of supply risks if large volumes of new build CMUs opt for a later delivery year, particularly if they do so when it is not strictly necessary (e.g. to mitigate the risks and impacts of late delivery, an OCGT developer may wish to apply for a later delivery year and enter T-1 auctions for earlier delivery years if it delivers on schedule). We are, therefore, considering options for minimising potential security of supply risks associated with this proposal, including:

- Considering how the volume of capacity with a ‘declared later delivery year’ can be covered between the T-4 delivery year and the later delivery year. It may be the case that we only allow a later delivery year to be obtained in the low carbon split auction (section 2.5) which could take place prior to the main Capacity Market auction. Any capacity that is awarded a later delivery year in the earlier split auction would then be added to the target capacity of the later main auction to ensure sufficient capacity is secured for the T-4 delivery year.
- A new requirement to submit a declaration at prequalification stage, signed by a director, and accompanied by supporting evidence that construction of the project is not possible by the T-4 delivery year (outlined below in section 2.4.2.2). We suggest that this declaration and supporting evidence should be verified by an Independent Technical Expert (ITE).[35]
- Rules preventing CMUs with a declared later delivery year from prequalifying for T-1 auctions for delivery years that predate the declared later delivery year. In this spirit, we

[35] See definition of Independent Technical Expert in Rule 1.2.1.

think it will be necessary to prevent any CMU taking advantage of these proposals from becoming a Secondary Trading Entrant prior to the commencement of the declared later delivery year. This means it will not be possible for these CMUs to obtain Capacity Market revenues prior to the commencement of the declared later delivery year or until meeting the relevant completion requirement, whichever is the later.

- Refinements to the Capacity Market Rules so that in the event of early delivery (i) the agreement would still only take effect (and capacity payments commence) at the start of the declared later delivery year, and (ii) if a CMU falsely declared that it needed longer than the four years to come to market, and early delivery could not be justified, it could ultimately result in termination. We are considering whether a new termination event would be necessary or if the termination event in Rule 6.10.1(o) is appropriate,[36] as well as considering Ofgem's role in an investigation as part of a false declaration at prequalification.

We believe that CMUs with a declared later delivery year should also benefit from the existing arrangements relating to the Long-Stop Date (i.e. so these CMUs will have up to 12 months following the start of the declared later delivery year). This effectively provides a maximum of up to seven years to deliver capacity in the event a CMU has a declared later delivery year of two delivery years after the start of the T-4 delivery year.

The government is separately considering whether new build PSH should be able to benefit from cap and floor arrangements.[37] If this is the case, then we might introduce Rules to ensure new build PSH projects in receipt of cap and floor benefits will only be allowed access to one-year agreements, as is already the case for interconnectors.

2.4.2.2 Qualifying for a declared later delivery year

We believe that CMUs wishing to qualify for a declared later delivery year should be required to provide suitable supporting evidence which identifies why it is not possible to construct and deliver the new build CMU within the standard four-year lead in time, verified by an Independent Technical Expert. This evidence will need to reference the delivery timeframes for other comparable projects. Our expectation is that the requirements will need to be robust – for example, the evidence provided may need to take the form of an evidenced project timeline with key development and build milestones, as a minimum, as part of a construction plan.

2.4.2.3 Other requirements in respect of CMUs prequalified for a declared later delivery year

We think it would be appropriate to maintain some other aspects of the current Rules which we consider are fit for purpose in respect of this proposal. For example, if a CMU were to declare that it would be available at the start of a declared later delivery year, but was then delayed

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[36] Rule 6.10.1(o) establishes a termination event if any information or declaration submitted in or with a prequalification application does not satisfy Rule 3.12.1. No termination fee is currently payable in respect of the termination event established by Rule 6.10.1(o).

[37] https://www.gov.uk/government/consultations/facilitating-the-deployment-of-large-scale-and-long-duration-electricity-storage-call-for-evidence

and so required the Long-Stop Date provision, it will still lose the corresponding time off its agreement length (i.e. a maximum of 12 months) and not receive any capacity payments until the one of the relevant completion requirements. Furthermore, it will not be able to request a later delivery year after prequalification has concluded.

Similarly, we believe the existing requirement for a remedial plan, when it becomes apparent from a progress report that a Prospective CMU will achieve its Substantial Completion Milestone after the first day of a relevant delivery year, should apply to CMUs with a declared later delivery year.

Summary of considerations put forward in section 2.4

- Consider allowing New Build Generating CMUs to declare at prequalification stage a later first delivery year (a 'declared later delivery year'), up to and including the delivery year which commences two delivery years after the delivery year for the relevant T-4 auction.

- Base eligibility for a declared later delivery year on suitable criteria (e.g. that there are no examples of comparable projects coming to market in four years) and establish appropriate arrangements for verifying eligibility (e.g. requiring verification of supporting evidence by an Independent Technical Expert).

- Ensure that this approach does not impact on security of supply.

Questions on considerations in section 2.4

Question 10

What are your views on the introduction of a declared later delivery year as a way of addressing the challenges experienced by projects with long build times seeking to enter the Capacity Market? Would this affect your decision to participate in the Capacity Market, and if so, how? Are there other approaches we could take to removing barriers to participation for technologies and projects with long build times?

Question 11

Do you agree with our suggested approach to determining and verifying eligibility for a declared later delivery year? Are there other approaches we could consider?

Question 12

How can we best mitigate any security of supply risks arising from this approach? Can you identify any additional risks and/or disbenefits related to the introduction of a declared later delivery year?

2.5 Alternative Auction Designs

2.5.1 Context

Since its inception, the Capacity Market has operated the same auction design of a single auction for all eligible capacity types in a descending clock format and ‘pay as clear’, where all successful participants receive the clearing price set by the marginal bidder. To date, this design has delivered security of supply at low costs to consumers, with liquid and competitive auctions. However, it has also brought forward predominantly higher-carbon technologies, particularly natural gas-fired generation. Whilst this new build unabated gas-fired generation has historically delivered on the Capacity Market’s objective of ensuring security of supply at least cost to the consumer, if this trend continues unchanged it will not necessarily put the power sector on the most cost-efficient pathway to net zero in the longer term.

The need to bring forward low carbon capacity to support our net zero ambitions and meet the anticipated increase in electricity demand means there is a strong case for re-evaluating the current auction design. Without changes, it is likely that a significant proportion of the demand for new build capacity could be met by new gas-fired generation as, generally speaking, this remains the most cost-competitive new build technology. There could also be higher clearing prices than we have historically seen in the Capacity Market, as bidders look for higher prices in anticipation of tougher ‘net zero’ consistent market conditions, with knock-on impacts for consumer costs.

We are therefore seeking feedback on the possible introduction of a new auction design, which could involve splitting the main T-4 auction between a dedicated auction for low carbon capacity (new build and refurbishing) and a larger auction for all other capacity. We believe such an approach may enable the Capacity Market both to bring forward the low carbon capacity needed to ensure security of supply in a net zero context, and to ultimately keep auction costs low in line with our central objective of delivering security of supply at least cost to consumers.

At present, holding one main T-4 auction in which all capacity types compete has kept overall auction costs low due to the low clearing prices of unabated gas-fired generation, which (as noted above) has been very successful in capacity auctions. However, the environmental cost of these auctions in terms of the carbon emissions of the capacity they bring forward also needs to be taken into account as we transition towards net zero. By contrast, new build low carbon capacity could significantly reduce the environmental costs of capacity auctions but could require higher clearing prices at auction in the short- to medium-term (for example, due to higher capital expenditure costs). However, in the longer term, new build low carbon capacity may in fact prove more cost effective than the more carbon intensive capacity which is currently helping to keep auction costs low. This is because low carbon capacity will not require further investment to decarbonise, whereas carbon intensive capacity is likely to result in higher costs in future auctions as it seeks investment to decarbonise.

A split T-4 auction involving a dedicated auction for low carbon capacity could provide space for this capacity to come forward, whilst minimising the risk of higher Capacity Market costs to consumers – both in the short term, because the higher clearing prices which may be required by low carbon new build would not increase the costs of less expensive capacity in the main T-4 auction, and in the longer term by bringing forward a strong pipeline of low carbon capacity which would not incur high costs in the future by needing investment to decarbonise.

As discussed in Section 2.2, we are seeking views as to the definition of low carbon capacity, and our preference is that a split auction would be open only to technologies defined as low carbon. However, a dedicated low carbon auction might also benefit from including capacity which is refurbishing to reduce its carbon emissions (for example, a gas-fired plant converting to firing low carbon hydrogen or installing carbon capture technology), or which already has low carbon emissions and is refurbishing to extend its operational life. The inclusion of refurbishing capacity in a low carbon auction could support the decarbonisation of existing capacity, which could be cheaper in the longer-term than replacing with new build. Furthermore, the inclusion of refurbishing capacity could also support the government's recent Call for Evidence on Decarbonisation Readiness, which seeks views on potentially expanding the current Carbon Capture Readiness[38] requirements so all combustion power plants should have demonstrated a viable route to decarbonise either through retrofitting carbon capture or hydrogen generation technologies.[39]

When considering this change to auction design, we also believe that only the T-4 auction, where the majority of capacity (including the majority of new build capacity) is procured, should be split to introduce a separate low carbon auction. The creation of a split T-1 auction would have limited benefits in supporting new build or refurbishing capacity to come forward and could detract from its role as a top-up auction.

We recognise that the introduction of split auctions could introduce risks and so requires careful consideration. For example, it could reduce liquidity, potentially increasing the market power of a single participant, as well as increasing the administrative costs of running the Capacity Market. We are therefore seeking views on the relative merits and challenges of introducing split auctions in the future, with two possible auction designs outlined below. Depending on the feedback received as part of this Call for Evidence, we may bring forward proposals for consultation.

2.5.2 Multiple Auctions

2.5.2.1 Multiple auctions design approach

A split auction with one auction for new build and refurbishing low carbon capacity and another for all other types of capacity could enable greater volumes of new build low carbon capacity to be brought forward at a lower overall cost to consumers. In this model, the government, with support from NGESO, would determine the targets for the two auctions. The auction for new

[38] https://www.gov.uk/government/publications/carbon-capture-readiness-ccr-a-guide-on-consent-applications
[39] https://www.gov.uk/government/consultations/decarbonisation-readiness-call-for-evidence-on-the-expansion-of-the-2009-carbon-capture-readiness-requirements

build and refurbishing low carbon capacity would likely have a small target capacity (potentially increasing over time), whereas the auction open to all types of capacity would secure the bulk of the capacity. This model of two separate auctions could minimise the risk of increasing overall Capacity Market costs, because the cost of the main auction open to all types of capacity would not be raised as a result of the potentially higher clearing prices of the smaller low carbon auction.

We therefore welcome views on splitting the T-4 auction with a separate smaller auction for new build and refurbishing low carbon capacity.

