UK Government

Capacity Market

Call for evidence on Hydrogen to Power and interconnectors

Closing date: 27 November 2025

October 2025

Any enquiries regarding this publication should be sent to us at:
futureelectricitysecurity@energysecurity.gov.uk.

Contents

1. General information

1.1 Why we are calling for evidence

The security of our electricity supply is key to the successful delivery of the Clean Energy Superpower Mission and one of its key pillars - clean power by 2030. In this call for evidence, the government is seeking views on how to categorise Hydrogen to Power to inform potential changes to the Capacity Market to enable participation. The government is also seeking views on a new approach for determining the technical reliability of interconnectors for the purpose of setting their de-rating factors.

1.2 Call for evidence details

Issued: 2 October

Respond by: 27 November

Enquiries to:

Department for Energy Security and Net Zero

3-8 Whitehall Place

London

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Email: futureelectricitysecurity@energysecurity.gov.uk

Consultation reference: Capacity Market: Call for evidence on Hydrogen to Power and interconnectors

Audiences: We are seeking the views of the energy industry, consumer groups, academia, think tanks and other organisations who have an interest in security of supply and decarbonisation.

Territorial extent: Great Britain. The Capacity Market is in place across Great Britain. Energy is a devolved matter for Northern Ireland.

1.3 How to respond

We strongly encourage respondents to make use of the online platform wherever possible when submitting responses as this is the government's preferred method. This method also allows you to submit a single, combined response to both this call for evidence and the Capacity Market consultation which has been published simultaneously, should you wish to respond to both. Alternatively, responses in writing or via email will also be accepted.

When responding, please state whether you are responding as an individual or representing the views of an organisation.

Your response will be most useful if it is framed in direct response to the questions posed, though further comments and evidence are also welcome.

Respond online at: https://energygovuk.citizenspace.com/energy-security/capacity-market-hydrogen-to-power-interconnectors

1.4 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, 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.

Your personal data may be shared with our processor for the purposes of analysing the consultation responses on our behalf. Artificial Intelligence (AI) may be used in the analysis of consultation responses.

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

We will summarise all responses and publish this summary on GOV.UK. The summary will include a list of names or organisations that responded, but not people's personal names, addresses or other contact details.

1.5 Quality assurance

If you have any complaints about the way this call for evidence has been conducted, please email: bru@energysecurity.gov.uk.

2. Executive summary

The security of our electricity supply is vital to successfully achieving the Prime Minister's Clean Energy Superpower Mission and its key pillars of providing clean power by 2030 and accelerating the delivery of net zero by 2050.

The Capacity Market (CM) is at the heart of the government's strategy for ensuring security of electricity supply in Great Britain. It was first introduced in 2014 as part of the Electricity Market Reform programme to support investment in capacity and deliver value for money for consumers.

Existing and new build electricity capacity providers compete to obtain Capacity Market Agreements under which they commit to deliver capacity when needed, in return for guaranteed payments. This capacity, categorised by Generating Technology Classes (GTCs), can be in the form of generation, interconnectors, consumer-led flexibility, and energy storage. The scheme is technology-neutral, but capacity is "de-rated" based on the expected reliability of each technology type during periods of system stress.

As set out in the Clean Power Action Plan,[1] whilst the electricity system of Great Britain will continue to rely on unabated gas to ensure security of supply, the government is supporting the deployment of low carbon long duration flexible technologies, such as Hydrogen to Power (H2P), that are capable of replicating the role of unabated gas.

To deliver H2P deployment, the government committed in December 2024[2] to implement a Hydrogen to Power business model (H2PBM) which will be launched in 2026. The government expects the H2PBM to be the main route to market for H2P plants, but some H2P plants could come forward through the CM initially, with this rising as the technology develops and deployment barriers fall away. As outlined in the December 2024 consultation response announcing the H2PBM, the government expects the CM to be the enduring support mechanism for H2P deployment. The government is committed to enabling the participation of H2P in the CM as soon as practical, and this call for evidence is the first step in that process.

In addition to H2P, electricity interconnectors can bring a wide range of system and consumer benefits, supporting security of supply by enabling access to more diverse generation over a wider geographic area.

The Capacity Market Rules (the Rules), which set out the requirements on its participants, are regularly reviewed. This is to ensure the scheme remains fit for purpose and reflects changing market conditions. To support future policy development and inform how these technologies should be treated in the CM, the government is publishing this call for evidence to:

- Gather evidence to inform how H2P plants should be categorised within the CM to enable the participation of H2P as a new technology. This includes gathering evidence related to the operation and reliability of H2P plants.

- Test stakeholder views on implementing a new methodology for the technical adjustment element of the process by which interconnector de-rating factors are set,

[1] DESNZ, Clean Power Action Plan, December 2024.
[2] DESNZ, Hydrogen to power: market intervention need and design, December 2023.

including exploring how high-impact low-probability events should be treated within the methodology.

This call for evidence is in addition to a consultation, which has been published alongside this document.[3] The proposals in the consultation aim to reform the CM to improve security of supply and functionality of the scheme whilst aligning the CM with the government's clean power mission and long-term net zero goals.

3. Introduction

Since its introduction in 2014, the Capacity Market (CM) has secured sufficient capacity to achieve its principal function, ensuring consistent and reliable electricity supply. A reliable electricity system is fundamental for a well-functioning society, economy and public services. It has a positive effect on investment for industrial and commercial sectors. Blackouts have severe economic consequences, as companies depend on a reliable electricity system to provide goods and services. Security of supply will become more important to the functioning of the economy while power systems are decarbonised, and demand increases significantly due to the electrification of our heat and transport systems.

