Department for
Energy Security
& Net Zero

Decarbonisation Readiness

Consultation on updates to the 2009 Carbon Capture Readiness requirements

Closing Date: 24 April 2023

Any enquiries regarding this publication should be sent to us at:
electricity.security@beis.gov.uk

Executive summary

In July 2021, the UK Government and Welsh Government published a joint call for evidence[1] seeking initial views on updating the 2009 Carbon Capture Readiness (CCR) requirements[2] to ensure all new build combustion power plants have a viable route to decarbonisation; make the requirements more flexible and simpler; provide a clear decarbonisation pathway for combustion power plants and keep pace with the evolving nature of decarbonisation technologies, in particular low carbon hydrogen. To reflect this update, we proposed to rename CCR to Decarbonisation Readiness (DR).

Government sees low carbon hydrogen as a critical component of our broader strategy to deliver energy security, create economic growth and contribute to our net zero target. Hydrogen will enable us to use our domestic energy assets, including gas and renewables, to decarbonise UK industrial sectors, power, heavy transport, and potentially home heating. DR requirements could contribute to Government's ambitions of developing the hydrogen economy through creating a pathway for hydrogen to power plants to form a large and reliable source of hydrogen demand.

Deployment of power Carbon Capture, Usage and Storage (CCUS) is key to the delivery of a low-cost decarbonised power sector, vital to meeting the UK's sixth Carbon Budget (CB6) and achieving our net zero ambitions. The deployment of CCUS infrastructure could create up to 48,000 high value jobs[3] and transform our industrial regions. The Government intends to support the construction of the UK's first CCUS power plant by the mid-2020s.

DR requirements are a key part of the Government's framework to support the expansion of the hydrogen and CCUS economies by providing clear pathways for these technologies. The requirements also support the Government's commitments to decarbonise the power sector by ensuring that new and substantially refurbishing generation is in the best possible position to take advantage of decarbonisation opportunities in future.

This consultation builds on the call for evidence by setting out our formal proposals for DR, alongside a summary of responses to the call for evidence. The proposals outlined in this consultation will apply to England only. The Welsh Government will issue a separate response and outline of next steps in Wales.

In summary, we propose:

- Removing the 300 MW minimum capacity threshold at which the requirements apply. This should simplify the requirements, remove a potential market distortion and support the rapid decarbonisation of the electricity system.

- Enabling combustion power plants to demonstrate decarbonisation readiness through conversion to hydrogen firing by introducing four assessments and accompanying guidance for demonstrating Hydrogen Conversion Readiness (HCR) which broadly reflect those for CCR. As with CCR, the HCR tests will enable developers to maximise decarbonisation opportunities as the hydrogen economy and infrastructure expands. Providing decarbonisation options will also ensure combustion power plants can

[1] https://www.gov.uk/government/consultations/decarbonisation-readiness-call-for-evidence-on-the-expansion-of-the-2009-carbon-capture-readiness-requirements
[2] https://www.gov.uk/government/publications/carbon-capture-readiness-ccr-a-guide-on-consent-applications
[3] https://www.gov.uk/government/publications/energy-innovation-needs-assessments

develop a viable decarbonisation plan which best suit their individual circumstances.

- Moving the DR requirements from the planning consent process to the environmental permitting process. Consolidating the requirements into the environmental permitting regime, which already houses other environmental requirements, should lead to overall simpler regulatory requirements. This should also allow the requirements to be amended more readily to respond to future market or technical developments. The Environment Agency (EA) would be responsible for the regulation of the requirements in England.

- Expanding the generation technologies in scope to include biomass (as well as biogas from anaerobic digestion), energy from waste (EfW), and combined heat and power (CHP) to support the rapid decarbonisation of the electricity system, complement existing technology-specific decarbonisation policies, and make the requirements simpler and more consistent across technology types.

- Applying transitional arrangements to the implementation of DR, to ensure that policy is not changed for plants for which investment decisions have already been. This will ensure that investor confidence is preserved.

- Including both new build and substantially refurbishing combustion power plants in scope and enabling existing combustion power plants to voluntarily apply for a DR permit.

- Updating the current tests and guidance for demonstrating CCR in line with technical and policy developments.

- Establishing the objectives for DR requirements, and the definition of "decarbonisation" within the context of DR.

- Retaining the current CCR requirement for developers to undertake a light touch review of their plant's compliance with the DR requirements every two years to ensure all regulated developers are regularly assessing their decarbonisation potential.

- Introducing a regular review to be undertaken by Government of the DR requirements through the Regulation 80 of the Environmental Permitting Regulations (EPR).[4] This would ensure the requirements are meeting their objectives, are fit for purpose and as simple as possible, and whether updates can be made to make the requirements more effective at meeting their objectives.

Following the Call for Evidence, Government also commissioned two technical studies on "Hydrogen Readiness" and "Carbon Capture Readiness" to provide the evidence base for informing both assessors and developers on the Decarbonisation Readiness requirements. These have been published alongside this consultation.

Next steps

[4] https://www.legislation.gov.uk/uksi/2016/1154/contents/made

The consultation will run for **six weeks**.

Following this consultation, we would expect to issue a Government Response and then amend the relevant legislation (the Carbon Capture Readiness Regulation 2013 and the Environmental Permitting Regulations 2016) shortly thereafter.

We propose for the DR requirements to come into force for newly built and substantially refurbishing plants from **1 July 2024**. This should allow sufficient time after the legislation has been made for the Environment Agency to carry out any further necessary engagement with stakeholders and publish any further guidance or supporting documents on the requirements, ahead of them coming into force.

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1. Introduction

1.1 Background

The current Carbon Capture Readiness (CCR) requirements were introduced in 2009 to ensure that planning consent was only granted to combustion power plants in England and Wales sized above 300 MW which could demonstrate it was technically and economically feasible that carbon capture technology could be retrofitted within the lifetime of the plant.[5] Since the CCR requirements were introduced, the GB energy landscape has fundamentally changed with a strong need to go further and faster on the decarbonisation of power sector to reach both our Carbon Budget Six (CB6) commitment and Government's own commitment to decarbonise the power system by 2035, subject to security of supply.[6]

In the December 2020 Energy White Paper (EWP),[7] Government committed to update the current CCR requirements to maximise the decarbonisation potential of new build combustion power plants and ensure the requirements were flexible to adapt to rapidly evolving decarbonisation technologies of carbon capture, usage and storage (CCUS) and hydrogen to power. In July 2021, jointly with Welsh Government, we published a call for evidence[8] seeking views on possible expansions and advancements to the CCR requirements.