2.5.2.2 Multiple auctions design considerations

There would, however, be potential risks to splitting the auctions in this manner. Any change to the established Capacity Market auction design reduces certainty for participants and so they may price this uncertainty into their bids. A model which involves holding a separate smaller auction for new build and refurbishing low carbon capacity could reduce liquidity and competition in the auctions and increase opportunities for market manipulation. Whilst we anticipate that a significant amount of new build capacity will be required in the coming decade, the demand will likely be spread over a number of years, meaning each annual auction for new build low carbon capacity could be fairly small. A small auction could increase an individual participant's market power and create an incentive for participants to bid high, thus potentially increasing the cost of the auction.

A central consideration would be the challenge of accurately determining the target capacity for each auction, as this would require additional assessments to be made about the mix between the amount of existing and high carbon new build capacity required and the amount of low carbon new build available to participate in the auction. This could potentially lead to an inefficient allocation of capacity if the assessed split differs from what the market would have provided through a single auction. If we were to adopt a split auction which separated out low carbon capacity, this could be less of a concern as the auction would be fulfilling an additional function in bringing forward capacity to support our net zero commitment.

Furthermore, we recognise the challenges in determining the parameters for a low carbon auction (e.g. target, price cap, net CONE). We would anticipate the size of the low carbon target could increase over time as low carbon technologies, such as CCUS-enabled generation and hydrogen-fired generation, become more widely deployable in the late 2020s or early 2030s.

To further improve liquidity in the main T-4 auction, we could enable new build and refurbishing low carbon capacity to prequalify for both the low carbon auction and main T-4 auction. By running the low carbon auction first, unsuccessful low carbon capacity would be able to enter the main T-4 auction, thereby increasing liquidity and encouraging competition.

Whilst we would anticipate a new build and refurbishing low carbon split auction could have a higher clearing price than the main auction (to reflect the higher prices required to cover investment and capital expenditure costs) this is not certain – it would strongly depend on how and where the target for a low carbon split auction was set. There could be significant competition in a low carbon auction, potentially creating a lower clearing price.

2.5.3 Multiple clearing prices in a single auction

A single auction with multiple clearing prices for different types of capacity (i.e. new build vs. existing, or low carbon vs. higher carbon) could support bringing forward low carbon capacity and/or reduce overall auction costs when a high proportion of new build low carbon capacity is required. Additionally, holding a single auction would avoid the risks associated with determining the amount to target through two separate auctions as outlined in Section 2.5.2.2 and could result in greater competition and cheaper auction outcomes.

This type of design would still risk inefficiencies in the auction process. For example, If the auction was set with different clearing prices for new build and refurbishing low carbon capacity and existing capacity, bidders for each type would still be competing to clear the auction but would no longer be competing on price as they do in the current Capacity Market design. Existing plants may make inefficient investment decisions such as closing plants early due to the lower clearing prices for existing capacity. This would lead to increased capital spending on new build capacity without increasing the amount of capacity available overall and would increase the costs to consumers. Alternatively, existing capacity may try to anticipate the bidding behaviour of new build capacity and bid just below that anticipated figure to increase their potential clearing price above their required price. This could lead to inefficient outcomes or an increased risk of market manipulation.

Similar to the risks inherent in the multiple auction design, the smaller number of competitors in each clearing price group relative to a single clearing price auction means there is greater risk of market manipulation. Participants could be incentivised to bid above their minimum viable price if there is less competition and so increase the overall auction cost. Additionally, participants are more likely to be able to influence their own clearing price because with smaller number of participants there is a greater chance of one individual submitting the marginal bid. This could again increase auction costs. It might be possible to mitigate this risk to some degree if existing plant were unable to enter a bid above the Price Taker threshold (currently set at £25/kW/year), although we note that existing capacity can apply to be Price Makers through a memorandum to the Delivery Body.

A final consideration for a design with multiple clearing prices within a single auction would be whether it would be necessary to amend the auction format to require participants to submit an exit bid for each round, as the current descending clock design would not reveal the first rejected bid for existing plant (assuming a new build plant sets the clearing price). However, this could potentially affect bidding behaviour, as participants may enter an exit bid at the price floor for each auction round, thereby undermining the benefits of the alternative auction design.

2.5.4 Price Taker Threshold

The Price Taker Threshold is defined in Regulation 2 of the Principal Regulations as the maximum price at which a Price Taker can withdraw from a Capacity Auction, whilst a Price

Taker is a defined as a prequalified CMU not registered as a Price Maker on the Capacity Market Register. Price Takers are generally assigned to existing capacity and the Price Taker Threshold aims to mitigate market power where existing plants seek a high price, for example where new build capacity does not exert as much competitive pressure on the auction.

Government is concerned that the expected need for additional new build capacity over the coming decade (both to meet the anticipated increased demand for electricity as more of the economy electrifies, and to replace retiring capacity) will mean clearing prices in the Capacity Market will rise, increasing costs to consumers. The higher prices generally required by new build capacity to recover investment or capital expenditure costs would drive up the clearing price for all capacity, including existing capacity which generally requires a lower minimum price.

At present the Price Taker Threshold prevents price taker designated capacity from exiting the auction at a price above the threshold, but it does not prevent Price Taker capacity from receiving a higher clearing price if the auction clears above the threshold. This could result in capacity receiving a far higher clearing price than their minimum required price, and in turn passing these higher costs onto consumers. Whilst no T-4 auction to date has cleared above the Price Taker Threshold, the anticipated increased demand for capacity in the coming years means this outcome is more likely.

We are therefore seeking views on the merits of expanding the scope of the Price Taker Threshold so that it could act as a price cap to Price Taker capacity. In this model, if a Capacity Auction were to clear above the Price Taker Threshold, capacity designated as Price Takers would receive the threshold price. If the auction cleared under the threshold, Price Taker capacity would receive the clearing price.

This approach could complement a split auction whereby low carbon capacity could compete in a separate auction, or with an alternative clearing price, and a price cap only applied at the Price Taker Threshold to existing capacity in the primary T-4 auction. This could support the government’s objectives of providing security of supply at minimum cost to consumers, whilst supporting low carbon capacity to come forward.

We note that currently Price Takers can submit a Price Maker Memorandum to Ofgem and a declaration to the Delivery Body to enable them to become Price Makers.[40] If the proposals above were implemented, changes would likely be necessary to the Price Maker Memorandum to ensure the proposed new price cap would be effective. This could mean strengthening the requirements necessary for a Price Taker to become a Price Maker. We welcome feedback on how the Price Maker Threshold could be modified to support the proposed expansion above.

2.5.5 Net Welfare Algorithm and clearing rounds

The 2021/22 T-1 Auction held on 2 March 2021 returned a clearing price of £45/kW. This price did not come from an exit bid but was the clearing round price floor. The Net Welfare Algorithm

[40] See CM Rule 4.8

considers the difference between the marginal bid and the penultimate highest exit bid under the demand curve. If there is not a next highest exit bid within that round range, the Net Welfare Algorithm uses the clearing round floor as happened in this year's T-1 auction. Had the Net Welfare Algorithm used the penultimate highest exit bid, the cost of the auction could have been significantly reduced.

We are, therefore, considering whether there could be a benefit in requiring all participants to submit an exit price and to remove the element of the Net Welfare Algorithm which relies upon the clearing round floor rather than the penultimate highest exit bid. Under the current design, participants know the minimum exit bid for each round is the round floor price. However, if the Net Welfare Algorithm operated down to the penultimate highest bidder regardless of the round, participants would have much greater uncertainty as they would lose the protection of the round floor price. This could have an effect on bidding behaviour in the auction which could undermine any potential cost savings from this change.

2.5.6 Interactions between auction design and other actions to align the Capacity Market with net zero

It is useful to consider how the introduction of a low carbon split auction might interact with the other proposals relating to agreement lengths and projects with long build times considered in sections 2.3 and 2.4 respectively. For example, if eligibility for long multi-year capacity agreements of up to fifteen years was tied to a new lower emissions limit (as examined in section 2.3.2), then these long agreements could be made available specifically via a separate low carbon auction. Similarly, as discussed in section 2.4.2, a separate low carbon auction could provide a route for limiting access to, and addressing the security of supply risks associated with, the option of a declared later delivery year.

Moreover, as noted in section 2.1, we would also need to consider further how innovations such as the introduction of a separate T-4 auction for new build and refurbishing low carbon capacity could interact with wider changes in the policy landscape as the power sector is decarbonised – not least because the Capacity Market is one of many routes to market which could be available for low carbon capacity, and (at least in the short-medium term) may not be the main route for such capacity.

In light of both of these considerations, we welcome views on how the design possibilities explored in Chapter Two – concerning agreement lengths, projects with long build times, and auction design – might interact with each other. We also welcome views on other potential changes we could make to better align the Capacity Market with net zero.

Summary of considerations put forward in section 2.5

- Consider the case for introducing a split auction for new build and refurbishing low carbon capacity. This could involve holding a separate auction alongside the main T-4 auction, or introducing multiple clearing prices into a single T-4 auction.

- Undertake additional analysis on auction design to ensure any changes made would be consistent with our policy objectives.

- Consider expanding the scope of the Price Taker Threshold such that it could act as an effective price cap to Price Taker capacity.

- Consider amending the Net Welfare Algorithm to calculate to next lowest bid, rather than by the round floor price.

- Explore further how potential changes to auction design could interact with the changes to agreement lengths and for supporting projects with long build times in sections 2.3 and 2.4, and with the wider net zero policy landscape.

Questions on considerations in sections 2.5

Question 13

What are your views on the benefits and challenges of introducing an auction design splitting auctions between new build and refurbishing low carbon capacity and existing capacity? Would this affect your decision to participate in the Capacity Market or your bidding behaviour, and if so, how?

Question 14

What are your views on the potential split auction designs considered in sections 2.5.2 and 2.5.3? Are there alternative designs we should consider? And what approach could we take to setting targets for a separate low carbon auction?

Question 15

What are your views on expanding the scope of the Price Taker Threshold to potentially make it a price cap for Price Taker Capacity? Would this impact bidding behaviour? What changes to the Price Maker Memorandum might be necessary to ensure any changes to the Price Taker Threshold would be effective?

Question 16

What are your views on the potential benefits or challenges of amending the Net Welfare Algorithm to calculate to next lowest bid, rather than by the round floor price? Would this have an impact on bidding behaviour?

Question 17

How might the changes to auction design considered in section 2.5 interact with other design possibilities explored in Chapter Two concerning agreement lengths (2.3) and projects with long build times (2.4)?

3. Short Term Considerations: Improving Delivery Assurance

3.1 Penalties

3.1.1 Context

Winter 2020/21 witnessed more volatile wholesale prices and an increase in the number of Electricity Margin Notices and Capacity Market Notices issued relative to previous years. Whilst the Reliability Standard of three hours LOLE was achieved, the greater non-delivery of capacity, a higher proportion of plants reaching the end of their operational lives, and an increased volume of capacity not registered as a Balancing Mechanism Unit (BMU) and therefore not visible to NGESO, all contributed to creating tighter operational margins than previously seen since the introduction of the Capacity Market.

As more large generation (including all unabated coal, the majority of the nuclear fleet, and some gas-fired plant) reaches the end of its operational life, and more capacity is installed which is not registered as a BMU (such that the NGESO has limited visibility of this capacity), the risk of tighter margins is likely to remain in the short to medium term.