As the electricity system of Great Britain transitions to clean power, it is crucial we complement renewables with flexible capacity to ensure we can deliver clean power no matter the weather. Historically, unabated fossil fuels have provided this flexibility, but that leaves us exposed to the rollercoaster of fossil fuel prices. The Clean Power Action Plan[4] sets out a pathway towards deploying low carbon flexible capacity technologies, such as Hydrogen to Power (H2P), working alongside technologies such as nuclear generation, which provide round the clock reliable power.

In September 2024, the government published its annual open letter inviting views as to whether any new generating technologies, which could contribute to security of supply and which are not already identified as a GTC should be eligible to participate in future CM auctions.[5] Stakeholders highlighted H2P as a technology that the government should seek to enable in the CM in future.

In December 2024, the government responded to the consultation on the need for a market intervention to enable the deployment of H2P[6] which committed to introduce a new H2P business model (H2PBM). Alongside this, the government also committed to enabling H2P to participate in the CM as soon as practical. The government expects the H2PBM to be the main route to market for H2P plants, but some H2P plants could come forward through the CM initially, with this number rising as the technology develops and deployment barriers fall away. As outlined in the December 2024 consultation response announcing the H2PBM, the government expects the CM to be the enduring support mechanism for H2P deployment in the long term. This call for evidence (CfE) is a first step to exploring the technical feasibilities of enabling participation of H2P in the CM.

[3] DESNZ, Capacity Market: proposed changes for Prequalification 2026, October 2025.
[4] DESNZ, Clean Power Action Plan, December 2024.
[5] DESNZ, Open letter on new technologies in the Capacity Market, 2024: government response, November 2024.
[6] DESNZ, Hydrogen to power: market intervention need and design, December 2023.

The government is seeking to understand how different types of H2P plants, including blended[7] plants, should be categorised within the CM. This includes testing which Generating Technology Classes and associated de-rating factors would be most applicable to the different possible configurations of H2P plants. The exploratory questions and discussion set out in this document should not be considered to reflect any finalised decision on H2PBM design.

Electricity interconnectors connect the transmission systems of two countries, enabling the import and export electricity. Electricity interconnectors support security of supply by enabling access to more diverse generation over a wider geographic area. They also provide system flexibility by helping the system rapidly respond to changes in supply and demand. This means that, when we generate more electricity than we need, a strong interconnector system will allow us to export the excess electricity, thus contributing towards the Clean Energy Superpower Mission.

This CfE is exploring targeted improvements to the technical de-rating process for interconnectors, to ensure that the technical assessment approach undertaken by the government remains up to date and fit for purpose. This provides an opportunity for greater transparency around the methodology that the government applies to reflect a technical reliability adjustment in the final step of setting interconnector de-rating factors. As such, the government commissioned Frontier Economics and LCP Delta to provide updated approaches to consider technical reliability which could be applied when determining interconnector de-rating factors. The report from Frontier Economics and LCP Delta which details these approaches has been published alongside this CfE.[8]

This CfE will build an evidence base to support decision making on enabling H2P to participate in the CM and improve the de-rating methodology for interconnectors. Future proposals to make changes to the CM may be subject to consultation.

[7] H2P plants burning a mixture of hydrogen and natural gas fuel with the fuel mixed on site.
[8] DESNZ, Technical Derating factors for electricity interconnectors, October 2025

4. Participation of Hydrogen to Power

4.1 Context

The Clean Power Action Plan set out the government's commitment to deploying Hydrogen to Power (H2P) as a key technology for providing long duration and dispatchable capacity to the electricity system.[9] H2P can play a key role in our electricity system at a range of scales, provide a decarbonisation pathway for unabated gas generation, and when connected to large-scale hydrogen storage, can enable inter-seasonal low carbon electricity storage.

In December 2024, the government committed to implement a H2P business model (H2PBM) to drive investment and mitigate deployment barriers specific to H2P projects. The 2025 Spending Review[10] confirmed over £500m to establish the UK's first regional hydrogen network from 2031. This will connect hydrogen producers with vital end users, such as power and industry – unlocking hydrogen's role in clean power. In the June 2025 Industrial Strategy[11] it was announced the H2PBM will be launched from 2026, and the first hydrogen storage and transport business model allocation rounds will also be launched next year.

H2P and its associated enabling hydrogen infrastructure (production, transport and storage) are emerging technologies. The evidence gathered through this CfE will be valuable to informing how H2P can participate in the CM and in supporting wider H2P and hydrogen policy development. Any future proposals to enable the participation of H2P in the CM will be subject to consultation.

4.2 Categorising Hydrogen to Power

Within the CM, plants are categorised by Generating Technology Class (GTC), with each GTC having its own de-rating factor (DRF) which is a reliability-based adjustment that reduces a unit's nominal capacity to reflect its expected availability during peak system stress. To become eligible to participate in the CM, new technologies are identified by a GTC. Currently there are no bespoke GTCs for H2P in the CM.

The government is aware that the term "H2P" can cover a range of plants that have different configurations and therefore require different considerations for how they are categorised within the CM. These different configurations could include combustion plants that are more typical to existing gas plants or could utilise hydrogen fuel cells to generate electricity. The combustion plants may run fully on hydrogen or be fuelled by onsite blending of hydrogen and natural gas at differing volumes which may change or be a static volume.[12] In sections 4.3 and

[9] DESNZ, Clean Power Action Plan, December 2024.
[10] DESNZ, £500m boost for hydrogen to create thousands of British jobs - GOV.UK, June 2025.
[11] DESNZ, Industrial Strategy: Clean Energy Industries Sector Plan, June 2025.
[12] On site blending of hydrogen is separate to the government's work assessing the case for transmission blending, which is focused on proposals to blend hydrogen into the existing GB gas networks and the strategic and economic role this could play. Government consulted on these proposals in July 2025: Hydrogen blending into the GB gas transmission network - GOV.UK

4.4, further consideration is set out on how these different technologies could be treated for the purpose of CM categorisation.