The call for evidence sought views on updating the CCR requirements to include nearly all new build combustion power plants by removing the 300 MW threshold; including more combustion technologies within scope; and extending the requirements to include substantially refurbishing combustion power plants. We also sought views on introducing hydrogen generation as an alternative decarbonisation route alongside conversion to carbon capture and storage. 34 responses were received from a range of stakeholders with general feedback being positive.

Based on this feedback and further stakeholder engagement we are proposing to update the scope of the current CCR requirements with a name change to Decarbonisation Readiness (DR) to reflect this. The proposals for DR outlined in this consultation set both a clear direction and provide a pathway for the decarbonisation of high carbon combustion power plants. They could ensure that new and substantially retrofitting generation is in the best possible position to take advantage of future decarbonisation opportunities.

Following the call for evidence, the Welsh Government will issue a separate response and outline of next steps. The proposals outlined in this consultation will apply to England only.

Government also commissioned two technical studies following the call for evidence on "Hydrogen Readiness" and "Carbon Capture Readiness" in order to provide the evidence base to inform requirements for developers to demonstrate Decarbonisation Readiness. They may also be used by the Environment Agency (EA) to underpin the information outlined in any future permitting guidance for developers. The studies have been published alongside this consultation.

[5] https://www.gov.uk/government/publications/carbon-capture-readiness-ccr-a-guide-on-consent-applications
[6] https://www.gov.uk/government/news/plans-unveiled-to-decarbonise-uk-power-system-by-2035
[7] https://www.gov.uk/government/publications/energy-white-paper-powering-our-net-zero-future
[8] https://www.gov.uk/government/consultations/decarbonisation-readiness-call-for-evidence-on-the-expansion-of-the-2009-carbon-capture-readiness-requirements

1.2 Summary of areas covered and response to the call for evidence

In total, 34 responses were received to our July 2021 call for evidence from a range of stakeholders, including developers and trade associations. The proposals were broadly supported by the respondents to the call for evidence and the feedback collected has been used to refine the proposals presented in this consultation. Listed below are areas the call for evidence sought views on and a summary of the responses received:

- Removing the 300 MW minimum capacity threshold at which the requirements apply. This should remove market distortions and support the rapid decarbonisation of the electricity system. The majority of respondents supported the removal of the 300 MW threshold.
- Moving the Decarbonisation Readiness requirements from the planning consent process to the Environmental Permitting Regulations 2016 (EPR).[9] This should allow the requirements to be amended more readily to respond to future market or technical developments. The Environment Agency (EA) would be responsible for the implementation of the requirements in England. The majority of respondents supported this proposal.
- Introducing the option to comply with Decarbonisation Readiness through hydrogen conversion, in addition to the retrofitting of carbon capture and storage (CCUS) technologies. This should provide an additional decarbonisation option, and one which may be more suitable for smaller combustion power plant and/or 'peaking' combustion power plants (i.e. plants with a lower load factor) for which CCUS conversion would be potentially impractical due to either economic or technical constraints. The option would also be available for larger sized plants where CCUS may be possible, but hydrogen conversion could also be a cost-effective option or more attractive due to practical limitations such as siting. This will require the development of new assessments to determine hydrogen conversion readiness. The majority of respondents supported enabling developers to comply with DR requirements by demonstrating Hydrogen Conversion Readiness (HCR).
- Expanding the scope of Decarbonisation Readiness to include some technologies which were previously excluded from CCR; for example, biomass, energy from waste (EfW) and combined heat and power (CHP). This should support the rapid decarbonisation of the electricity system and complement existing technology-specific decarbonisation policies. There were mixed views on whether to include technologies such as biomass, EfW and CHP within DR.
- Ensuring that the economic and technical feasibility assessments for demonstrating Carbon Capture Readiness (CCR) are updated to reflect developments including, for example, the 2021 consultation on how to sequence industrial clusters,[10] as well as the UK Hydrogen Strategy.[11] This will ensure that the assessments fit with wider Government policy.
- Allowing developers the flexibility to choose between CCUS, hydrogen conversion and any other decarbonisation technologies which may be included in DR in the future. This should enable developers to respond to emerging market or technical developments and make

[9] https://www.legislation.gov.uk/uksi/2016/1154/contents/made
[10] https://www.gov.uk/government/consultations/carbon-capture-usage-and-storage-market-engagement-on-cluster-sequencing
[11] https://www.gov.uk/government/publications/uk-hydrogen-strategy

effective business decisions which both reflect their individual circumstances and enable decarbonisation efforts.

- Ensuring that the assessments for DR are achievable for developers and minimise barriers to investment in dispatchable generation, whilst also being meaningful in ensuring combustion power plants have a viable route to decarbonisation. A majority of respondents supported the proposed design principles for DR.

1.3 Summary of proposals in this consultation

Following the feedback from both the 2021 Call for Evidence and subsequent stakeholder engagement, we are proposing the following:

- Renaming the requirements as "Decarbonisation Readiness" (DR) requirements, to reflect the updated scope.
- Removing the 300 MW minimum capacity threshold at which the requirements apply so that all eligible combustion power plants of any size would be subject to DR requirements.
- Expanding the electricity generating technologies within scope of DR to include biomass (as well as biogas from anaerobic digestion), energy from waste (EfW), and combined heat and power (CHP).
- Including both new build and substantially refurbishing combustion power plant in the scope of DR requirements and enabling existing plants to voluntarily apply for a DR permit.
- Moving the DR requirements from the planning consent process to the environmental permitting process (EPR) to allow for the requirements to be amended more readily to respond to future market or technical developments. The Environment Agency (EA) would be responsible for the regulation of the requirements in England.
- Updating the current tests and guidance for demonstrating Carbon Capture Readiness (CCR) in line with technical and policy developments.
- Enabling combustion power plants to demonstrate decarbonisation readiness through conversion to hydrogen generation by introducing four tests and accompanying guidance for demonstrating Hydrogen Conversion Readiness (HCR) which broadly reflect those for CCR.
- Establishing the objectives for DR requirements, and the definition of "decarbonisation" within the context of DR.
- Retaining the current CCR requirement for developers to undertake a light touch review of their plant's compliance with the DR requirements every two years to ensure all regulated developers are regularly assessing their decarbonisation potential.
- Introducing a regular review to be undertaken by Government of the Decarbonisation Readiness requirements through the Regulation 80 of the Environmental Permitting Regulations (EPR).[12] This would ensure the requirements are meeting their objectives, are fit for purpose, and whether updates can be made to make the requirements more effective at meeting their objectives.