Furthermore, the anticipated evolution of the electricity sector will see a greater volume of renewables on the system (exemplified by the government's ambition to have 40 GW of offshore wind by 2030) and dispatchable generation retiring, such as the closure of older gas-fired generation in the coming decade. In addition, BEIS modelling suggests that electricity demand could double by 2050. Combined, these factors mean there will likely be greater pressure on capacity margins when renewable output is lower. Hence, the Capacity Market will need not only to bring forward the right capacity to replace retiring capacity, provide flexible capacity to support intermittent renewables, and ensure there is sufficient capacity to meet growing electricity demand, but will also need to ensure that procured capacity has the right incentives to deliver when required.

As the electricity system evolves to meet net zero, and for the reasons discussed above, the need for capacity to deliver when required is more important than ever. One of the key mechanisms available in the Capacity Market to incentivise delivery is the penalty regime. Given the issues discussed, we are keen to explore potentially strengthening the penalty regime to help improve assurance that capacity will deliver when required.

3.1.2 Introduction

The main purpose of a penalty regime, in the context of capacity mechanisms, is to ensure adequate incentives are in place for capacity providers to deliver their obligations when required. Penalties ensure providers are exposed to an economic signal which in the short-term incentivises availability of capacity and delivery during stress events, and over the longer term incentivises investment in reliable and flexible capacity.

Under the Capacity Market, capacity providers are required to deliver their capacity obligation during stress events or face financial non-delivery penalties.[41] Strengthening the penalty regime was one of the priority issues identified through the Five-year Review. This followed industry responses (provided during the Capacity Market Call for Evidence held between August and October 2018) which argued the current arrangements may be too weak to incentivise capacity providers appropriately to deliver during system stress events in all circumstances.[42]

Our view is that there is a need to explore potentially strengthening the Capacity Market penalty regime. The 2020/21 Delivery Year witnessed greater amounts of non-delivery of capacity and, for the reasons discussed in Section 3.1.1, we believe the increased risks of tighter capacity margins means effective incentives need to be in place to ensure delivery of capacity when required.

During the original design phase of the Capacity Market, a key consideration was the need to incentivise new capacity to come forward by providing effective investment signals, and a strong penalty regime was considered to detract from that. The Capacity Market has been running effectively since 2014, and we believe the market is now comfortable with the Capacity Market as an investment proposition. Given the concerns raised through the Five-year Review, we are seeking views through this Call for Evidence on ways in which the penalty regime could be strengthened and possible broader changes to the penalty regime.

3.1.3 Current arrangements

Under current arrangements,[43] capacity providers that do not deliver sufficient capacity to meet their capacity obligation during system stress events are required to pay a penalty called a Capacity Provider Penalty Charge. The penalty rate is set at 1/24 of the £/MW clearing price for the capacity obligation awarded to the CMU in the relevant capacity agreement. The penalty charge is calculated by multiplying the penalty rate and the difference between the CMU's adjusted net output during the stress event and its adjusted load-following capacity

[41] See Regulation 41 of the Electricity Capacity Regulations 2014. Financial penalties associated with termination events known as "termination fees" are not the subject of this call for evidence.
[42] See pages 14 -15 of the Capacity Market and Emissions Performance Standard Review: Summary of Call for Evidence Responses.
https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/784315/cm-and-eps-review-summary-of-cfe-responses.pdf
[43] See Regulation 41 of the Principal Regulations, paragraphs 5, 6 and 6A of Schedule 1 to the Principal Regulations. And for the penalty caps see Regulation 31(f) and 41. See also EMRS Guidance, G17 – Capacity Provider Payments: https://www.emrsettlement.co.uk/documentstore/guidance/g17-capacity-provider-payments.pdf

obligation (ALFCO). The penalty charge is capped at 200% of the CMU's monthly capacity payments, and annually at 100% of the CMU's annual capacity payments.[44]

A capacity provider failing to deliver any capacity during a system stress event may, in four hours of non-delivery, incur penalties that reach the monthly penalty cap. Monthly capacity payments are weighted according to system demand, so capacity providers may be exposed to a penalty of up to 20% of their annual capacity payments each month. In practice, a capacity provider could therefore completely fail to deliver against their capacity obligation during five separate stress events across five different months, each lasting around four hours, before reaching the annual penalty cap.

It is, therefore, very unlikely that a capacity provider which failed to deliver against its capacity obligation would incur penalties equivalent to its annual capacity payments. Modelling by NGESO has shown that we could expect on average one or two stress events, each with a duration of around two hours for a system with three hours LOLE.[45] Even if the CMU completely failed to deliver any capacity during all these expected stress events in an average year, the most the capacity provider could expect to pay in penalties is 20-25% of the CMU's annual Capacity Market revenues. This supports the feedback received during the Five-year Review that the penalties are too weak to effectively incentivise participants to deliver reliable and flexible capacity during system stress events, and that capacity payments may be seen as a source of revenue to be drawn without fulfilling the corresponding obligation.

When considering the adequacy of arrangements, it is also worth noting that whilst penalties apply to all types of capacity equally, their impact can vary. For example, conventional Balancing Market Units (BMUs)[46] are already exposed to strong incentives to deliver in a stress event (e.g. through prices in the wholesale market and balancing mechanism) and the Capacity Market penalties act to reinforce these other signals, whereas some other types of capacity provider (e.g. non-BMUs) may be exposed to fewer/weaker signals in the wider market to deliver during system stress, making the significance of the Capacity Market penalties more important. Whilst the changes to penalties discussed in this chapter would not alter wider market signals, they could provide a stronger financial incentive for capacity with fewer wider market signals to deliver when required to avoid non-delivery penalties.

In our recent Capacity Market Consultation,[47] we proposed a requirement for all CMUs to be registered as BMUs, which we outlined would improve NGESO's visibility of assets on the

[44] Penalties are calculated on a monthly basis if one or more system stress events has occurred during a Delivery Month. Late payment interest is payable on any unpaid capacity provider penalty charges and if they remain unpaid, they are netted off against future Capacity Payments. There are two calculations used to determine the penalties payable by a capacity provider: the settlement period penalty and the monthly penalty charge. At a basic level, a capacity provider must pay the penalty charge in respect of any month in which a settlement period penalty applies to its CMU. The penalty charge is what Capacity Providers actually pay and is the sum of all settlement period penalties for any given month, but capped at either the monthly or annual penalty cap (whichever is the lesser amount).

[45] https://www.emrdeliverybody.com/Lists/Latest%20News/Attachments/150/Duration%20Limited%20Storage%20De-Rating%20Factor%20Assessment%20-%20Final.pdf

[46] A unit of capacity that participates in the Balancing Mechanism.

[47] https://www.gov.uk/government/consultations/capacity-market-2021-proposals-for-improvements

system and therefore their ability to manage security of supply. If these changes were implemented, then CMUs registered as BMUs would be exposed to additional incentives to deliver. However, we believe that Capacity Market penalties would still be required to ensure sufficient incentives were in place for a CMU to deliver capacity when required.

3.1.4 Design considerations

The most important design consideration is to identify the appropriate severity of 'penalty rate' to which capacity providers should be exposed (see section 3.1.4.1).

It is also important to consider what measures might be necessary to achieve a balance between exposing capacity providers to strong economic incentives to ensure capacity providers deliver against their capacity obligation (through penalties), and ensuring the Capacity Market mechanism continues to bring forward capacity at an acceptable cost (through limiting capacity providers' exposure to penalties via approaches such as maintaining some form of penalty cap, and helping reduce exposure to penalties by providing advance notice of delivery/penalties).

Other design considerations include:

- how to ensure that capacity providers who have already incurred penalties up to a penalty cap remain incentivised to deliver in possible future stress events;
- non-financial penalties;
- over-delivery payments;
- how to recover penalties in the event of non-payment; and
- the potential impact of changes to the penalty regime on other aspects of the Capacity Market's design, including secondary trading, de-rating factors and Satisfactory Performance Days (SPDs).

3.1.4.1 Penalty rate

Whilst we believe there is a strong case for reviewing the severity of non-delivery penalties, views on the 'optimal' penalty rate are likely to be highly subjective and dependent on how individual capacity providers perceive the balance between risk and reward in the Capacity Market. This, in turn, is likely to vary according to the risk appetite of individual capacity providers, their view of the probability of stress events, and their ability to mitigate risk.

Currently, the penalty rate for a settlement period[48] is calculated in accordance with the formula:[49]

[48] "Settlement period" is defined as a period of 30 minutes beginning on an hour or half-hour: regulation 2(1) of the Principal Regulations.
[49] Paragraph 5 of Schedule 1 to the Principal Regulations.

Penalty rate (expressed in £/MWh) = clearing price[50] (£/MW) x 1/24[51]

To ensure the Capacity Market penalty regime provides an effective incentive to deliver capacity when required, we are considering increasing the figure used in calculating the penalty rate from 1/24 to 1/8.

Capacity Market clearing prices to-date have varied considerably, from £0.77/kW in the T-1 for DY 2019/20 to £45.00/kW in the T-1 for DY 2021/22, so penalty rates based on capacity payments will similarly vary in level. Based on the range in clearing prices we have seen to-date, the penalty rate using the current formula varied between £32/MWh and £1,875/MWh. The proposed change to the formula would have meant penalty rates between £96/MWh and £5,625/MWh. This is still considerably lower than the Value of Lost Load (VoLL) estimated at £17,000/MWh; however, the proposed change could provide comparable incentives to the Balancing Mechanism – the penalty rate would equal the high imbalance price of £4,000/MWh seen in January 2021 with a Capacity Market clearing price of £32/kW.

Stress events may, in practice, be more or less frequent than modelling by National Grid ESO suggests.[52] For example, forecast LOLE in winter 2020/21 was less than 0.1hrs[53] and so the chances of a system stress event were low. It may, therefore, be prudent to set a higher figure of 1/4 to disincentivise potential gaming by providers risking the chance of a System Stress Event to be low. We would welcome views on which of these possible figures or an alternative could be used in calculating a potentially strengthened penalty rate (1/8, 1/4 or an alternative) and which would strike an appropriate balance between risk and reward in the CM.

3.1.4.2 Penalty rate connection to the auction clearing price

The discussion in Section 3.1.4.1 focuses on linking a penalty rate to the clearing price. This has been the design since the Capacity Market was introduced. While it has some evident advantages, there are also disadvantages to linking the penalty rate to the clearing price. For example, the severity of the penalty, and therefore the incentive to deliver, can vary between capacity providers according to auction outcomes, even with respect to the same delivery year. Additionally, if the annual penalty cap were to be increased above 100% of annual Capacity Payments, as discussed in Section 3.1.3.3, this could further exacerbate the difference between providers' exposure to penalties and risk according to auction outcomes.

There are, however, advantages to retaining a penalty rate linked to the clearing price. For example, it is more closely aligned with the objective of ensuring the Capacity Market is not seen as a source of revenue without any corresponding obligation to deliver, and there is a clear link to our discussion on the benefits of amending the penalty cap in Section 3.1.4.2. Moreover, this approach is already well understood by stakeholders and retaining it limits the

[50] Clearing price for the capacity obligation awarded to the CMU in the relevant capacity agreement.
[51] The penalty rate for a Capacity Obligation is 1/24th the relevant auction clearing price.
[52]https://www.emrdeliverybody.com/Lists/Latest%20News/Attachments/150/Duration%20Limited%20Storage%20De-Rating%20Factor%20Assessment%20-%20Final.pdf
[53] https://www.nationalgrideso.com/publications/winter-outlook

number of changes needed to the Capacity Market legislation, and processes and calculations by the Settlement Body.