This CfE considers options for utilising existing GTCs or establishing bespoke GTCs for each of the different configurations of H2P plants and is seeking evidence to inform decision making on the best way to accommodate H2P in the CM while maintaining security of supply.

Hydrogen combustion plants

H2P combustion plants could have different operating profiles due to varying commercial and technical characteristics. This could also include plants that that blend hydrogen and natural gas onsite.

Plants connected to the wider hydrogen network:

Subject to the availability of a sufficient hydrogen fuel supply and enabling infrastructure, the government expects that H2P plants will utilise a wider hydrogen network, where plants would access hydrogen transported from producers, likely via storage, to where it would be used for power generation, enabling the plant to operate fully on hydrogen.

In the early stages of deployment, some H2P plants may use natural gas to start-up power generation, however, we anticipate technologies which can operate entirely on hydrogen will develop, limiting the need for H2P plants to require a natural gas connection[13].

Closed loop systems:

H2P plants may also deploy as closed loop systems. This could comprise hydrogen production and storage operating onsite, or be virtually integrated, alongside power generation units. The government expects these systems could be less exposed to the types of cross-chain risk associated with the wider hydrogen network as the supply of hydrogen is within the control of the H2P plant. The generation potential of plants on a closed loop system may be limited by onsite storage capacity (or potentially other factors, such as power availability to produce hydrogen). At the same time, these plants could choose to have a natural gas connection which could provide a back-up fuel supply function. A range of technical and commercial characteristics could influence how this type of H2P configuration could support security of supply.

A plant’s ability to generate hydrogen on site as part of a closed loop system, their connection to a wider hydrogen network, as well as any connections to the natural gas network, should be considered as part of the different potential categorisations of H2P.

Onsite blending H2P plants:

Stakeholders have expressed interest in blending hydrogen as part of their fuel mix. This includes new build plants and plants which have previously run primarily on natural gas and already have CM agreements. Considering currently available technology and the age of retrofitting sites, onsite blending plants are likely to face technical limits on the volume of hydrogen they can use, which may prevent them from reaching 100% hydrogen-firing capability. Some plants may blend hydrogen consistently at a low level, whilst others will start at a lower level and gradually increase their hydrogen levels over time.

[13] Based on feedback from the government’s engagement with Original Equipment Manufacturers.

Fuel Cells

Hydrogen fuel cells could be a viable grid-scale H2P technology in the future. A fuel cell is an electrochemical device that converts chemical energy directly into Direct Current electricity by consuming fuel from an external source.[14] Hydrogen fuel cells could have different configurations to combustion plants and the government welcomes feedback on how fuel cells could be categorised in the CM.

4.3 Utilising existing Generating Technology Classes

The CM does not define the meaning of gas or determine which gas plants should use for power generation, although traditionally combustion plants use natural gas. The Gas Act 1986 (Gas Act) cites hydrogen under the definition of "gas" as a type of substance in a gaseous state alongside other gas forms used for power generation, such as methane. Given the technical characteristics of combustion, H2P plants will not be significantly different from a typical natural gas plant. Therefore, the government is seeking industry views on whether early H2P projects could participate in the CM under one of the existing gas GTCs (Table 1).

H2P is a first of a kind technology and there will be limited projects sufficiently developed to enter the CM, resulting in low volumes entering auctions initially, thereby limiting the initial impact they have on security of supply. Once H2P plants have been operational within the CM for a few years, a bespoke GTC and DRF could be developed if required. This approach has been taken in the past with large scale biomass, which was initially grouped with coal and later given a bespoke GTC and DRF once more evidence was available for how it performed.

Table 1: Gas Generating Technology Classes (GTC) in the Capacity Market. [15]

Gas GTC	Description	De-rating factor
Open Cycle Gas Turbines (OCGT)	Air is compressed, mixed with fuel and burned in a combustion chamber which generates hot, high-pressure gas which is passed through a turbine extracting mechanical energy to drive an electrical generator.	93.49%
Combined Cycle Gas Turbines (CCGT)	The same as an OCGT with an additional 'bottoming cycle' which recovers the waste heat from the exhaust gases through a Heat Recovery Steam Generator to convert water into steam which drives a further turbine.	90.95%
Combined Heat and Power (CHP)	Waste heat from the process used for heating. This is more typical of smaller power plants located where heat is needed and can be combined with gas turbine cycles or gas reciprocating engine cycles.	90.95%
Gas reciprocating engines	Uses the expansion of heated gas to drive the linear motion of reciprocating pistons, which are converted to rotational motion via a crank shaft.	93.49%

[14] DESNZ, UK Strategic Export Control List
[15] National Energy System Operator, Capacity Market Auction Guidelines, February 2025.

The current gas GTC as outlined in Table 1 does not include technologies which are directly comparable to a hydrogen fuel cell. The government therefore expects that a new GTC would be required for hydrogen fuel cells. This is discussed more in Section 4.4.

Plants with a natural gas connection

H2P plants with a natural gas connection may be capable of using both natural gas and hydrogen[16] – this could mean running on hydrogen as their main fuel and then switching to natural gas if, for example, they experience issues with their hydrogen supply. Beyond operational reliability, for which there is currently no historical data, this capability and a connection to the natural gas network could be the deciding factor for whether H2P can be classed under the existing gas GTCs. This is because it may be considered that access to a natural gas connection is an alternative fuel supply, allowing the plant to operate akin to an unabated gas plant, where it would be connected to a mature reliable natural gas network.

Therefore, in lieu of historical operational data for H2P plants, the CM could classify these H2P plants under the existing gas GTCs. The government is seeking to test this assumption and if introduced, it would expect to keep such a classification under review as more operational evidence becomes available.

Onsite blending H2P plants:

The government recognises that the level of onsite hydrogen blending best suited to a particular plant could be dependent on a variety of factors such as the plant size, age, configuration, location and access to hydrogen transport and storage (T&S) infrastructure. Where applicable, respondents to the CfE should consider the plants described in Table 1, which correspond to the gas GTCs when developing responses.