[12] https://www.legislation.gov.uk/uksi/2016/1154/contents/made

- Continuing to use the six design principles introduced in the call for evidence as the basis for developing the DR requirements. These are:
    1. assessments should strike a careful balance between being meaningful, but also achievable;
    2. the assessments should be based upon a "no barriers" approach;[13]
    3. developers should be able to change their chosen decarbonisation technology prior to implementation;
    4. passing the assessments should be mandatory, with the exception of the economic feasibility assessment, and in the short term, the hydrogen fuel access test;
    5. the two sets of separate assessments (i.e. the HCR and CCR assessments) should be broadly equivalent and mirror one another as far as possible; and,
    6. where possible, the robustness of the demonstration of decarbonisation readiness should be proportionate to the capacity of the plant under development.
- We do not propose to bring within scope of the DR requirements any other decarbonisation technologies in addition to hydrogen and CCUS as part of this consultation.

1.4 How to Respond

This consultation will be open for **six weeks** from 13 March 2023 until **24 April 2023**. Please submit your response to this consultation by **11:59pm on 24 April 2023**. 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.

Respond online at: https://beisgovuk.citizenspace.com/energy-strategy-networks-markets/decarbonisation-readiness-requirements

or

Email to: electricity.security@beis.gov.uk

1.5 Confidentiality and data protection

This consultation is being undertaken on behalf of the Department for Energy Security and Net Zero (DESNZ). Information you provide in response to this consultation, 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).

[13] i.e. that applicants should be required to demonstrate that there are no known barriers to the technical or economic viability of their decarbonisation route.

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.

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

2. Defining Decarbonisation Readiness

2.1. Background

In October 2021, Government announced its commitment to decarbonise the electricity system by 2035, subject to security of supply.[14] The recent British Energy Security Strategy (BESS) reinforced Government's intention in going further and faster to reach this commitment and reach our targets for Carbon Budget Six (CB6) and net zero.[15] The decarbonisation of our electricity system will be fundamental in decarbonising the wider economy through the electrification of transport, heating, and industrial processes.

Over the coming decade, significant volumes of new build capacity will be required to replace high carbon capacity and retiring older capacity, and as electrification of the economy increases overall electricity demand. Whole system modelling for the Net Zero Strategy showed that by 2050 CO_2 emissions associated with power would need to drop by 95-98% compared to 2019,[16] and 80-85% by 2035.[17] Therefore, increasing volumes of this new build capacity will need to be low carbon flexible capacity, including electricity storage, hydrogen to power, gas and biomass with Carbon Capture Usage and Storage (CCUS), and Demand Side Response (DSR).

Some of these technologies currently face barriers to deployment including investor uncertainty and limited deployment of necessary infrastructure (e.g. CCUS transport and storage networks). Government is actively developing policies and pathways to remove barriers and provide support to low carbon flexible technologies. In the short to medium term, high carbon capacity such as unabated gas will likely need to come forward to meet capacity demand and ensure security of electricity supply.

Delivering a decarbonised electricity system at least cost to consumers whilst maintaining security of supply will mean ensuring high carbon combustion generation has clear and simplified decarbonisation pathways to converting to low carbon technologies including hydrogen generation and CCUS.

DR requirements will ensure that new and substantially refurbishing combustion power plants are in the best possible position to take advantage of decarbonisation opportunities in future.

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[14] https://www.gov.uk/government/news/plans-unveiled-to-decarbonise-uk-power-system-by-2035
[15] https://www.gov.uk/government/publications/british-energy-security-strategy
[16] https://www.gov.uk/government/publications/net-zero-strategy
[17] These figures are based on an indicative power sector pathway contributing to the whole-economy net zero and interim targets

Outlining the objectives of this policy and defining what we mean by "decarbonisation" in the context of DR will be key in successfully establishing pathways for combustion power plants to decarbonise.

2.1.1 Unabated Gas Generation Transition

Whilst unabated gas generation currently plays a key role in ensuring our electricity system remains stable and secure, the expansion of flexible low carbon alternatives and a growing proportion of renewable generation means it will run less frequently in future.

In the short term we expect some new build unabated gas capacity to continue to come forward to provide flexible generation and security of supply. The decarbonisation of existing unbated gas generation, where possible, will be key to reaching our ambitious CB6 and net zero targets alongside the rapid deployment of new build low carbon flexible technologies. Furthermore, DR will support our wider ambition outlined in the July 2022 Review of Electricity Market Arrangements (REMA) consultation to reduce our dependence on fossil fuelled generation and our exposure to volatile global gas markets, maximise our use of domestic energy sources, and promote diversity of supply and system resilience.[18]

We recognise that there is currently a large volume of unabated gas capacity on the system with long term Capacity Market (CM) agreements. For example, the T-4 CM auction held in 2023 brought forward 2.1 GW of new build unabated gas capacity with capacity agreements running until 2041. To reduce the risk of unabated capacity being locked into the system, Government is actively enabling the clear decarbonisation pathways unabated generation will need to transition as the enabling low carbon infrastructure for hydrogen and CCUS expands. In the January 2023 CM consultation,[19] we sought views on enabling unabated generators to exit an existing multi-year CM agreement in order to access a new CM agreement or alternative support schemes in order to decarbonise, subject to ensuring continued security of supply and certain conditions being met. This consultation builds upon these foundations through proposals in Section 3.3 to enable developers of existing capacity to voluntarily apply for a DR permit to demonstrate there are no known barriers to their plant decarbonising. This could provide CM agreement holders with a route to demonstrate their decarbonisation potential.