Whilst we still believe there are benefits to linking the penalty rate to the clearing price, we are seeking views on the potential benefits and challenges of linking the penalty rate to the Value of Lost Load (VoLL). The Capacity Market is designed to ensure security of electricity supply in GB and so the use of VoLL as the metric for the non-delivery rate could be appropriate as penalties would be aligned to the damage costs of non-delivery. A standardised value would also arguably provide investor confidence relative to a variable penalty rate linked to the auction clearing price.

However, one difficulty with this approach is that VoLL is subjective and very difficult to estimate. The value of VoLL we currently use to inform our reliability standard for the Capacity Market is £17,000/MWh. This equates to £17/kW for every hour of loss of load, if there were three hours of loss of load in the year this would equate to £51/kW. This price is higher than any Capacity Market clearing price seen to date and is also higher than the maximum level of termination fees of £35/kW.

We are considering undertaking a future review of VoLL, including whether VoLL should be static, single valued, or should vary to reflect a stress event's breadth, which could impact more capacity providers, or its duration, which would be more impactful the longer the stress event lasts. We recognise that a possible future review of VoLL introduces uncertainty to the decision on whether it forms a suitable basis for the Capacity Market penalty regime.

3.1.4.3 Annual penalty cap

An annual penalty cap, which places an upper limit on the amount of penalties that a CMU can incur in any one delivery year,[54] is one way of reducing the risk of a capacity provider's exposure to penalties and, therefore, ensuring the Capacity Market can bring forward the necessary capacity at an acceptable cost as capacity providers calculate their risk of penalty exposure and reflect it in their bidding behaviour. It is important to set it at the right level – too low and it will not incentivise performance of Capacity Market delivery obligations nor deter market manipulation, too high and it may deter participation in the auctions or drive up clearing prices.

The annual penalty cap is currently set at 100% of a CMU's capacity payments in the relevant delivery year.[55] The penalty caps means that, even if a CMU failed to deliver any capacity during multiple stress events, it would never lose more money than it received in Capacity Market payments. Consequently, the Capacity Market is viewed by some as a source of revenue which can be drawn without needing to fulfil the corresponding obligation. In turn, this increases security of supply risks.

The government is, therefore, seeking views on whether to increase the annual penalty cap to a level above 100% of annual capacity revenues. Our initial view is that this figure could be set

[54] "Annual penalty cap" is defined in regulation 2(1) of the Principal Regulations.
[55] Regulations 31(2)(f) and 41(3A)(a) of the Principal Regulations.

between 101% - 150%; however, we would welcome views on where in this range the cap should be set to achieve a balance between perceived risk and reward.

3.1.4.4 Ensuring the introduction of an annual cap does not undermine the incentive effect

An annual cap on its own may not sufficiently limit a capacity provider's exposure to risk. Moreover, once a cap is reached, capacity providers are no longer incentivised via the penalty regime to deliver (albeit wider market signals should continue to incentivise delivery in most circumstances, as many capacity providers participate in the wholesale and balancing markets where prices will be higher in periods of system stress).

Currently, there is a monthly penalty cap (the maximum amount of penalty charges payable in a month), which is set at 200% of monthly capacity payments payable to the capacity provider for that month.[56] However, whilst this does further limit a capacity provider's exposure to risk in addition to the annual cap, it potentially prevents the accruing of penalties which adequately reflect the impact of non-delivery if a capacity provider fails to deliver in multiple stress events within a single month.

To address this, the government is considering replacing the monthly cap with a penalty cap for each stress event. The 'stress event' cap could be set at between 75% and 100% of the CMU's Capacity Market payments for the relevant delivery year. This range could strike a balance between providing strong incentives for delivery during a System Stress Event, and sufficiently limiting exposure to risk. It is worth noting that the point at which this limit is set will be dependent to some extent on the level of the annual cap described earlier. For example, if the revised annual cap is set at 101%, then there would be little value in implementing a stress event penalty cap at 100%.

We consider that a stress event penalty cap should ensure a proportion of the annual penalty cap is held back to incentivise delivery in case there is more than one stress event in a delivery year, but it should also ensure that the annual cap could be reached by non-delivery of two stress events, thereby reducing the risk that the Capacity Market is perceived as a source of revenue free of any corresponding obligation to deliver.

It is also worth noting that there are currently arrangements in place which enable capacity providers to reduce their penalty exposure by delivering at least some of their delivery obligation during a stress event. The following formula is applied in the event of partial delivery during a stress event:

Penalty adjustment factor = total penalty for a stress event (actual performance) ÷ Max penalty for stress event (theoretical zero delivery)

[56] Regulations 31(2)(f) and 41(3A)(b) of the Principal Regulations.

Whilst this does weaken the penalty rate, it ensures that capacity providers continue to be incentivised to deliver during extended stress events and as they approach any of the penalty caps. We are therefore not proposing to remove or amend this arrangement.

3.1.4.5 Other measures to limit risk to participants

Advance warning of delivery can also reduce capacity providers' risk. Capacity providers currently receive a Capacity Market Notice four hours ahead of a possible stress event – penalties are not applied during this period even if a stress event commences within this four-hour window. Whilst this limits capacity providers' risk, it effectively allocates security of supply risks onto the consumer. It may also weaken incentives for investment in flexible capacity beyond that required to deliver within this four-hour timeframe.

As stated in our Five-year Review,[57] we recognise that there is a need to consider the co-ordination of capacity during a stress event in more detail. We will work with the Delivery Body and NGESO to improve our collective understanding of the challenges in co-ordinating different types of capacity through different markets and identify and assess potential solutions to mitigate these issues, so that the Capacity Market remains robust for future market evolution. Options may include better information on the likely nature of the stress event in the run-up to an actual event, amendments to the calculations and/or sensitivities within the Capacity Market Notice, or removal of the four-hour notice period. Recent and ongoing developments, such as the recent consultation proposal for all CMUs to be registered as BMUs,[58] may also help to provide a way forward.

3.1.4.6 Non-financial penalties

To provide a further delivery incentive, the government is considering introducing a requirement for CMUs that fail to deliver in a stress event to undertake an additional Satisfactory Performance Day (SPD) within one or two months of the stress event. This requirement could extend the current requirement in Rule 13.4.6 in the Capacity Market Rules that requires CMUs which do not deliver capacity over two or more months following a System Stress Event to meet six rather than three SPDs within the SPD period. We would welcome views on this proposal.

3.1.4.7 Over-delivery payments

The potential to receive payments to reward over-delivery will also affect a capacity provider's view of the balance between risk and reward in the Capacity Market. Arrangements are already in place to reward over-delivery, which include:

- selling over-delivery volumes to other capacity providers immediately following a stress event i.e. volume reallocation;[59] and
- over-delivery payments at the end of the delivery year paid from the capacity provider penalty charges pot (i.e. all penalty payments for non-delivery during the year are

[57] Page 43 – 44
[58] https://www.gov.uk/government/consultations/capacity-market-2021-proposals-for-improvements
[59] See Chapter 10 of the Capacity Market Rules.

collected and then shared out amongst CMUs that have over-delivered, ignoring any over-delivery that has gone through volume reallocation).[60]

The government does not intend to amend these arrangements as they appear to be satisfactory and are likely to be strengthened if some or all of the other proposals in Section 3.1.4 are implemented.

3.1.4.8 Recovery of penalties in the event of non-payment

Increasing the penalty rate and annual cap increases the risk that capacity providers could be unable to meet or might seek to avoid the payment of penalties. Therefore, robust arrangements are needed to ensure there is scope to recover any non-payment of penalties from providers.

There appear to be two options in this regard:

- recover any unpaid penalty from future Capacity Market payments (as is currently the case); or
- require all capacity providers to post and maintain credit cover to help cover the cost of potential penalties.

In relation to the first option, if the annual penalty cap is set above 100%, there is a greater likelihood that the recovery of penalties from future capacity payments may need to roll-over into future delivery years and in relation to future Capacity Market agreements. This may reduce the incentive for capacity providers to participate in future auctions and limit the scope for recovery of payments. However, requiring all capacity providers to finance credit cover for an extended period of time could place an upward pressure on auctions bids and clearing prices, and at worst could act as a disincentive to participation. Therefore, the government is currently minded to maintain the present arrangements (i.e. recover any unpaid penalties from future Capacity Market payments).

3.1.5 Alternative penalty regime: capacity payment loss

The preceding discussion of potential changes to the penalty regime presupposes that our approach will be to build upon the current penalty regime. However, the current regime is complex in the application of penalties, with numerous variables which could create uncertainty as to the potential level of penalty applied. We are therefore seeking views on possible alternative approaches.

For example, we could consider a penalty regime whereby Capacity Market payments are lost for a pre-determined number of months (e.g. two months) in the event of any non-delivery of capacity in a stress event. This could provide a much clearer and simpler way of applying penalties and incentivising delivery.

This approach could have a number of advantages. For example, it could effectively strengthen the penalty regime in line with feedback from the Five-year Review. The

[60] See Regulation 42 of the Principal Regulations 2014.

suspension could be applied at a ‘flat rate’ of two months regardless of the number of settlement periods missed and not weighted according to system demand. This could strengthen the penalty applied, and as the total payment would be known in advance, it would be easier for capacity providers to calculate the level of risk of non-delivery for capacity providers.

To reduce a capacity provider’s exposure to unreasonable risk, a tolerance could be applied. For example, non-delivery of capacity within a pre-determined range of an obligation would not result in a loss of payments being triggered. This tolerance could be set within a range of (for example) one and ten percent of the capacity provider’s overall obligation.

In the event of non-delivery across multiple stress events, the severity of the suspension could be consolidated in two monthly increments. For example, failure to deliver in one stress event could incur a loss of two months’ capacity payments and failure to deliver in a second stress event could result in an additional four months of suspended payments. In the event the suspensions extend beyond the delivery year, the suspension would roll over into following Delivery Years and impact future Capacity Market agreements. The timing of the suspensions would also need to be considered to enable sufficient time for volume reallocation to occur to establish whether a penalty might be applied to a capacity provider.

In this scenario, six months loss of payments is still not a significant disincentive for failure to deliver in two stress events and equates to a penalty cap of 50% of a capacity provider’s capacity obligation. It could be strengthened further, with non-delivery in a third stress event in one delivery year resulting in that CMU’s termination from the Capacity Market as the CMU has not provided the required capacity and so is not contributing to security of supply. The loss of payments could, however, represent two extremes. On the one hand, failure to deliver significant volumes of capacity could result in a 50% penalty rate, albeit with a risk of termination for a third non-delivery. On the other, a relatively small proportion of capacity not delivered over the tolerance would be punished with up to six months loss of payments or possibly termination.