Based on the interpretation of the Gas Act, both existing and new build gas capacity may seek to blend hydrogen as part of their typical natural gas fuel mix and the government is seeking to understand whether the co-firing of natural gas and hydrogen would lead to any material differences in the reliability of the gas plant. As the CM's primary function is a security of supply mechanism, the government will need confidence that gas plants can still deliver on their CM obligations as they begin introducing hydrogen into their fuel mix. This includes considering potential outages during technical modifications required for existing generating units to blend hydrogen, as well as the plants' ability to ramp up generation to meet their obligations. If the government concludes that the reliability of the plant is impacted by onsite hydrogen blending, a decision will need to be made about the need for a potential new GTC and de-rating factor for blended plants. However, as the plant will have a natural gas connection, the government's working assumption is that the plant would switch back to full natural gas operations in times of system stress or if there were issues to the hydrogen supply.

Ahead of consulting on any potential rule changes required to enable gas plants to blend hydrogen as part of their fuel mix, the government is seeking to test stakeholder views that the same GTC would apply to these plants and whether there would be any unforeseen consequences regarding security of supply.

[16] This is based on feedback on the H2P Government Response and further discussions with Original Equipment Manufacturers.

Plants without a natural gas connection

The government would like to explore how to classify H2P plants which are not connected to the natural gas network. Although these plants could also technically come under the existing gas GTCs by virtue of how gas is defined, their exposure to a nascent hydrogen network and/or onsite storage (which is likely to be small-scale), could make the existing gas DRFs, which are predicated on the mature and reliable natural gas network, inappropriate for these plants.

The government is seeking to explore whether H2P plants connected to a wider hydrogen network, but without a natural gas connection would require a new GTC.

The government is also considering whether a storage GTC would be appropriate for H2P plants which are not connected to the natural gas network or wider hydrogen network and could be potentially considered duration-limited in circumstances where the plant's dedicated hydrogen fuel supply is limited. There are a number of storage GTCs in the CM, where the DRF is set according to the maximum duration of electricity export when the storage is at full capacity. Each half hourly increment of duration has its own GTC and DRF, going from 0.5 hours to 9.5+ hours (Table 2). [17]

The GTC and DRF applied could be based on the duration of output the hydrogen storage enables, as is the case for other storage technologies. However, consideration would need to be given to whether the specific attributes of onsite hydrogen production and storage (e.g. refill time) make it inappropriate to apply the same storage DRFs used for other existing storage technologies.[18]

[17] National Energy System Operator, Capacity Market Auction Guidelines, February 2025.
[18] De-rating factors are published ahead of each auction pre-qualification by the National Energy System Operator: Capacity Market Auction Guidelines, February 2025.

Table 2: Storage Generating Technology Classes in the Capacity Market. [19]

Storage GTC Description	Storage duration (hours)	De-rating factor
Conversion of imported electricity into a form of energy which can be stored, storing the energy which has been so converted and the re-conversion of the stored energy into electrical energy Includes hydro Generating Units which form part of a Storage Facility (pumped storage hydro stations).	0.5	5.30%
	1	10.47%
	1.5	15.77%
	2	20.94%
	2.5	26.10%
	3	31.27%
	3.5	36.57%
	4	41.47%
	4.5	47.04%
	5	52.34%
	5.5	57.51%
	6	62.67%
	6.5	67.84%
	7	73.14%
	7.5	78.31%
	8	83.47%
	8.5	88.78%
	9	92.99%
	9.5+	92.99%

[19] National Energy System Operator, Capacity Market Auction Guidelines, February 2025.

4.4 Establishing new Generating Technology Classes

The government is aware it may not be appropriate to enable first-of-a-kind combustion H2P plants through existing GTCs and would therefore like to seek views from stakeholders on which factors would need to be considered when developing a bespoke GTC and de-rating factor for these plants.

New GTCs may be required for H2P plants that do not have a connection to the existing natural gas network or onsite storage. These plants instead will rely on a wider hydrogen network which is likely to be less mature than the natural gas network in the short to medium term.

Hydrogen fuel cells could be a viable grid scale H2P technology in the future. If hydrogen fuel cells were to participate in the CM, a new GTC would likely be required as hydrogen fuel cells do not meet the existing technology definitions within the gas GTC as the technology is fundamentally different to combustion technologies.

Questions1-6 are related to enabling the participation of H2P in the CM. Questions 7-12 are focused on projects considering onsite blending. For all questions, please provide evidence to support your views and make clear what kind of H2P technology configuration(s) your response relates to.

Question 1: What are your views on Hydrogen to Power combustion plants connected to the wider hydrogen network and with natural gas connections participating in the Capacity Market under the existing gas Generating Technology Classes with the associated de-rating factors?

Question 2: What are your views on Hydrogen to Power combustion plants connected to the wider hydrogen network and without natural gas connections participating in the Capacity Market under the existing gas Generating Technology Classes with the associated de-rating factors?

Question 3: What are your views on Hydrogen to Power combustion plants without access to natural gas, but with onsite storage, being categorised as duration limited and therefore participating in the Capacity Market under a Storage Generating Technology Class with the associated de-rating factors?

Question 4: If the government was to implement bespoke Generating Technology Class(es) for Hydrogen to Power plants, what factors would need to be considered when developing the de-rating factor? Please consider both combustion plants and fuel cells.

Question 5: What wider factors (beyond Generating Technology Class(es) and de-rating factors) need to be considered to enable Hydrogen to Power to participate in the Capacity Market?

Question 6: Are there any unintended consequences that could occur from enabling Hydrogen to Power to participate in the Capacity Market?