The January 2023 CM consultation also included proposals to strengthen the CM emission limits from 1 October 2034. Implementation of this proposal will be subject to detailed analysis of any impact to security of supply from the late 2020s.

2.2 Expanding Hydrogen to Power and Power CCUS Deployment

Whilst we cannot predict today exactly what the generating mix will look like in 2050, we can be confident that renewables will play a key role. However, to decarbonise whilst maintaining security of supply and keeping costs low, we will need to balance renewable variability against demand. Power CCUS and hydrogen to power can provide non-weather dependent and dispatchable low carbon generation. Furthermore, a high proportion of ancillary services (e.g., inertia, voltage control, frequency control and system restoration) are currently provided by

[18] https://www.gov.uk/government/consultations/review-of-electricity-market-arrangements
[19] https://www.gov.uk/government/consultations/capacity-market-consultation-strengthening-security-of-supply-and-alignment-with-net-zero

unabated fossil fuel-fired generation. Hydrogen to power and power CCUS can replace this capacity and vital system services due to the close similarity in technology between unabated gas generation and these technologies. Government considers these to be vital to support our 2035 power system decarbonisation commitments alongside system flexibility and other low carbon flexibility technologies and services including short and long duration electricity storage and demand side response (DSR).

Government views the DR requirements as providing a clear direction of travel that high carbon generation must increasingly be replaced by, or converted to, low carbon forms of generation including power CCUS and hydrogen to power. The requirements also ensure new build and substantially refurbishing high carbon plants are built such that they can easily decarbonise and so also provide a clear decarbonisation pathway. Government is also actively developing a range of policies and pathways on hydrogen to power and power CCUS which will support individual plants to decarbonise and help drive the expansion of these emerging sectors.

2.2.1 Hydrogen to Power

Government views hydrogen to power as an important component of our future power system. Hydrogen to power involves power plants firing low carbon hydrogen fuel. It has the potential to be vital in achieving our decarbonisation targets by providing a large source of firm and flexible low carbon generation that is capable of fast ramping, as we integrate more intermittent renewables. It also provides an additional route for the decarbonisation of existing unabated combustion generation. Hydrogen to power plants, firing electrolytic or green hydrogen, could also reduce GB's dependence on natural gas.

Government analysis shows that having hydrogen available in the power sector could achieve lower emissions at a lower cost than scenarios without hydrogen.[20] To ensure that developers of both new build and existing combustion power plants are in the best possible position to take advantage of hydrogen decarbonisation opportunities, we are currently actioning our Net Zero Strategy commitment to explore the system need and case for further market intervention in hydrogen to power. This includes assessing how markets and policies could best facilitate hydrogen to power plants coming forward and identifying potential barriers to deployment.

In the BESS, Government doubled the UK ambition for low carbon hydrogen production capacity to up to 10 GW by 2030, with at least half of this from electrolytic hydrogen. Electrolytic hydrogen is especially valuable for flexibility and as an energy storage solution. Excess low carbon electricity can be used to produce hydrogen, which can be stored over time in large quantities and used flexibly to generate power when there is less sun or wind, enabling more efficient utilisation of our large and increasing renewable electricity production capacity. Hydrogen to power as a potentially significant off-taker of hydrogen can play a role in helping support investment in, and ramp up of, early hydrogen production projects by creating sources of demand.

The Government is providing capital and revenue support for low carbon hydrogen producers through the Net Zero Hydrogen Fund and the Industrial Decarbonisation and Hydrogen Revenue Support (IDHRS) scheme respectively. Revenue support from the IDHRS scheme will be provided to producers via the Government's Hydrogen Production Business Model to overcome the operating cost gap between low carbon hydrogen and high carbon

[20] https://www.gov.uk/government/publications/modelling-2050-electricity-system-analysis

counterfactual fuels. Up to £100 million of funding will be awarded through contracts in 2023 to deliver up to 250 MW of electrolytic hydrogen production capacity.[21]

Hydrogen in the power system, therefore, has considerable potential to provide significant hydrogen demand and aid the development of the hydrogen economy, provide electricity balancing services, and increase overall power system flexibility and support the UK's energy security. Hydrogen transport and storage infrastructure (T&S) is key to achieving this. Storage will be needed to ensure certainty of supply for hydrogen to power generation, and transport infrastructure will be needed to connect hydrogen production, hydrogen storage and power generators. The importance of this is reflected in Government's commitment to designing, by 2025, new business models to support the development of hydrogen T&S infrastructure.

2.2.2 Power CCUS

The Net Zero Strategy (NZS) and the BESS re-iterated the critical role of carbon capture, usage and storage (CCUS) in delivering net zero by 2050, and the Government's commitment to a fully decarbonised electricity system by 2035, subject to security of supply. Power generation with CCUS, power CCUS, will be vital to both objectives.

Gas-fired power CCUS can provide non-weather dependent, dispatchable low carbon generation. As noted in Section 2.2, we consider this to be vital alongside other flexible technologies, such as hydrogen to power and energy storage, as well as system flexibility to support a heavily renewables-based system in 2050. As the BESS set out, there is no contradiction between our commitment to net zero and our commitment to a strong and evolving North Sea industry which will reduce the UK's reliance on imported fossil fuels. Decarbonisation of the continued use of gas in power, including through the deployment of power CCUS, will be important in the transition towards net zero.

Deployment of power CCUS is key to the delivery of a low-cost decarbonised power sector and as laid out in the Net Zero Strategy we need to deploy all major low-carbon generation sources at close to their maximum rate. Significant growth of power CCUS will be required, and Government's illustrative scenarios published alongside the Net Zero Strategy shows that to meet our Carbon Budget 6 targets,[22] we could need to deploy as much as 10 GW of power CCUS by 2035.[23]

We are seeking to bring forward at least one power CCUS plant in the mid-2020s. To achieve this, we have developed the Dispatchable Power Agreement (DPA), a business model funded by consumer subsidies which will enable power CCUS to play a valuable mid-merit role in our generation mix. In November 2022, following a successful consultation on the proposed business model, we published the contractual terms and conditions that we intend to enter into negotiations with power projects shortlisted under Track 1 Phase 2 of the cluster sequencing process.