Capacity providers could face financial burden during the months of lost payments. If this burden prevented a capacity provider from operating this could create security of supply risks. To reduce this risk, capacity providers could self-nominate the months during which the penalty occurs. This could ensure capacity providers continue to receive payments during the winter months when security of supply risks are higher.

Finally, applying penalties via suspension of payments could create operational efficiencies and decrease the cost of operating the Capacity Market relative to the current system by reducing the administrative complexity of calculating individual penalties.

A penalty regime based on payment losses could increase the strength of penalties applied to capacity providers, but the loss of up to six months of capacity payments could be considered disproportionately high compared to the current penalty regime. However, there are also scenarios in which this alternative penalty regime could prove to be less stringent than the current approach. For example, if the non-delivery was significant in two stress events this would equate to a penalty cap of 50% of a capacity provider's obligation, which would be lower than the cap applied under the current rate and substantially lower than the possible caps proposed in Section 3.1.4.3. This alternative design is therefore unlikely to strengthen incentives to deliver capacity during a system stress event and so our preference is to retain and build upon the current penalty regime.

Summary of considerations put forward in section 3.1

- Consider increasing the figure used in calculating the penalty rate from 1/24 to (for example) 1/8.

- Consider whether to link the penalty rate to the Value of Lost Load (VoLL) rather than the auction clearing price.

- Consider increasing the annual penalty cap to a level above 100% of Capacity Market revenues.

- Consider replacing the monthly penalty cap with a penalty cap for each stress event.

- Undertake further work to consider options on improving the coordination of capacity in a stress event.

- Consider whether to require CMUs that fail to deliver in a stress event to undertake an additional Satisfactory Performance Day.

- Consider options to recover any non-payment of penalties from providers, including recovering unpaid penalties from future Capacity Market payments, or requiring providers to post and maintain credit cover to help cover the cost of potential penalties.

- Consider alternative approaches to the penalty regime, such as the loss of capacity payments for a pre-determined number of months in the event that a provider fails to deliver during a stress event.

Questions on considerations in section 3.1

Question 18

What are your views on changing the figure used in calculating the penalty rate (for example, from 1/24 to 1/8 or 1/4)? Should the penalty rate be linked to the Value of Lost Load rather than the auction clearing price? Please provide supporting reasons/evidence.

Question 19

What are you views on the changes we consider in relation to the annual and monthly penalty caps?

Question 20

What are you views on the options we consider for improving the coordination of capacity during a stress event?

Question 21

Do you agree with the idea of introducing an additional Satisfactory Performance Day for CMUs that fail to deliver in a stress event?

Question 22

What are your views on the options we set out regarding the recovery of unpaid penalties?

Question 23

Would you expect any of these changes to the penalty regime to affect your decision to participate in the Capacity Market, your bidding behaviour, or the costs of and access to finance, and, if so, how?

Question 24

What are you views on the benefits and challenges of the alternative model for a penalty regime set out in section 3.1.5? Are there other models we should consider?

3.2 Connection capacity

3.2.1 Context

Connection Capacity is the total export capacity available to a generation or interconnector CMU on the distribution or transmission network. Currently, Connection Capacity for existing generating CMUs is determined at prequalification by applying the relevant process in the Capacity Market Rules.[61] Prequalification applicants self-nominate their Connection Capacity based on the Grid Connection Agreement for Transmission CMUs or the Distribution Connection Agreement for Distribution CMUs, or an estimate of capacity based on information otherwise contained within those agreements.

As noted in our Five-year Review, allowing prequalification applicants to self-nominate their Connection Capacity opens up a risk that some may seek to over-state their CMU's Connection Capacity in an attempt to circumvent the impacts of de-rating – i.e., that a participant would self-nominate an inflated Connection Capacity figure to offset the amount of capacity 'lost' to de-rating. Any over-stating of Connection Capacity may result in consumers paying for capacity which cannot be relied upon or is not available as the nominated capacity is potentially greater than the CMU can deliver, adding to the cost of auctions and potentially increasing risks to security of supply. We are therefore seeking views on how we can strengthen the existing arrangements for determining Connection Capacity.

Ofgem has previously consulted on changes to the way in which Connection Capacity is determined for generating CMUs at prequalification.[62] Currently, under Rule 3.5.3, an applicant may nominate Connection Capacity based on 'average output',[63] which is the mean average of three separate settlement periods in the previous 24 months with an output above de-rated capacity.

Ofgem's preferred approach for existing Transmission-connected generating CMUs, following its consultation, is summarised below:

- Capacity Providers are allowed to choose their own Connection Capacity during prequalification (their "nominated capacity") – the nominated capacity should not be more than the maximum that a CMU can deliver and would be de-rated to form the bidding capacity of the CMU;
- Capacity Providers are required to demonstrate they are able to reach their full nominated capacity by submitting the average of their three highest metered outputs during the 12 month period between April and March ahead of Prequalification for the T-1 auction (a new "Connection Capacity test");

[61] See Rules 3.5-3.5B.
[62] https://www.ofgem.gov.uk/publications-and-updates/statutory-consultation-amendments-capacity-market-rules-2014-0
[63] Defined in Rule 3.5.4.

- If the connection capacity test result is lower than the nominated capacity, the CMU's Capacity Obligation should be reduced proportionally to match the tested output, de-rated, and therefore the capacity payments should also be reduced accordingly. If the test result is equal to or above the nominated capacity, no change should be made to the Capacity Obligation;
- Capacity Providers would also face a financial penalty if the test result fell below 97% of the nominated capacity. The financial penalty should equal the deviation from the 97% threshold (measured in kW) multiplied by the termination fee level (£35/kW).

Overall, stakeholders were supportive of Ofgem's proposals,[64] including the approach to testing connection capacity and the need for financial penalties to incentivise participants to correctly state their capacity. However, Ofgem identified that some changes to the Principal Regulations will be necessary (for example, the introduction of financial penalties), and so requested input from BEIS to progress these policy proposals. The government intends to advance Ofgem's policy proposals with some adjustments as set out below.

This Call for Evidence seeks further evidence from stakeholders on some specific aspects of the technical changes required in order to develop detailed consultation proposals. As noted by Ofgem, we have no evidence to suggest that the existing testing arrangements for New Build and Refurbishing CMUs are insufficient, and so we are not minded to change these Rules. However, any changes would apply to interconnectors.

3.2.2 Demonstration of connection capacity by wind and solar CMUs

Some wind and solar plant may be unlikely to output at their full Connection Capacity (or 97% of their Connection Capacity) on three separate occasions during the course of the year and consequently may routinely fail the proposed test. Applying a new test and threshold to wind and solar would, therefore, be unreasonable, particularly given the methodology for determining the de-rating factors for these Generating Technology Classes already takes into account the variability of their output due to weather.

Whilst we consider that it is still necessary to test the Connection Capacity of wind and solar to mitigate the risk of providers over-stating their Connection Capacity, we believe it would be appropriate to establish alternative arrangements for these types of generation. Given available output data for wind and solar is limited, we wish to seek views and evidence on what percentage of Connection Capacity wind and solar could reasonably expect to meet three times a year. For example, the threshold could be set between 80%-90% of nominated capacity, which may account for their variability in output.

Alternatively, if it is not possible to identify a reasonable threshold, we may have to continue relying on current arrangements for demonstrating Connection Capacity in relation to wind and solar CMUs.

[64] https://www.ofgem.gov.uk/publications-and-updates/decision-statutory-consultation-amendments-capacity-market-rules-2018

We welcome views on this or any alternative arrangements for wind and solar to demonstrate Connection Capacity.

3.2.3 Demonstration of connection capacity by distribution connected CMUs

We are minded to extend the proposed Connection Capacity test to distribution-connected CMUs in addition to transmission-connected CMUs, as originally proposed by Ofgem. We do not believe that differential treatment is justified or necessary, and it could introduce a risk of distorting competition between the two categories of CMU.

3.2.4 Co-located CMUs

Some CMUs are co-located on the same site as other CMUs and share the same connection to the distribution or transmission network. We are concerned that the overall capacity procured through these ‘co-located CMUs’ may not be available during a stress event if the total capacity of each CMU combined exceeds the capacity of the connection point to the network. For example, if three generating units with a de-rated capacity of 400 MW each were connected to the grid via a single connection point with a capacity of 1,000 MW, there could be a capacity shortfall of 200 MW if the system stress event demanded full output by all three units. It is vital that all capacity procured through the Capacity Market is available and can deliver its capacity obligation when required. We are therefore seeking views on how to ensure co-located CMUs can deliver their total capacity when required.

An option could be an extension of any new Connection Capacity test, whereby separate CMUs connected to the same section of the distribution or transmission section must collectively demonstrate that their combined generating capacity does not exceed the capacity of their shared connection to the network. We are aware such a test could place additional burdens on capacity providers, particularly where the CMUs have different owners and so collaboration between different parties would be required. We welcome views on the challenges and possible solutions to this issue.

3.2.5 Timing of the Connection Capacity Test

Following Ofgem’s consultation on its proposals, there were a variety of views amongst respondents on when the proposed connection capacity test should take place. We are therefore seeking views on the following options:

- For existing generation CMUs that secure agreements in a T-4 auction, the test should be completed in the 12 month period before: (i) February prior to the T-1 targets being set;(ii) the T-1 targets are finalised in October; or (iii) one month before the start of the delivery year.
- For existing generation CMUs that wish to participate in a T-1 auction, the test should be completed in the 12 month period before either: (i) the February ahead of prequalification for the auction; or (ii) one month before the start of the delivery year.

Our preference in both instances is for the test to be undertaken by the February ahead of prequalification for the T-1 auction, as this minimises risks to security of supply. In relation to capacity secured through the T-4 auction, the proposed timing ensures there is an opportunity to adjust the T-1 target to replace any capacity that is lost in the event any CMUs fail to meet the connection capacity test. In relation to the T-1 auction, this timing avoids the risk of losing any capacity following the T-1 auction.

However, we are aware that there may be practical difficulties with complying with the test to this timeframe, particularly in relation to mothballed capacity, and would welcome views and evidence of the impact of each proposed option.

Summary of considerations put forward in section 3.2

- Consider options for advancing Ofgem's proposal for the introduction of a Connection Capacity test, including exploring appropriate testing arrangements for wind and solar capacity, for distribution connected CMUs, and for co-located CMUs.

- Consider the appropriate timing for the Connection Capacity Test, noting a preference for the test being undertaken by the February ahead of prequalification for the T-1 auction to minimise risks to security of supply.

Questions on considerations in section 3.2

Question 25

What are your views on appropriate testing arrangements for wind and solar CMUs, distribution connected CMUs, and co-located CMUs?

Question 26

Which is your preferred option of those proposed in section 3.2.5 relating to the timing of the connection capacity test? Are there alternative approaches we could consider?

3.3 Capacity obligations of CMUs that have been terminated

3.3.1 Context

In our recent consultation[65] on the Capacity Market, we put forward proposals to prevent secondary trades from being cancelled in the event of a transferor termination. The intention behind this was to improve security of supply by ensuring that secondary trading can be used to replace capacity that closes at short notice during the Delivery Year. However, these proposals are reliant on the transferor engaging in secondary trading prior to closure, which may not always happen. We are therefore considering whether it would be beneficial to enable a third party (such as the Delivery Body) to re-auction any remaining capacity obligation associated with a CMU that has been terminated during the delivery year, or between a capacity auction and the start of the relevant delivery year. This would maximise the opportunity for finding a buyer for the remaining capacity at short notice, thereby avoiding the loss of potentially significant volumes of capacity.