Question 7: If you are an operator of an existing gas Capacity Market Unit, are you considering onsite blending of hydrogen and natural gas for power generation? Is the current Capacity Market framework sufficient to enable blending?

Question 8: Would the opportunity to blend hydrogen as part of your fuel mix incentivise you to bring forward new or invest in the lifetime extension of existing unabated gas capacity?

Question 9: What are your views on how the government should approach Generating Technology Classes for hydrogen and natural gas blended fuel plants, including whether existing Generating Technology Classes are appropriate?

Question 10: Are there any unintended consequences that could occur from enabling natural gas plants to blend hydrogen in their fuel mix?

Question 11: What wider factors (beyond Generating Technology Class and de-rating factors) need to be considered to enable hydrogen and natural gas blending for power generation in the Capacity Market?

Question 12: Would you expect your plant to require more frequent maintenance / generation outages or incur higher maintenance costs to enable blending of hydrogen and natural gas? If so, could you provide estimated costs?

5. Technical adjustment of interconnector de-rating factors in the Capacity Market

5.1 Context

All technologies which participate in the CM are de-rated to reflect their contribution to security of supply at times of system stress. The CM Rules set out how each technology that may participate in the CM are de-rated.[20] In line with these Rules, NESO are solely responsible for calculating the de-rating factor for the majority of technology classes and these are detailed in their annual Electricity Capacity Report.[21] The responsibility for determining interconnector de-rating factors sits with the government, who consider inputs from NESO and the DESNZ Panel of Technical Experts (PTE)[22] (an independent advisory group appointed by the government, with members across academia and industry). This process was split across these parties to provide assurance against any potential conflicts of interest, and to ensure robust and independent scrutiny of the determined interconnector de-rating factors.[23]

Schedule 3A of the CM Rules sets out the process of determining interconnector de-rating factors:[24]

- Step 1 – NESO calculate a range of de-rating factors for each interconnected country, by undertaking pan-European market modelling that considers a range of plausible scenarios and sensitivities. Detail on NESO's modelling and this range is published in their annual Electricity Capacity Report.
- Step 2 – The DESNZ PTE review and scrutinise NESO's modelling, then recommend a single de-rating factor for each interconnected country from within NESO's calculated range. The de-rating factor for each interconnected country recommended by the PTE is detailed in the annual PTE report.[25]
- Step 3 – The government makes the final decision on the de-rating factor for each individual interconnector. This decision reflects an adjustment for technical reliability determined by the government. The final de-rating factor for each interconnector is published as part of the auction parameters announcement each year.[26]

This section of the CfE seeks views on the third step of this process: the adjustment that the government applies to reflect the technical reliability of interconnectors, which typically has a smaller influence on final determined de-rating factors.

As this step of the process has not been reviewed since it was first implemented in 2015, the government is considering an update to the technical adjustment methodology. There is also

[20] DESNZ, Capacity Market Rules, Chapter 2.3, accessed June 2025.
[21] NESO, Electricity Capacity Report, accessed June 2025.
[22] Gov.uk, Panel of Technical Experts, accessed June 2025.
[23] DECC, Consultation on Capacity Market Supplementary Design Proposals and Transitional Arrangements, 2015.
[24] DESNZ, Capacity Market Rules, Schedule 3A, accessed June 2025.
[25] For example, DESNZ, NESO Electricity Capacity Report 2025: findings of the Panel of Technical Experts, 2025.
[26] For example, DESNZ, Full details of auction parameters and interconnector de-rating factors, 2025.

opportunity for greater transparency around the methodology that the government applies to reflect an adjustment for the technical reliability of interconnectors. As such, the government commissioned Frontier Economics and LCP Delta to provide updated approaches to consider technical reliability which could be applied when determining final interconnector de-rating factors. The report from Frontier Economics and LCP Delta which details these approaches has been published alongside this CfE.[27]

Schedule 3A of the CM Rules states that the government must take into consideration technical reliability when determining the final de-rating factor of each interconnector, without providing detail on the methodology to be applied. The government therefore expects that the proposals detailed below that set out technical updates in approach would not require further changes to CM legislation, such as Schedule 3A; however, as implementing any updated approach would reflect a change of process the government welcomes views from stakeholders to inform the final updated methodology for determining the technical reliability of interconnectors. Stakeholder feedback gathered through this CfE will inform further policy development and subject to final decisions on implementation, the government expects changes may be implemented ahead of the 2026 prequalification window.

5.2 The technical adjustment methodology for interconnector de-rating factors

The technical adjustment is an important step of the interconnector de-rating process as various factors such as interconnector age, outage rates, and technology type may have an impact on the expected contribution each interconnector can have towards security of electricity supply, even between two interconnectors which connect GB to the same country.

In 2015, following the government response which formalised the eligibility of interconnectors to enter the CM,[28] an update was published which outlined each step of the de-rating process in more detail.[29] These publications justified the need for a technical adjustment, noting that a pan-European modelling approach by National Grid (now NESO) would not appropriately take into account operational factors (e.g. transmission losses, technical availability, and interconnector 'ramp rates'). The publication noted that a downward adjustment would be necessary to account for these factors when considering an individual interconnector's contribution to GB security of supply. It proposed that historic interconnector availability during periods of high demand in winter, or analysis prepared by Sinclair Knight Merz (SKM) for Ofgem,[30] could be used to apply this adjustment. This analysis considers the technical parameters of the cables and the converter stations that make up an interconnector to calculate its expected availability and is also used to determine Cap and Floor scheme eligibility.