In addition, we will aim to begin competitive allocation for power CCUS plants in the 2020s to support a future pipeline of projects and support cost reduction. This will help give important visibility of future deployment to the supply chain and future project developers. We will also continue to review and evolve the policy framework we have set out to stimulate the delivery of

[21] https://www.gov.uk/government/consultations/design-of-a-business-model-for-low-carbon-hydrogen
[22] https://www.gov.uk/government/news/uk-enshrines-new-target-in-law-to-slash-emissions-by-78-by-2035
[23] Energy and emission projections: Net Zero Strategy baseline (2022), Annex O Supplementary data: Total electricity generating capacity (net zero scenarios in Annex L format) https://www.gov.uk/government/publications/energy-and-emissions-projections-net-zero-strategy-baseline-partial-interim-update-december-2021

future power CCUS projects. Consequently, in July 2022 we launched a call for evidence on the future policy framework for the delivery of power CCUS. This call for evidence closed on 17th October 2022 and we will publish the Government response this spring. These announcements and the publication of our call for evidence show an acceleration of our ambition and highlight the importance of power CCUS deployment in the longer term.

We remain conscious of the need to continue to coordinate the approach to power CCUS and the buildout of an expanding transport and storage network for CO_2. In the NZS, the Government committed to delivering four CCUS clusters, capturing 20-30 Mt CO_2 per year across the economy by 2030. Government is providing support to industry in order to establish these clusters. They are integral to the efficient and cost-effective decarbonisation of our economy and are vital to transforming hard to abate sectors. They will play an important role in levelling up the economy, supporting the low-carbon economic transformation of our industrial regions, and creating new high value jobs. CCUS-enabled clusters will be the starting point for a new carbon capture industry, which could support up to 50,000 jobs in the UK in 2030.[24]

CO_2 T&S networks provide the ability to remove CO_2 emissions at their source and permanently store this CO_2 in the subsurface geological formations. With an estimated 78 billion tonnes of CO_2 storage capacity in the UK continental shelf, the UK can lead the world both in the provision of CO_2 services and in the storage of CO_2 emissions. As they are likely to be operated as monopolies, Government will build on the UK's global reputation for regulatory stability and transparency by establishing independent economic regulation for T&S networks. The T&S Regulatory Investment (TRI) Model is therefore being developed with three key objectives: to attract investment in the T&S network to establish a new CCUS sector; enable low-cost decarbonisation in multiple sectors; and develop a market for carbon capture – a long-term vision.

The development of T&S networks, alongside the widespread deployment of CCUS technology, should present the right opportunities for decarbonisation ready plants to convert to power CCUS in the future.

2.2 Defining Decarbonisation Readiness

Driving the decarbonisation of the power sector and supporting existing and forthcoming high carbon capacity to decarbonise requires Government to set clear and ambitious decarbonisation targets for the power sector alongside maximising decarbonisation opportunities.

We therefore propose that decarbonisation in the context of DR is defined as a complete or near complete CO_2 emissions reduction from a power plant, relative to that plant being unabated. This would mean either:

- the installation and continued operation of 100% hydrogen-firing generation; or
- the installation and continued operation of a minimum 90% capture rate CCUS technology of facility CO_2 emissions, or the capture rate defined in best available techniques (BAT) guidance where applicable, whichever is higher.

Under the DR requirements, Government is proposing that a combustion power plant would need to have achieved either of these definitions to be classed as "fully decarbonised" in the

[24] Energy Innovation Needs Assessment (EINA, 2019) https://www.gov.uk/government/publications/energy-innovation-needs-assessments

context of DR. If when a combustion power plant has been converted and meets either of the definitions above through continued operation, then the plant would no longer have to comply with DR requirements. For example, if a developer were to begin operating their combustion power plant with a 30% blend of hydrogen by volume, the plant would still be required to comply with DR requirements until its conversion and continued operation at 100% hydrogen firing.

Government recognises that whilst blends of hydrogen and natural gas can reduce an individual plant's CO_2 emissions, reaching our CB6 and net zero targets for a decarbonised electricity system will mean maximising decarbonisation opportunities across the system.

We also note that in the context of DR we would not differentiate between sources of hydrogen in determining whether a plant firing hydrogen is decarbonised. Emissions related to the production of hydrogen would be accounted at the point of production. Government has developed a Low Carbon Hydrogen Standard, applicable across different hydrogen production methods, which sets a maximum threshold for greenhouse gas emissions allowed in the production process for hydrogen to be considered 'low carbon'. [25] Compliance with the standard will help ensure new low carbon hydrogen production which is then used in power generation makes a direct contribution to our carbon reduction targets.

We propose that CCUS decarbonisation is defined at a minimum 90% capture rate for DR. This is in line with the eligibility for a DPA. However, for capture plant proposals where BAT guidance applies, the plant would be required to be capable of achieving BAT to pass. For example, for post-combustion carbon capture (PCC) utilising amine-based technology, this requires plants to demonstrate a design CO_2 capture rate of at least 95%.[26]

We propose the definition of decarbonised could be included in the eligibility criteria for the DR requirements within a new 'Decarbonisation Readiness' added to the EPR.

Consultation Question 1:

Do you agree with Government's proposal for the definition of "fully decarbonised"?

Consultation Question 2:

What are your views on our proposals that eligible combustion power plants would be subject to Decarbonisation Readiness requirements unless they can demonstrate they have met the definition of being "fully decarbonised"?

2.3 Objectives of Decarbonisation Readiness

The intention of DR is to provide a clear decarbonisation pathway for new build and substantially refurbishing plants, and for existing high carbon combustion power plants voluntarily decarbonising. This requires developers to create a viable plan for how their plant can achieve decarbonisation according to its individual circumstances.