3.3.2 Principles for a third-party arrangement

Whilst we do not have a firm proposal on this yet, our initial view is that introducing the ability of a third party to re-auction Capacity Market agreements could be based upon a model with the following elements:

- The third party communicates opportunities for secondary trades of remaining capacity obligations of CMUs which have been terminated to stakeholders and provides initial facilitation of relationships between buyers and sellers.
- The third party invites and facilitates bids from eligible transferees up to the value of the terminated capacity obligation (e.g. on a pay as bid basis) and then awards some or all of the capacity to the lowest price bidder/s. Independent monitoring of the auction process would be needed.
- A methodology would be applied whereby if the lowest priced eligible transferee could only take on a proportion of total capacity obligation, then additional portions of the capacity obligation would be sold to the next lowest bidder/s. This could be similar to the Net-Welfare Algorithm[66] in the main auctions.
- Ensure that, if the terminated capacity held a multi-year agreement, only the capacity obligation for the current delivery year would be auctioned. The obligation for future years would be replaced through the associated T-4 and/or T-1 auctions.
- Ensure that the eligible transferee would only be able to take on the capacity obligation for the remainder of the delivery year.
- A methodology would be applied which aligns with Rules in respect of carbon emissions, to ensure that if two transferees submit the same priced bid for exactly the

[65] Capacity Market: 2021 Consultation on improvements. (See sections 2.4.3 and 2.4.4) https://www.gov.uk/government/consultations/capacity-market-2021-proposals-for-improvements
[66] i.e. the process applied in respect of auction clearing - see Rule 5.9.

same proportion of the capacity obligation, then the one with the lowest carbon intensity would win. This would require appropriate arrangements to be established for reporting and comparing emissions data.

Other key considerations include whether we would need to establish a minimum threshold for triggering this trading process based on the significance of the anticipated loss of capacity. Similarly, we may wish to consider placing a time limitation on trading – for example, if the winter of the relevant delivery year has already passed, it may not be necessary from a security of supply perspective or good value for money for the remainder of the obligation to be traded. In assessing the benefits of this approach, we also need to consider the likelihood of transferees being able to deliver replacement capacity at such short notice during the delivery year, and whether there are alternative approaches we could take to ensure security of supply in respect of CMUs which have been terminated without fully or partially trading their capacity obligations.

Summary of considerations put forward in section 3.3

- Consider enabling a third party (such as the Delivery Body) to re-auction any remaining capacity obligation associated with a CMU that has been terminated during the delivery year, or between a capacity auction and the start of the relevant delivery year.

- Consider appropriate principles to support the above change, including establishing suitable checks and limitations on the use of this approach.

Questions on considerations in section 3.3

Question 27

Would it be beneficial for us to enable a third party (such as the Delivery Body) to re-auction capacity obligations in respect of CMUs that have been terminated during the delivery year, or between a capacity auction and the start of the relevant delivery year? If so, what are your views on the principles for such an arrangement (set out in section 3.3.2), and do you have any commercial considerations and/or concerns about the use of a third-party facilitator?

3.4 De-rating factors

3.4.1 Context

De-rating factors[67] determine the capacity obligation that can be secured in a Capacity Auction by a given technology class and set the expected level of contribution to security of supply during a stress event by technology type.

The de-rating factors calculated by the NGESO are for each technology type, and so are not necessarily reflective of each individual CMU's risk of non-delivery. For example, an individual CMU in a given generating technology class may be more at risk of non-delivery at different stages in its lifecycle compared to the historic fleet average for a particular technology class, possibly due to maintenance cycles as it approaches the end of its operational life, or due to operational requirements in the case of DSR. The impact may be that the de-rating factor applied to an individual CMU is not reflective of the CMUs ability to contribute to security of supply. Ultimately this could impact whether sufficient capacity is secured to meet the Reliability Standard.[68]

As more capacity approaches the end of its operational life, and as the deployment of distributed generation continues to rise where there are some uncertainties on the behaviour and capacities data for these sites, the calculated de-rating factors may not reflect a CMU's availability. The Panel of Technical Experts raised both these issues in their 2019 report, noting that historic data may not be the most robust way to assess future availability of specific technology types, and that transparent data is needed for embedded generation.[69] They have revisited this second issue in their 2021 report, highlighting the need for better data and the risk that currently the de-rating factors applied to embedded assets will not be as accurate as is desirable.[70]

3.4.2 Adapting our approach to ensure that de-rating factors accurately reflect the risk of non-delivery

For these reasons it may be necessary to adapt our approach to de-rating factors to ensure they continue to reflect a CMU's expected contribution to security of supply. For example, one approach could be to allow capacity providers to decide their own de-rating factors, with the NGESO's calculated de-rating factors acting as an upper limit. The introduction of tougher non-delivery penalties (see Section 3.1) may encourage capacity providers to select de-rating factors more reflective of their CMU's technical performance and risk of non-delivery.

[67] The de-rating factors applied to each CMU type are set out in Rule 2.3.4(a)-(e) and the current methodology for calculating these de-rating factors is set out in Rules 2.3.5 to 2.3.5B.

[68] The Reliability Standard informs the decision on how much capacity is needed to ensure security of supply. The Reliability Standard is three hours of expected loss of load per capacity year, as per Regulation 6(1).

[69] https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/816012/Panel_of_Technical_Experts_report_2019.pdf

[70] https://www.gov.uk/government/publications/national-grid-eso-electricity-capacity-report-2021-findings-of-the-panel-of-technical-experts

Equally, more modest changes may be more appropriate. The current de-rating methodology structure could be amended to better account for the challenges outlined. For example, a de-rating methodology could be designed to be applied specifically to end-of-life capacity. Such an approach, if practical, could enable the reliability of end-of-life plant to be better reflected in the de-rating factors. However, such an approach presents several challenges, including when and how would capacity be determined as entering ‘end-of-life’ and have this alternative approach applied; and what data would give an indication of the future performance of capacity at this stage of its operational life. This is particularly challenging as the de-rating methodology is currently a backward-looking method, drawing on seven years of past performance data, while historic data on end-of-life availability is limited and so is a forward-looking issue. It is not clear what data sources, or methodological approach, would provide a more accurate indication of future performance than the method currently used. A separate approach would also be needed to better reflect the availability of embedded generation, and would also face design and data challenges.

We do not have a firm proposal for how to ensure de-rating factors continue to reflect a CMU’s expected contribution to security of supply, whether this be a change to the de-rating methodology and/or a change in how de-rating factors are applied to an individual CMU. However, we are keen to gather stakeholder views on whether this is an issue, and on potential solutions. Any change in methodology would be subject to consultation by NGESO.[71] We will share the responses to this section with the NGESO to help inform any future consultation on whether the de-rating calculation methodologies achieve their objectives, and/or whether an alternative methodology would be more effective in accordance with Rule 2.3.8.

Summary of considerations put forward in section 3.4

- Consider changing the de-rating methodology with the aim of providing a more accurate reflection of the risk that a CMU may not deliver during a stress event.

- Consider changes to how de-rating factors are applied to end-of-life capacity.

Question 28

In your view, do the current de-rating methodologies remain appropriate and reflect a CMU’s risk of non-delivery? If not, what alternative methodology could be applied and why? Please submit any evidence in support of your view.

[71] See Rule 2.3.8.

4. Long Term Considerations: Capacity Market Ten-year Review and Future Market Design

4.1 Context

The GB Capacity Market was implemented through four pieces of legislation which came into force over 2013 and 2014. These were:

- The Energy Act 2013 ('the Act');[72]
- The Electricity Capacity Regulations 2014 ('the Principal Regulations');[73]
- The Electricity Capacity (Supplier Payment etc.) Regulations 2014 ('the Supplier Payment Regulations');[74] and
- The Capacity Market Rules ('the Rules'),[75] which provide the detail on the operation of the Capacity Market.

The Act came into force in December 2013 and the secondary legislation (the Principal Regulations, the Supplier Payment Regulations, and the Rules) fully implemented the GB Capacity Market following State aid approval by the European Commission on 23 July 2014.

The Capacity Market has three core objectives:

- Security of supply: to incentivise sufficient investment in capacity to ensure security of electricity supply (linked to the set reliability standard);
- Cost-effectiveness: to ensure the most efficient level of capacity is secured at minimum cost to consumers; and
- Avoiding unintended consequences: to minimise design risks and complement the decarbonisation agenda.

The implementing legislation contains a requirement for the government to carry out five-yearly reviews of the Capacity Market to assess its suitability and effectiveness. The reviews must assess:

- Whether the objectives of the Capacity Market and its implementing legislation remain appropriate;

[72] See https://www.legislation.gov.uk/ukpga/2013/32/part/2/chapter/3/enacted.
[73] See https://www.legislation.gov.uk/uksi/2014/2043/contents/made for original version. The Regulations have been amended in 2015, 2016, 2017, 2019 and 2020.
[74] See https://www.legislation.gov.uk/uksi/2014/3354/contents/made.
[75] An informal consolidated version of the Rules is available here: https://www.gov.uk/government/publications/capacity-market-rules.

- The extent to which those objectives are being met; and
- Whether the objectives can be achieved in the future in a way that imposes less regulation.

As part of these requirements, we also assess whether the Capacity Market is still needed in the future to ensure security of supply, currently defined as a target of three hours Loss of Load Expectation (LOLE), and whether the Capacity Market remains the most suitable mechanism to achieve this.

A report summarising the first five-yearly review (the 'Five-year Review') of the Capacity Market scheme was published in July 2019.[76] Given that the Five-year Review process was initiated after the completion of only one full Capacity Market delivery year, the review was relatively light touch and aimed to identify forward-looking improvements rather than provide a full evaluation of past performance.

Following the Five-year Review, several high priority improvements were made in 2020 including the introduction of carbon emission limits, a reduction in the Minimum Capacity Threshold, and changes to better facilitate participation by DSR.

This Call for Evidence returns to some of the other issues identified through the Five-year Review, including reviewing agreement lengths for all technologies, strengthening the penalty regime, considering changes to secondary trading, reconsidering the potential benefits of split auctions, and considering direct participation of cross-border capacity.

4.2 Capacity Market Ten-year Review

4.2.1 Introduction

The Capacity Market was designed and implemented to address the market failures identified and persisting at a time when firm generators (usually fossil fuel derived) made up the majority of the fuel mix, with a relatively low but increasing penetration of non-firm generation.

Since the Capacity Market was implemented in 2014, the GB electricity system has undergone significant change. We expect that by the end of this decade, the electricity system will look significantly different to the present system. Most of GB's power supply will likely be derived from non-synchronous, intermittent renewable power, and interconnection from international electricity markets. This will need to be supplemented by flexible and dispatchable capacity, potentially only operating low load factors, that would provide power to ensure a stable power system and meet demand over periods of low renewable output.