The proposed technical adjustment methodology recommended in the separate report by LCP Delta and Frontier Economics is summarised in Table 3. This methodology is dependent on the length of time that each interconnector has been operational, and therefore the amount of historic availability data that can be used to consider technical availability. Where there is little

[27] DESNZ, Technical Derating factors for electricity interconnectors, October 2025
[28] DECC, Consultation on Capacity Market Supplementary Design Proposals and Transitional Arrangements, 2015.
[29] DECC, Capacity Market update: de-rating interconnector CMUs, 2015.
[30] Ofgem, Calculating Target Availability Figures for HVDC Interconnectors, 2013.

historic availability data, the most recent SKM model or published characteristics of the interconnector is instead used to derive availability. This methodology can be adapted by the government to include or exclude high-impact low-probability events (as detailed in Section 5.3), but both follow the criteria detailed in the table below in the first instance.

Table 3: Proposed methodology for the technical adjustment for interconnector de-rating factors.

Years in operation "x"	Proposed methodology for technical adjustment
x < 1 year	The technical adjustment is defined as the minimum of the availability range derived using the most recent SKM model, updated with any new engineering data,[31] or where there is little historic availability data, the published characteristics of that interconnector.
1 ≤ x ≤ 7 years	The technical adjustment determined for x < 1 year is adjusted on an annual basis using a moving average, in line with its observed availability during periods of high demand in winter, to take into account updated historical availability data.
x > 7 years	The technical adjustment is defined as the interconnector's average availability during periods of high demand over the last seven winters. Seven years is proposed as this aligns with NESO's approach to availability data for calculating the de-rating factors for conventional generating technologies such as CCGTs and nuclear.[32]
Refurbishing interconnectors	If an existing interconnector undergoes major refurbishment, it may be appropriate for it to be considered as a new interconnector for the purposes of this methodology.

Overall, the government is minded to implement the technical adjustment methodology recommended by Frontier Economics and LCP Delta. The proposed approach maintains predictability and transparency as an interconnector accumulates evidence of its availability over the years. Further information on this approach may be found in the linked report.[33]

The following questions are related to Section 5.2 on the proposed methodology for technical adjustment for interconnector de-rating factors. For all questions, please provide evidence to support your views.

Question 13: Do you agree that the government should implement an updated technical adjustment methodology? Please provide the rationale behind your view.

[31] This new engineering data is published by CIGRE (the International Council on Large Electric Systems).
[32] The methodology for conventional plant de-rating factors is also detailed in the Capacity Market Rules: DESNZ, Capacity Market Rules, Chapters 2.3, accessed June 2025.
[33] DESNZ, Technical Derating factors for electricity interconnectors, October 2025

Question 14: Do you agree that the government should implement the proposed methodology as detailed in Table 3? If not, please provide reasons why, or alternative approaches that could be considered.

Question 15: Are there any unintended consequences to implementing the proposed methodology as detailed in Table 3? If so, please detail these.

5.3 Considering high-impact low-probability events in the technical adjustment methodology

The proposed methodology detailed in Section 5.2 provides an over-arching framework for how the technical de-rating factor would be determined, but also requires a decision on how historic availability data should be considered. This includes whether all outage events should be included, or if high-impact low-probability events should be excluded from the availability assessment.

In their report, Frontier Economics and LCP Delta recommend that the government should exclude high-impact low-probability events that may have been outside reasonable control of the operators from the technical adjustment calculation. Past events may not accurately reflect future performance, particularly events with low likelihood of occurring again; however, to exclude these events from the calculation poses a risk that could lead to interconnectors being designated de-rating factors which over-exaggerate their contribution to security of electricity supply. Examples of high-impact low-probability events detailed in the linked report include: interconnectors which had their availability reduced by their respective System Operators; the fire at the IFA1 terminal in 2021; and undersea cable faults causing outages on BritNed in 2020/21.

If high-impact low-probability events are excluded from the interconnector technical adjustment calculation, NESO could continue to account for these events in their target capacity modelling by including whole winter interconnector outages or new interconnector delays in the calculation of the average non-delivery observed in the most recent five delivery years after the final T-1 target had been set following prequalification.[34]

Conversely, including every high-impact low-probability event could result in a few unexpected events having a potentially over-sized impact on decisions for future expected availability. Individual interconnector de-rating factors could be particularly sensitive to this given the smaller historic datasets available compared to other conventional technologies, where availability assessments that capture similar events are averaged across a larger fleet, not individual units. This may overly penalise interconnectors that were unavailable due to events outside their control or not reward them appropriately for making additional technological improvements.

Table 4 details the difference in calculated technical adjustments from the proposed methodology when including and excluding the high-impact low-probability events provided as examples above. The year in the table represents the corresponding winter, therefore the 2019 values include the cumulative availability for all winters until and including 2019/20 and would therefore be used for interconnectors seeking an agreement in the T-4 auction for the 2022/23

[34] The average non-delivery calculation employed by NESO is described in the annual ECR modelling and assumptions book, for example: NESO, ECR modelling and assumptions book, accessed June 2025.

Delivery Year. This approach would be applied for each year, for example the 2020 values would be used for interconnectors seeking an agreement in the T-4 auction for the 2023/24 Delivery Year.

The maximum availability for interconnectors undergoing high-impact low-probability events in this methodology is set in response to the kind of outage event experienced by the interconnector: e.g. the maximum availability set by the Transmission System Operator where they had instructed a reduction in capacity; the maximum availability set by the interconnector itself when recovering from outage; or, the maximum availability set to 0 MW for a full outage. Further details on how these figures were calculated may be found in the linked report.