The process of developers being required to demonstrate the viability of their decarbonisation plan should minimise the risk of individual plants becoming 'stranded assets' whereby future policy actions and/or technological developments prevent these plants from earning an

[25] https://www.gov.uk/government/publications/uk-low-carbon-hydrogen-standard-emissions-reporting-and-sustainability-criteria
[26] https://www.gov.uk/guidance/post-combustion-carbon-dioxide-capture-best-available-techniques-bat

economic return on their investment. The design of the DR requirements will be fundamental in achieving this objective. As outlined in Section 6, the requirements are intended to be appropriately flexible to enable developers to update and amend their plans to reflect changing technological and/or economic conditions. Similarly, proposals for Government to regularly review the requirements in line with Regulation 80 of the Environmental Permitting Regime (EPR) (see Section 5.2) should ensure the requirements keep pace with wider technological and economic developments whilst allowing sufficient time for the industry to develop.

We propose to introduce new objectives for the Decarbonisation Readiness requirements as:

1. To provide developers with a clear pathway for combustion power plants within scope of DR requirements to decarbonise.

2. To minimise the risk of high carbon combustion power plants from becoming 'stranded assets' i.e., prematurely unable to operate economically because those plants were not adequately prepared for decarbonisation.

These objectives would be included as part of the proposed new 'Decarbonisation Readiness' schedule in the EPR and form part of the Regulatory Provisions against which DR would be regularly reviewed in accordance with EPR Regulation 80.

Consultation Question 3:

Do you agree with the three proposed objectives of the Decarbonisation Readiness requirements?

3. Scope of Decarbonisation Readiness

3.1 Territorial Scope of Decarbonisation Readiness

The current Carbon Capture Readiness (CCR) requirements apply in Great Britain. The update to CCR that we are proposing in this document would apply to **England only**. Therefore, the current CCR requirements would continue to apply in Wales and Scotland.

3.2 The 300 MW threshold

3.2.1 Background

The current CCR requirements only apply to plants sized above 300 MW. This reflects the fact that at the time the CCR requirements were introduced, most new build plants were sized over 300 MW. And in addition, it was challenging for plants sized below 300 MW to demonstrate the economic feasibility of CCUS. This 300 MW threshold has created an unintended market distortion, by disincentivising the deployment of plants above 300 MW. This has been demonstrated by a number of new gas-fired plants being consented in the last few years at a size of 299 MW.

In addition, the context has changed significantly since the CCR requirements were introduced in 2009. Our climate targets have become more ambitious, with the goal of delivering a decarbonised power system by 2035, subject to security of supply. And a much greater proportion of new build power plants are sized below 300 MW. For example, in Capacity Market (CM) auctions since 2017, almost 80% of new-build gas-fired capacity which secured agreements was sized below 300 MW.[27] In addition, through DR we are proposing to introduce the option to comply with the requirements through hydrogen conversion as well as CCUS retrofit. Hydrogen conversion is expected to be more economically viable for the decarbonisation of smaller plants than CCUS.

We are therefore proposing to simplify requirements by removing the 300 MW threshold, as part of the update of CCR.

3.2.2 Summary of call for evidence responses

Call for Evidence Question 3:

What are your views on the 300 MW threshold, and what challenges might the removal of the threshold present to developers?

There were 32 direct responses to Question Three with eleven supporting a reduction of the current threshold and 20 supporting complete removal. There was clear feedback that market distortion is a perceived issue, however there was some caution raised in reducing the threshold as it could potentially introduce new forms of market distortion by incentivising the deployment of plants just below the new threshold, as we have already seen for the 300 MW threshold. Within the comments supporting threshold reduction, there was no general agreed consensus on a proposed lower threshold limit other than proportionality needing to be taken into account within the guidance relative to environmental permitting. Within these comments there was suggestion of possible phasing or lowering of DR requirements relative to plant size and capacity, specifically development between 10 MW to 100 MW. Comments related to these smaller assets underlined possible constraints concerning space requirements, technology devolvement and onerous regulation relative to their small scale. Conversely within the overall responses there was some agreement that levelling DR requirements and thresholds would support net-zero objectives. There were two comments that possible exemptions be considered for small plant operations (typically <20 MW).

There were five comments supporting exemptions for emergency back-up and Black-Start sites. Rationale for these exemptions were cited as; (a) the economic feasibility due to cost, available space and proximity to residential & urban areas, and (b) the purpose of emergency backup plant being focussed on capacity rather than generation volume, therefor resulting in lower emissions by design.

3.2.3 Proposal

We propose to completely remove the 300 MW threshold, in line with feedback on the call for evidence. We do not wish to create a lower threshold as this has the potential to create further market distortions, and excluding smaller plants which are, in aggregate, making significant contributions to our carbon emissions.

As we are also proposing to implement DR through environmental permitting (see Section 4), in practice the removal of the 300 MW threshold means that we are proposing that the DR

[27] Source: Capacity Market Registers as of April 2022, https://www.emrdeliverybody.com/CM/Registers.aspx

requirements would apply to all combustion power plants which are covered by the permitting regime, except those which are exempt from DR (see Section 3.5) or already have CCUS fitted or have already been converted to hydrogen. To minimise additional burdens, we do not propose to require any plants that would not otherwise be required to have an environmental permit to comply with the DR requirements. For reference, below we have set out the scope of the environmental permitting regime for combustion power plants, alongside a reference to the relevant section of the EPR.