In line with the statutory obligations stipulated in the Capacity Market's implementing legislation, we are now commencing the second five-yearly review (the 'Ten-year Review') process. We intend to review the Capacity Market to understand whether, in its

[76] Capacity Market: 5-year Review (2014 to 2019) – available here

current form, it can still address market failures in this evolving context and therefore ensure security of supply.

This project will be defined into two phases:

- Phase 1: Evaluation of historic performance
- Phase 2: Future Market Design.

4.2.2 Phase 1: Evaluation of historic performance (2014-2024)

As part of the Ten-year Review, we will be reviewing the Capacity Market's historic performance against its core objectives: security of supply; cost-effectiveness; and avoiding unintended consequences.

This evaluation will inform us to what extent the Capacity Market has achieved these objectives. It will also provide us with insight into how the different components of the Capacity Market (such as auction design, agreement management, auction parameter setting, penalty and termination regime, and the secondary trading framework) work in practice, and whether their design has driven efficient outcomes.

Furthermore, we will be using the review to assess the Capacity Market against the additional criterion of 'net zero compatibility'. This goes beyond the objective to 'avoid unintended consequences' and so will not be used to judge the historic performance of the Capacity Market. It will, however, act as an evidence base for our Future Market Design Workstream (see Phase 2 below), and help inform future decisions about the scheme design, including whether it is equipped to deal with the challenges posed by a system that is heavily reliant on intermittent renewables whilst also being consistent with our net zero ambition.

We intend to engage fully with stakeholders, following a similar process to that employed through the Five-year Review. We will conduct in-depth interviews and surveys with stakeholders to gain key insights into how the processes and mechanisms of the Capacity Market work and the impacts of the Capacity Market on their businesses, as well as internal modelling and analysis. The evaluation will consider process, impact, and value-for-money.

We welcome initial views and reflections from stakeholders on the Capacity Market's performance against its objectives. Any initial feedback gathered will be used to assist with scoping of the evaluation process and to guide our information-gathering on the Capacity Market's performance.

4.2.3 Phase 2: Future Market Design

There have been significant changes to the electricity mix since the introduction of the Capacity Market, from increased penetration of distributed capacity and renewables to the retirement of existing conventional generation. The electricity policy landscape has also evolved, with new ambitious net zero commitments and further support for low carbon technologies.

Renewable generation will dominate the electricity system to minimise emissions and costs. Firm low carbon generation (such as gas with carbon capture, utilisation and storage, hydrogen to power, and nuclear) and storage will be needed to balance variable renewables and changing demand profiles. Unabated gas may continue to play a role in the future system, although with lower load factors. Rising proportions of distributed generation as conventional transmission generation decreases pose further challenges to managing the system. A flexible electricity system, from both demand and supply sides, will be vital in a net zero scenario to enable the integration of increasing amounts of variable renewables.

Our working hypothesis is that there is a continued need for government intervention in the market, and the Capacity Market remains the most suitable way to deliver electricity security at least cost to the consumer whilst supporting decarbonisation targets. We do, however, intend to test this theory and remain open to alternatives.

We are, therefore, launching a review of the evolving security of supply needs of the electricity system and what this means for government intervention (in terms of the design of its policy mechanism to deliver security of supply). This is with a view to identifying any incompatibilities with wider policy ambitions and to bringing forward suitable change to ensure it fits within a changing market and system. We will also consider interactions between the Capacity Market and other policies, such as any future support for low carbon power.

The Capacity Market forms part of a wider market framework and its role in bringing forward new assets may have knock on impacts for other markets and policies. Ensuring that the Capacity Market is compatible with decarbonisation targets will require an examination of the interactions between the Capacity Market and other parts of the market, and we will engage with stakeholders on how best to do this as part of this workstream. This will work in parallel with any wider review of electricity markets and future reform.

To complete this phase, we have identified five steps and associated questions that we aim to address:

1. **Does the GB electricity market still require government intervention?**

   We are proceeding with a working assumption that government intervention will be required in future to ensure security of supply. The Five-Year Review of the Capacity Market, which was published just two years ago, concluded that the market fundamentals and failures which led to the introduction of the Capacity Market continued to persist and therefore there was a need to maintain the Capacity Market. Our expectation at this point is that some of the emerging market trends (e.g. firm capacity with lower load factors) may further strengthen the case for future intervention. We will, however, test this position and these assumptions as part of this review.

2. **Are the objectives of the CM still appropriate?**

Understanding whether the objectives remain appropriate is a statutory requirement of the Ten-Year Review of the Capacity Market. We will consider the evolving system needs (e.g. implications of a growing proportion of intermittent generation and new demand profiles) and what aspects need to be addressed to ensure security of supply and support our net zero decarbonisation targets. Our expectation is that the objectives will need to evolve and that we will need to demand more of capacity beyond simply delivering during system stress events, particularly with respect to supporting decarbonisation. This part of the review will require us to look at how the Capacity Market sits alongside and works with other interventions in the power market, including system services. As part of this step, we will also review our chosen reliability standard, including whether the three-hour LOLE target remains an appropriate metric.

3. **Is the CM the most appropriate tool to deliver the amended objectives?**

   This workstream will consider whether amendments to the existing Capacity Market are sufficient to meet any new objectives or whether a different mechanism may meet our future system needs better. For example, it may be suitable for a future mechanism to consider rewarding capacity providers for wider system benefits that they offer, such as flexibility (i.e. the ability to deviate from zero, or baseline, level of capacity in short time frames) and stability. Services like this will be important to the future security of electricity supply. We are keen to understand what role the chosen mechanism could play in ensuring adequacy (what the Capacity Market is currently designed to address) but also what it could do to assist NGESO with meeting operability challenges (such as stability. Again, our working hypothesis – to be tested through the review – is that a Capacity Market provides the most suitable mechanism for delivering electricity security at least cost to the consumer, albeit reforms to the current design will be necessary to support our decarbonisation ambitions.

4. **How should the future mechanism be designed?**

   The design of the future mechanism will depend on decisions from the first three questions around market failures, scheme objectives, and the chosen market mechanism. We will consider how to design the future mechanism so that so that it complements other elements of market.

5. **How can we ensure that we have a suitable institutional framework across the policy delivery partners?**

   Finally, we intend to review the functions and duties of the various organisations that are currently engaged in delivering the Capacity Market to ensure the efficient and effective management of the future energy security mechanism. We will review the performance and suitability of each organisation over the period of the Capacity Market's implementation and seek to understand whether this framework of policy delivery has provided the benefits that were intended, or whether the policy could be delivered in a more efficient way.

To help us progress this project, the government intends to form in 2022 an external Capacity Market 'Review and Design Committee' comprising representation from industry, stakeholder groups and market experts. We will engage with stakeholders over the coming months to identify suitable participants for this Committee before extending invitations later in 2021. We will be asking for expressions of interest to join such a group as well as any views on what stakeholder groups you would expect to be represented. In due course, we will consider the appropriate framework for publication of the Committee's work and its engagement with the wider stakeholder community via (for example) workshops, calls for evidence and consultations.

Summary of considerations put forward in Chapter 4

- As part of the Ten-year Review process, examine how the Capacity Market has met the additional criterion of 'net zero compatibility' alongside whether it has achieved its core objectives.

- Undertake a second phase of the review process (in parallel with the Ten-year Review) which will focus on the Capacity's Market's future role in meeting the evolving security of supply needs of the electricity system, including by establishing an external Capacity Market 'Review and Design Committee' comprising representation from industry, stakeholder groups and market experts.

Questions on considerations in Chapter 4

Question 29

Do you have initial views based on your experience on the Capacity Market's performance since its implementation that we should consider?

Question 30

What are your initial views on the Capacity Market as a continuing mechanism to address system adequacy? Is there a need for continued market intervention by the government to address electricity security? And could the Capacity Market (or an alternative electricity security mechanism) address wider system services such as flexibility and stability?

Question 31

Are there alternatives to the Capacity Market that may meet our current or future electricity security needs better, that we should consider? Please provide evidence to support your views.

5. Direct Cross-Border Participation

5.1 Context

Article 26 of the EU Electricity Regulation,[77] (part of the EU Clean Energy Package),[78] which applied on and from 1 January 2020, requires EU Member States to enable direct cross-border participation in capacity mechanisms. Implementing direct cross-border participation requires eligible capacity providers from a Member State to be allowed to participate in the capacity mechanism of other Member States, and vice versa. The rationale for this policy was to promote greater integration of the EU internal energy market (IEM) and more competition in capacity mechanisms, with the aim of achieving lower auction clearing prices and ultimately securing lower costs for EU consumers.

The European Commission's decision[79] of 24 October 2019, which granted State aid approval for the Capacity Market, noted the UK's commitment to implement six improvements to the Capacity Market's design, including endeavouring to implement arrangements to enable direct cross-border participation. Most of the six commitments were implemented in 2020 through the Future Improvements consultation.[80]

In that same consultation, we noted that the implementation of direct cross-border participation raised significant design challenges. Consequently, further stakeholder engagement would be needed before bringing forward a consultation on amendments to the Capacity Market Rules and Principal Regulations to implement direct cross-border participation.

The UK's commitment to enable direct cross-border participation was conditional on a number of arrangements at EU level being completed and becoming applicable - notably, the EU methodologies and common rules, as well as the multilateral arrangements set out in Article 26(11).

5.2 Recent developments

Since the European Commission's State aid decision in 2019, the UK has left the European Union. During the Transition Period, the UK co-operated with EU institutions and EU Member States to progress the development of the European Network of Transmission System Operators for Electricity (ENTSO-E) methodologies required under Article 26(11) of the EU Electricity Regulation. However, the end of the Transition Period, the UK's exit from the IEM, and the UK's new status as a non-EU state represent a fundamental shift in the legal basis and

77 https://eur-lex.europa.eu/legal-content/EN/TXT/PDF/?uri=CELEX:32019R0943&from=EN#:~:text=(26)%20A%20precondition%20for%20effective,lines%20in%20the%20transmission%20system
78 https://ec.europa.eu/energy/topics/energy-strategy/clean-energy-all-europeans_en
79 https://ec.europa.eu/commission/presscorner/detail/en/ip_19_6152
80 https://www.gov.uk/government/consultations/capacity-market-proposals-for-future-improvements

the applicable framework for implementing future direct cross-border participation with EU Member States.

Following the end of the Transition Period on the 31 December 2020, Article 26 has been revoked from domestic retained EU law, so it is no longer part of domestic law in Great Britain.[81] Implementing direct cross-border participation in accordance with Article 26 of the EU Electricity Regulation rests on the assumption of EU membership and the establishment of reciprocal arrangements with the EU. The Trade and Cooperation Agreement (TCA) between the UK and the EU,[82] which became applicable on 1 January 2021, contains the following confirmation on direct cross-border participation: Article 304(3) 'Neither Party is required to permit capacity situated in the territory of the other Party to participate in any capacity mechanism in its electricity markets'.[83]

5.3 Implications for direct cross-border participation in the Capacity Market

There are several significant challenges with opening the Capacity Market to the direct participation of capacity located in the EU at this time. It is clear that, under the model set out in Article 26(1) of the EU Electricity Regulation, and the ENTSO-E methodologies,[84] a number of arrangements that will enable direct cross-border participation have not yet occurred within the EU.