Table 4: Technical adjustment percentages determined by including and excluding high-impact low-probability events from the calculation.[35]

Interconnector	Technical adjustment including high-impact low-probability events				Technical adjustment excluding high-impact low-probability events			
	2019	2020	2021	2022	2019	2020	2021	2022
IFA1	98.4%	98.6%	89.6%	87.0%	98.4%	98.6%	97.7%	93.6%
ElecLink	n/a[36]	n/a	98.0%	98.9%	n/a	n/a	98.0%	98.8%
NorthSeaLink	n/a	90.1%	72.7%	81.7%	n/a	90.1%	80.5%	88.0%
EWIC	99.0%	99.1%	95.9%	93.2%	99.0%	99.1%	97.2%	97.0%
NemoLink	98.6%	99.0%	99.3%	99.4%	98.5%	99.0%	99.2%	99.4%
Moyle	78.8%	83.0%	80.6%	77.1%	100%	100%	100%	100%
IFA2	n/a	95.9%	97.7%	97.5%	n/a	95.9%	97.7%	97.5%
BritNed	99.9%	84.3%	86.6%	88.5%	99.9%	99.9%	99.6%	99.7%
Greenlink	n/a	n/a	n/a	97.2%	n/a	n/a	n/a	97.2%
VikingLink	n/a	n/a	n/a	91.9%	n/a	n/a	n/a	91.9%

Where high-impact low-probability events are included in the proposed methodology, volatility in the determined technical adjustment is noted on a year-by-year basis. LCP Delta and Frontier Economics note in their report that the primary reason for this volatility is due to outage events outside of the interconnector's control. These are occasions where an interconnector was technically available but was prevented from importing to GB by external

[35] Note that this work was completed in early 2023, and therefore only covers events as they were included in public databases at the end of 2022.
[36] n/a indicates that an interconnector did not participate in the CM auction held that winter. This information can be found in the Capacity Market Register: NESO, Capacity Market Register, accessed June 2025.

factors. Where certain outage events are not included in the technical adjustment methodology, a more stable trend in de-rating factors is observed.

On balance, the government is minded to generally exclude certain high-impact low-probability events from the technical adjustment calculation. Government will take stakeholder views into consideration when making this decision and will keep this decision under review.

The government is considering publishing a briefing note that would detail the methodology behind the technical adjustment for stakeholders. There is precedent for informing stakeholders of information pertaining to interconnector de-rating factors through published briefing notes. Since 2020, NESO have published interconnected country modelling briefing notes ahead of the ECR to provide greater stakeholder visibility.[37] NESO are clear that these briefing notes do not represent formal industry consultation; however, they enable stakeholder engagement and allow feedback to be shared with the PTE for consideration as part of the ECR modelling scrutiny process.

The following questions are related to Section 5.3 on considering high-impact low-probability events in the technical adjustment methodology for interconnector de-rating factors. For all questions, please provide evidence to support your views.

Question 16: Do you agree that the government should generally exclude high-impact low-probability events from the technical adjustment calculation? Please provide evidence to support your view.

Question 17: Please provide views on which, if any, criteria should lead a high-impact low-probability event to be excluded in the technical adjustment calculation? Please provide the rationale behind your feedback.

Question 18: Are there any unintended consequences to excluding high-impact low-probability events? Please provide evidence to support your view.

Question 19: Do you agree that the government should publish a briefing note to detail the methodology behind the technical adjustment? If there are certain aspects of the technical de-rating process that you think would be helpful to include in this briefing note or in future stakeholder engagement please provide details of these.

Question 20: If you have further comments on the wider interconnector de-rating factor process, please provide details.

[37] For example, NESO, ECR 2025 Interconnected Country Modelling Briefing Note, accessed June 2025.

6. Call for evidence questions

Question 1: What are your views on Hydrogen to Power combustion plants connected to the wider hydrogen network and with natural gas connections participating in the Capacity Market under the existing gas Generating Technology Classes with the associated de-rating factors?

Question 2: What are your views on Hydrogen to Power combustion plants connected to the wider hydrogen network and without natural gas connections participating in the Capacity Market under the existing gas Generating Technology Classes with the associated de-rating factors?

Question 3: What are your views on Hydrogen to Power combustion plants without access to natural gas, but with onsite storage, being categorised as duration limited and therefore participating in the Capacity Market under a Storage Generating Technology Class with the associated de-rating factors?

Question 4: If the government was to implement bespoke Generating Technology Class(es) for Hydrogen to Power plants, what factors would need to be considered when developing the de-rating factor? Please consider both combustion plants and fuel cells.

Question 5: What wider factors (beyond Generating Technology Class(es) and de-rating factors) need to be considered to enable Hydrogen to Power to participate in the Capacity Market?

Question 6: Are there any unintended consequences that could occur from enabling Hydrogen to Power to participate in the Capacity Market?

Question 7: If you are an operator of an existing gas Capacity Market Unit, are you considering onsite blending of hydrogen and natural gas for power generation? Is the current Capacity Market framework sufficient to enable blending?

Question 8: Would the opportunity to blend hydrogen as part of your fuel mix incentivise you to bring forward new or invest in the lifetime extension of existing unabated gas capacity?

Question 9: What are your views on how the government should approach Generating Technology Classes for hydrogen and natural gas blended fuel plants, including whether existing Generating Technology Classes are appropriate?

Question 10: Are there any unintended consequences that could occur from enabling natural gas plants to blend hydrogen in their fuel mix?

Question 11: What wider factors (beyond Generating Technology Class and de-rating factors) need to be considered to enable hydrogen and natural gas blending for power generation in the Capacity Market?

Question 12: Would you expect your plant to require more frequent maintenance / generation outages or incur higher maintenance costs to enable blending of hydrogen and natural gas? If so, could you provide estimated costs?

Question 13: Do you agree that the government should implement an updated technical adjustment methodology? Please provide the rationale behind your view.

Question 14: Do you agree that the government should implement the proposed methodology as detailed in Table 3? If not, please provide reasons why, or alternative approaches that could be considered.

Question 15: Are there any unintended consequences to implementing the proposed methodology as detailed in Table 3? If so, please detail these.

Question 16: Do you agree that the government should generally exclude high-impact low-probability events from the technical adjustment calculation? Please provide evidence to support your view.

Question 17: Please provide views on which, if any, criteria should lead a high-impact low-probability event to be excluded in the technical adjustment calculation? Please provide the rationale behind your feedback.