- Those that form part of another installation which is permitted,[28] e.g. an industrial site (Schedule 1, Part 1).
- Those sized over 50 MW (Schedule 1, Part 2, Chapter 1, SECTION 1.1, Part A(1)).
- Those burning any fuel in a boiler, furnace, gas turbine or compression ignition engine sized 20 – 50 MW (Schedule 1, Part 2, Chapter 1, SECTION 1.1, Part B).
- Those sized smaller than 3 MW and burning any waste oil (Schedule 1, Part 2, Chapter 1, SECTION 1.1, Part B).
- Those sized below 50 MW[29], that hold a capacity agreement or an agreement to provide balancing services (Schedule 25B). This includes mobile generators which are connected to electricity transmission or distribution networks[30].
- Incineration plants with a capacity exceeding 10 tonnes per day (hazardous waste) or 3 tonnes per hour (non-hazardous waste) or those that incinerate any gaseous compound containing halogens[31] (Schedule 1, Part 2, Chapter 5, SECTION 5.1, Part A(1)).
- Small waste incineration plant - with an aggregate capacity of 50kg or more per hour of certain wastes[32] (Schedule 1, Part 2, Chapter 5, SECTION 5.1, Part B(a)) or with a capacity less than 10 tonnes per day (hazardous waste) or 3 tonnes per hour (non-hazardous waste) (Schedule 13).
- Those used for back-up[33] that are operated for the purpose of testing for no more than 50 hours per year (Schedule 25B 2(2)). And sized between 1 - 50 MW (Schedule 25A). These plants are permitted to operate less than 500h per year on a 5-year rolling average, but do not have to comply with air quality limits. (Schedule 25A, Part 2, 7(1) and 8(1)).
- Those used for back-up on islands (Schedule 25A, Part 2, 7(2)) that were put into operation before 20 December 2018[34] and are operated for the purpose of testing for no more than 50 hours per year (Schedule 25B 2(2)) and sized 1-50 MW (Schedule 25A). These plants are permitted to operate less than 1000h per year on a 5-year rolling average, but do not have to comply with air quality limits (Schedule 25A, Part 2, 7(2)).

[28] Described as a Directly Associated Activity to a Scheduled Activity.
[29] When aggregated – see the legislation for details.
[30] Or other apparatus, equipment or appliances at a site, and is not performing a function that could be performed by a generator that is not mobile.
[31] Other than incidentally in the course of burning landfill gas or solid or liquid waste.
[32] See the legislation for further details.
[33] This means a generator operated for the sole purpose of maintaining power supply at a site during an on-site emergency.
[34] Or for which an environmental permit was granted before 19th December 2017, provided that the plant was put into operation no later than 20th December 2018.

Consultation Question 4:

Do you agree with our proposal to remove the 300 MW threshold and to align the scope of decarbonisation readiness with the existing scope of environmental permitting for combustion power plants?

3.3 New and refurbishing combustion power plants

3.3.1 Background

We do not propose to include existing power plants in DR, as this could interfere with the important transitional role of our existing gas capacity. But we are inclined to include substantially refurbishing power plants in the scope of DR, in addition to new build. This will eliminate the risk of unintentionally incentivising developers to pursue refurbishing existing projects as a way of avoiding the DR requirement. As part of this, we need to consider how to identify refurbishing power plants within scope, as there may be a grey area between routine maintenance and refurbishment which extends the lifetime of a plant. Existing power plants that have already been through the CCR process will be required to continue submitting progress reports, as currently required by the CCR Regulations 2013, see Section 5.

3.3.2 Summary of call for evidence responses

Call for Evidence Question 4:

What are your views on the inclusion of refurbishing plant in DR? How could we best define refurbishing plant in this context?

We received 31 direct responses to Question Four with one uncertain, seven understanding the need and 23 directly supporting the inclusion of refurbishing plant in DR. A majority of respondents thought that it would be acceptable to use the definition of ‘substantial refurbishment’ from the Environmental Permitting (England and Wales) Regulations 2016 to define refurbishing plant for the purpose of DR. A few respondents suggested that the capital expenditure thresholds in the CM could also be used to define refurbishing plants for DR. There was general concern to ensure that refurbishing plants be clearly defined.

3.3.3 Proposal

We propose to include both new build and substantially refurbishing combustion power plant within scope of the DR requirements.

Regarding new build, we propose that this should cover all relevant plants (i.e., those which are covered by environmental permitting and are not exempt) that will be put into operation after **1 July 2024** – the proposed implementation date for DR. Our proposals on transitional arrangements, for plants that are already in process of being built are set out in Section 3.5.

Regarding refurbishing plant, Government proposes to use the existing definition of ‘substantially refurbished’ to define refurbishing plant, which is set out in Schedule 24 to the

Environmental Permitting (England and Wales) Regulations 2016.[35] In the definition, substantially refurbished means a refurbishment the cost of which exceeds 50% of the investment cost for a new comparable energy plant. We believe that this strikes the correct balance of ensuring that existing plants which carry out substantial refurbishments are covered by DR, whilst enabling existing plants to carry out routine maintenance without having to meet DR requirements. And conveniently, it is already housed in the legislation through which we propose to implement DR. We would review this definition as part of the regular reviews of DR (see Section 5.2) to ensure that it continues to strike the right balance.

As for new build plants, DR requirements would apply to relevant (i.e. those which are covered by environmental permitting and are not exempt or under a transitional arrangement) substantially refurbishing plant put back into operation (or completing their refurbishing works) after **1 July 2024**.

In addition to the requirements for new build and substantially refurbishing plants, we propose to enable existing plants which are not substantially refurbishing to voluntarily submit a DR report to the EA. As outlined in Section 2, Government is determined to remove barriers to the decarbonisation of high carbon combustion power plants where possible. We recognise that developers of plants which are built prior to the updated DR requirements coming into force may wish to demonstrate their plant's decarbonisation potential. We see this particularly for plants with long term CM agreements which may be unable to decarbonise within their existing CM agreement. A DR report outlining there are no known barriers to the plant's decarbonisation could enable the developer to demonstrate their decarbonisation potential and provide them with access to possible decarbonisation routes in future.

In January 2023, we published a CM consultation[36] which sought views on establishing a pathway to enable unabated generators to exit an existing multi-year CM agreement in order to access a new CM agreement or alternative support schemes in order to decarbonise, subject to ensuring continued security of supply and certain conditions being met. This could provide CM agreements holders with a route to demonstrating their decarbonisation potential, opening up decarbonisation pathways for existing capacity.

A voluntarily submitted DR report would be treated in the same way as a new build or substantially refurbishing one, with the EA assessing the report and if the tests are satisfactorily met, a DR permit issued. Developers which follow this route would be required to comply with all DR requirements going forward.

Consultation Question 5:

Do you agree with our proposals to include both new build and substantially refurbishing plant within scope of DR? What are your views on using the definition of "substantially refurbishing" from the environmental permitting legislation in the context of DR?

Consultation Question 6:

Do you agree with enabling existing plants to voluntarily submit a DR report?