Equally, Article 26 and the methodologies clearly require the arrangements for cross-border participation to be reciprocated between Member States, the relevant Transmission System Operators (TSOs), and capacity mechanism operators. Now that the UK has left the EU, these reciprocal arrangements would need to be extended to the UK as a non-EU state. Additionally, any necessary bilateral arrangements would also need to be formally agreed with the EU.

Consequently, it is not possible for the UK to implement direct cross-border participation in the Capacity Market at this time. We remain open to considering the implementation of direct cross-border participation in the Capacity Market at a future stage, to a longer timeframe. In the near term this means we will continue to allow interconnector participation in the Capacity Market. However, now that we have left the EU and the IEM, we have the opportunity to consider the range of policy options available to us to determine how cross-border flows are accounted for within the Capacity Market.

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[81] See Regulation 7 and paragraph 25 to Schedule 4 of the Electricity and Gas (Internal Market and Network Codes) (Amendment etc.) (EU Exit) Regulations 2020 (https://www.legislation.gov.uk/ukdsi/2020/9780348209495/contents) which fixed inoperabilities in retained EU law arising as result of EU Exit

[82] The TCA was agreed on 24 December 2020: https://www.gov.uk/government/publications/agreements-reached-between-the-united-kingdom-of-great-britain-and-northern-ireland-and-the-european-union

[83] https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/982648/TS_8.2021_UK_EU_EAEC_Trade_and_Cooperation_Agreement.pdf

[84] https://www.acer.europa.eu/Official_documents/Acts_of_the_Agency/Individual%20decisions/ACER%20Decision%2036-2020%20on%20cross-border%20participation_XBP%20CM.pdf

Cross-border participation in capacity mechanisms can broadly be enabled in two ways: either through allowing the participation of interconnectors in a capacity mechanism (indirect cross-border participation); or by allowing eligible, non-domestic capacity providers to directly participate in a domestic capacity mechanism (direct cross-border participation). To calculate the correct target capacity for Capacity Market auctions, cross-border flows need to be accounted for. Broadly this can be done in two ways. Firstly, if cross-border participation is not allowed in a capacity mechanism, the expected contribution of cross-border flows to security of supply can be subtracted from the target capacity. Alternatively, where cross-border participation is allowed, the expected contribution of cross-border flows to security of supply is included in the target capacity.

The first Capacity Market auction in 2014 did not allow cross-border participation. In 2015 we introduced the participation of interconnectors to the Capacity Market to ensure that incentives for additional investment were not distorted in favour of GB generation, potentially at the expense of interconnection to European markets which may be more cost-efficient. However, this was intended as a temporary measure until the necessary framework was in place to allow non-domestic capacity providers to participate in the Capacity Market. Responses to the Capacity Market Five-year Review raised concerns about both the reliability of interconnectors and their contribution to security of supply, and the potential fairness of interconnector participation due to possible market distortions arising in the wider policy landscape (e.g. interconnector access to the cap and floor regime, exemption from the Transmission Network Use of System (TNUoS) and Balancing Services Use of System (BSUoS) charges, and ability to participate in multiple capacity mechanisms).[85]

Given the altered context the UK is now operating in following EU Exit, it is appropriate to consider if cross-border participation remains appropriate for the Capacity Market in any form – either through implementing direct cross-border participation or the current interconnector model. Alternatively, cross-border flows could be accounted for when assessing capacity adequacy, with the calculations for the target capacity for the auctions modified to exclude the expected contribution of cross-border flows to security of supply.

Should we decide to continue with the cross-border participation approach, it is important to consider which approach is most suitable for the Capacity Market. It may be that moving away from the current model of interconnector participation to direct cross-border participation is appropriate in time. This is assuming that the practical challenges of implementing such a model can be overcome, and that it is best placed to contribute to the Capacity Market's objective of providing security of electricity supply at least cost to consumers.

We welcome views on the future of cross-border participation in the GB Capacity Market, including the rationale, and any alternative solutions.

Summary of considerations put forward in Chapter 5

[85] https://www.gov.uk/government/publications/capacity-market-5-year-review-2014-to-2019

- Explore the range of available policy options on cross-border participation in Capacity Market, including options for allowing the participation of interconnectors in a capacity mechanism (indirect cross-border participation), for allowing eligible, non-domestic capacity providers to directly participate in a domestic capacity mechanism (direct cross-border participation), or for ceasing to enable cross-border participation in the Capacity Market.

Questions on considerations in Chapter 5

Question 32

Should we continue to enable cross-border participation in the Capacity Market? If not, why not? In the absence of cross-border participation, how should target capacity calculations be altered to reflect the contribution of cross-border flows to security of supply?

Question 33

If the CM continues to enable cross-border participation, what should be the preferred approach to cross-border flows – enabling direct participation of foreign generation, or continue with the existing indirect cross-border participation model (via interconnectors)? Please provide evidence to support your views.

6. Recap of questions in this Call for Evidence

Questions on Chapter 2

Question 1

Could ‘low carbon capacity’ in the context of the Capacity Market be defined in terms of an emissions limit? If so, what should form the basis of this limit – for example, would it be better to base a limit on carbon intensity or overall annual emissions, and what types of capacity should be captured by this emissions limit?

Question 2

Are there alternative approaches to defining low carbon capacity in the context of the Capacity Market? Please provide justifications.

Question 3

What are your views on the benefits or challenges of linking future long-term Capacity Market agreements to a new carbon emissions limit? Do you have any suggestions regarding an appropriate approach to setting such an emissions limit, and how could we best account for ‘lower’ rather than ‘low’ carbon technologies in determining eligibility for multi-year agreements?

Question 4

Is it necessary and appropriate for carbon intensive generation to continue to access shorter multi-year agreements, until such a time as low carbon dispatchable generation is more widely available?

Question 5

Would you expect these suggested changes to agreement lengths to affect your decision to participate in the Capacity Market, your bidding behaviour, or the costs of and access to finance? If so, how? Can you suggest any alternative approaches to ensuring agreement lengths offered in the Capacity Market are consistent with the delivery of net zero targets?

Question 6

Is it still appropriate to maintain the link between capital expenditure thresholds and multi-year agreements? If not, what other criteria could we consider using to assess eligibility for multi-year agreements (other than the new lower emissions limit discussed in section 2.3.2.1)?

Question 7

Should we revise the applicable capital expenditure thresholds? If so, what data could we base them on, and do we still need to have two different thresholds? Should low carbon DSR be able to access shorter multi-year agreements on the basis of emissions limits rather than capital expenditure thresholds?

Question 8

Should we review the 77 month window for new builds?

Question 9

What are the benefits of maintaining the Extended Years Criteria?

Question 10

What are your views on the introduction of a declared later delivery year as a way of addressing the challenges experienced by projects with long build times seeking to enter the Capacity Market? Would this affect your decision to participate in the Capacity Market, and if so, how? Are there other approaches we could take to removing barriers to participation for technologies and projects with long build times?

Question 11

Do you agree with our suggested approach to determining and verifying eligibility for a declared later delivery year? Are there other approaches we could consider?

Question 12

How can we best mitigate any security of supply risks arising from this approach? Can you identify any additional risks and/or disbenefits related to the introduction of a declared later delivery year?

Question 13

What are your views on the benefits and challenges of introducing an auction design splitting auctions between new build and refurbishing low carbon capacity and existing capacity? Would this affect your decision to participate in the Capacity Market or your bidding behaviour, and if so, how?

Question 14

What are your views on the potential split auction designs considered in sections 2.5.2 and 2.5.3? Are there alternative designs we should consider? And what approach could we take to setting targets for a separate low carbon auction?

Question 15

What are your views on expanding the scope of the Price Taker Threshold to potentially make it a price cap for Price Taker Capacity? Would this impact bidding behaviour? What changes to the Price Maker Memorandum might be necessary to ensure any changes to the Price Taker Threshold would be effective?

Question 16

What are your views on the potential benefits or challenges of amending the Net Welfare Algorithm to calculate to next lowest bid, rather than by the round floor price? Would this have an impact on bidding behaviour?

Question 17

How might the changes to auction design considered in section 2.5 interact with other design possibilities explored in Chapter Two concerning agreement lengths (2.3) and projects with long build times (2.4)?

Questions on Chapter 3

Question 18

What are your views on changing the figure used in calculating the penalty rate (for example, from 1/24 to 1/8 or 1/4)? Should the penalty rate be linked to the Value of Lost Load rather than the auction clearing price? Please provide supporting reasons/evidence.

Question 19

What are you views on the changes we consider in relation to the annual and monthly penalty caps?

Question 20

What are you views on the options we consider for improving the coordination of capacity during a stress event?

Question 21

Do you agree with the idea of introducing an additional Satisfactory Performance Day for CMUs that fail to deliver in a stress event?

Question 22

What are your views on the options we set out regarding the recovery of unpaid penalties?

Question 23

Would you expect any of these changes to the penalty regime to affect your decision to participate in the Capacity Market, your bidding behaviour, or the costs of and access to finance, and, if so, how?

Question 24

What are you views on the benefits and challenges of the alternative model for a penalty regime set out in section 3.1.5? Are there other models we should consider?

Question 25

What are your views on appropriate testing arrangements for wind and solar CMUs, distribution connected CMUs, and co-located CMUs?

Question 26

Which is your preferred option of those proposed in section 3.2.5 relating to the timing of the connection capacity test? Are there alternative approaches we could consider?

Question 27

Would it be beneficial for us to enable a third party (such as the Delivery Body) to re-auction capacity obligations in respect of CMUs that have been terminated during the delivery year, or between a capacity auction and the start of the relevant delivery year? If so, what are your views on the principles for such an arrangement (set out in section 3.3.2), and do you have any commercial considerations and/or concerns about the use of a third-party facilitator?

Question 28

In your view, do the current de-rating methodologies remain appropriate and reflect a CMU's risk of non-delivery? If not, what alternative methodology could be applied and why? Please submit any evidence in support of your view.

Questions on Chapter 4

Question 29

Do you have initial views based on your experience on the Capacity Market's performance since its implementation that we should consider?

Question 30

What are your initial views on the Capacity Market as a continuing mechanism to address system adequacy? Is there a need for continued market intervention by the government to address electricity security? And should the Capacity Market (or alternative electricity security mechanism) also address wider system services such as flexibility and stability?

Question 31

Are there alternatives to the Capacity Market that may meet our current or future electricity security needs better, that we should consider? Please provide evidence to support your views.

Questions on Chapter 5

Question 32

Should we continue to enable cross-border participation in the Capacity Market? If not, why not? In the absence of cross-border participation, how should target capacity calculations be altered to reflect the contribution of cross-border flows to security of supply?

Question 33

If the CM continues to enable cross-border participation, what should be the preferred approach to cross-border flows – enabling direct participation of foreign generation, or continue with the existing indirect cross-border participation model (via interconnectors)? Please provide evidence to support your views.

This publication is available from: www.gov.uk/government/consultations/capacity-market-2021-call-for-evidence-on-early-action-to-align-with-net-zero