Question 18: Are there any unintended consequences to excluding high-impact low-probability events? Please provide evidence to support your view.

Question 19: Do you agree that the government should publish a briefing note to detail the methodology behind the technical adjustment? If there are certain aspects of the technical de-rating process that you think would be helpful to include in this briefing note or in future stakeholder engagement please provide details of these.

Question 20: If you have further comments on the wider interconnector de-rating factor process, please provide details.

7. Next steps

This call for evidence will remain open to written responses for eight weeks from 2 October 2025, closing on 27 November 2025. The government will analyse all responses to inform further policy development. A government response is expected in early 2026 to summarise the feedback received.

The government has undertaken analysis as part of the public sector equality duty (PSED) process, and we do not believe that any groups are likely to be disproportionately impacted by the policies. The impact on consumer bills is expected to be negligible, and we do not foresee any impacts on protected groups. We will continue to assess the equality implications of these options and will keep the PSED closely under review. If you have any views on how the policies may impact equality, please indicate this in your response.

8. Glossary

Abbreviation/Term	**Definition**
Capacity Agreement	The rights and obligations accruing to a Capacity Provider under the CM Regulations and the Rules in relation to a CMU for one or more Delivery Years.
Capacity Auction	An auction held under Part 4 of the Regulations, as a result of which successful bidders are awarded Capacity Agreements.
Capacity Market (CM)	A mechanism to contract reliable sources of capacity, and ensure they respond when needed, to help support security of supply. This results in payment to any Capacity Provider who can respond when called on by the CM Delivery Body in times of system stress. Auctions for this capacity take place both four years (T-4) and one year (T-1) ahead of delivery, and agreements generally last for one year.
Capacity Market Rules (“the CM Rules” or “the Rules)	The CM Rules provide the technical detail for implementing the operating framework set out in the Regulations.
Capacity Market Unit (CMU)	A unit of electricity generation capacity or DSR capacity that can be put forward in a capacity auction. It is the product that forms the capacity to be purchased through the CM.
Capacity Provider	A person who holds a Capacity Agreement or a transferred part in respect of a Capacity Agreement.
Capital Expenditure (CAPEX)	Money spent by a business or organisation on acquiring or maintaining fixed assets, such as land, buildings, and equipment.
CM Delivery Body	National Energy System Operator (NESO).
Combined-Cycle Gas Turbine (CCGT)	(i) An electricity generation technology in which a gas turbine and a steam turbine are used in combination to achieve greater efficiency. (ii) A GTC in Schedule 3 of the CM Rules.

Combined Heat and Power (CHP)	(i) An electricity generation technology which captures and utilises the waste heat produced by the electricity generation process. (ii) A GTC in Schedule 3 of the CM Rules.
De-rated Capacity	The capacity that a CMU is likely to be technically available to provide at times of peak demand, which is specific to the CMU's technology type and individual characteristics.
De-rating Factor	De-rating factors are applied to all forms of electricity generation in the CM to reflect that 100% of capacity will not be available 100% of the time. This is because generating plants can break down from time to time, and wind and solar outputs varies day to day.
Dispatchable Power Agreement (DPA)	A private law contract between a carbon emitting electricity generator and the DPA Counterparty, which will be the Low Carbon Contracts Company Ltd, issued pursuant to Section 10 of the Energy Act 2013, as a type of CfD. The contract will set out the terms for capturing and storing carbon and the compensation which the generator will receive in return.
Electricity Capacity Regulations ("the CM Regulations" or "the Regulations")	This refers to the Electricity Capacity Regulations 2014, S.I. 2014/2043, the principal regulations underpinning the CM.
Flexibility	The ability to shift the consumption or generation of energy in time or location. Flexibility is critical for balancing supply and demand, integrating renewables, and maintaining the stability of the system. Flexibility technologies include power CCUS, H2P, LDES, flexible demand and interconnectors.
Generating Technology Classes (GTC)	A class of Generating Unit, defined by the technology used to generate electricity, for which the Secretary of State requires the CM Delivery Body to publish a De-Rating Factor.
Generator	(i) Any equipment that produces electricity, including equipment which produces electricity from storage; and (ii) A business which operates such equipment.

Gigawatt (GW)	A unit of capacity (1000 megawatts).
Hydrogen to power (H2P)	The conversion of low carbon hydrogen to produce low carbon electricity.
National Energy System Operator (NESO)	An independent, public corporation responsible for planning Britain's electricity, gas and hydrogen networks, as well as operating the electricity system. In the GB electricity system, NESO performs several important functions, from second-by-second balancing of electricity supply and demand, to developing markets and advising on network investments. NESO replaced the National Grid Electricity System Operator on 1 October 2024.
Open Cycle Gas Turbines (OCGT)	(i) An electricity generation technology using a gas turbine without exhaust gas heat recovery. (ii) A GTC in Schedule 3 of the CM Rules.
Panel of Technical Experts (PTE)	An advisory group of independent consultants who were appointed by the government to perform a specific and technical function as part of the first Electricity Market Reform delivery plan process.
Unabated (gas) generation	Electricity generation where carbon dioxide from burning natural gas is not captured and stored.
Reciprocating engine	(i) An electricity generating technology using a reciprocating pistons driving a rotating shaft. (ii) A GTC in Schedule 3 of the CM Rules.
System Stress Event	A System Stress Event occurs only when i) a demand control event has occurred and ii) that demand control event has been confirmed after post-event analysis, conducted by NESO, to have been definitively triggered by a national shortage of generation resources.

This consultation is available from: https://www.gov.uk/government/calls-for-evidence/capacity-market-hydrogen-and-interconnectors

If you need a version of this document in a more accessible format, please email alt.formats@energysecurity.gov.uk. Please tell us what format you need. It will help us if you say what assistive technology you use.