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[35] https://www.legislation.gov.uk/uksi/2016/1154/contents/made
[36] https://www.gov.uk/government/consultations/capacity-market-consultation-strengthening-security-of-supply-and-alignment-with-net-zero

3.4 Types of power plants covered by Decarbonisation Readiness

3.4.1 Background

The mix of electricity generation technologies in GB has changed significantly since 2009. For example, there is no longer the prospect of new coal-fired and oil-fired power plants being built. Furthermore, given the net zero imperative, it is necessary to consider whether additional types of combustion power plant should be captured by the DR requirements such as energy from waste, biomass and combined heat and power (CHP). This will also make the requirements simpler and more consistent across technology types. These plant types were previously implicitly excluded from the scope of the CCR requirements due to their size and improved environmental performance compared to unabated fossil fuel combustion power plants. There is also a case for including heat-only combustion plants in DR, particularly if the proposals are implemented through environmental permitting, which already applies to both heat and power combustion plants.

3.4.2 Summary of call for evidence responses

Call for Evidence Question 5:

What are your views on the potential inclusion of technologies such as heat, energy from waste, biomass and CHP in DR? Are there are any additional technologies to these which could be included?

There were 33 direct responses to Question Five with the majority supporting the inclusion of all relevant technologies including biomass, energy from waste, CHP and heat plants. Some respondents were concerned about including technologies that may already be seen as low carbon, such as biomass, in case this curtailed their deployment.

3.4.3 Proposal

3.4.3.1 Biomass

At this time, we propose to include all biomass electricity generation combustion technologies (except plants burning landfill gas and some energy from waste plants - see next section) in DR which would already require an environmental permit, including plants which burn biogas produced from anaerobic digestion which are already required to have a permit.[37] This will ensure that any new build or substantially refurbishing unabated biomass plants which come forward are able to convert to CCUS in the future. Whilst sustainable biomass is already a low carbon technology, bioenergy with carbon capture and storage (BECCS) presents the opportunity to deliver negative emissions and low carbon power generation. On 4 November 2021, Government published a Biomass Policy Statement, which noted that power BECCS is likely to significantly contribute towards our Net Zero ambition of 5MtCO2/year of engineered greenhouse gas removals by 2030.[38] In August 2022, the Department also published a consultation on business models for power BECCS.[39] Inclusion of biomass in DR will help to

[37] This would not include certain small anaerobic digestion plants which are used to treat waste, which are exempt from environmental permitting under the T24 and T25 waste exemptions.
[38] https://www.gov.uk/government/publications/biomass-policy-statement-a-strategic-view-on-the-role-of-sustainable-biomass-for-net-zero
[39] https://www.gov.uk/government/consultations/business-model-for-power-bioenergy-with-carbon-capture-and-storage-power-beccs

prepare the sector for BECCS, in the event that any further biomass plants are built or substantially refurbished without CCUS.

3.4.3.2 Energy from waste

In line with the view of the majority of respondents to the call for evidence, we propose to include in DR combustion energy from waste (EfW) plants which would already require an environmental permit and be permitted by the EA. This would cover conventional incineration plants and plants and combustion plants producing electricity by burning fuel products which have been produced from waste through Advanced Thermal Treatment (ATT)/Advanced Conversion Technology (ACT) such as gasification and pyrolysis.

Whilst the EfW sector is relatively small, we expect that it will represent a significant proportion of residual emissions from the power sector in the 2030s, as other forms of generation are rapidly decarbonised. It is therefore important that it is targeted with emissions reduction policies. The inclusion of EfW in DR will also ensure strategic fit with other initiatives to decarbonise the EfW sector, including the proposed expansion of the UK Emissions Trading Scheme (UK ETS) to energy from waste,[40] and the enabling of waste management CCUS projects to be eligible for support through the Industrial Carbon Capture (ICC) business model for Phase-2 of the cluster sequencing process.[41]

We understand that the primary function of EfW is waste management. EfW developers must make additional considerations compared to the developers of traditional electricity generation projects, regarding the availability of waste feedstocks. We believe that the DR requirements as proposed in this document, with the economics and location assessments being non-mandatory, would not significantly constrain the deployment of EfW to the extent where it would impact waste management. The DR requirements provide an important signal for decarbonisation of the sector to help meet our ambitious net zero target.

We propose to exclude small waste incineration plants and plants burning landfill gas from DR, even if they are required to have an environmental permit (see Section 3.5 for details).

3.4.3.3 Combined heat and power

We propose to include CHP plants which would already require an environmental permit in DR. This will help to incentivise new build and substantially refurbishing CHP plants to further decarbonise, which we expect will be required in order to reach net-zero – as outlined in our 2021 call for evidence on CHP.[42]

3.4.3.4 Heat

We are not currently proposing to include combustion plants which only produce heat in DR. However, we are open to adding these plants into DR at a later date, in order to support the decarbonisation of heat.

In this regard, we published the Government response to the call for evidence on hydrogen readiness for industrial boilers in December 2022.[43] We intend to sponsor the British

[40] https://www.gov.uk/government/consultations/developing-the-uk-emissions-trading-scheme-uk-ets
[41] https://www.gov.uk/government/publications/carbon-capture-usage-and-storage-ccus-business-models/november-2021-updates-on-the-industrial-carbon-capture-and-dispatchable-power-agreement-business-models
[42] https://www.gov.uk/government/consultations/combined-heat-and-power-pathway-to-decarbonisation-call-for-evidence
[43] https://www.gov.uk/government/consultations/enabling-or-requiring-hydrogen-ready-industrial-boiler-equipment-call-for-evidence

Standards Institution to ensure that hydrogen-ready industrial-sized boiler equipment is covered by a Publicly Available Specification (PAS). DESNZ will also continue to assess the merits of requiring large boilers to be hydrogen-ready including through product regulation, environmental permitting, or a combination of the two.

Consultation Question 7:

Do you agree with our proposals to include biomass, EfW and CHP in DR?

Consultation Question 8:

What are your views on including heat generation in DR at a later date?

3.5 Exemptions and transitional arrangements

3.5.1 Background

We are considering exemptions from DR, to ensure that DR is not applied to plants where it would be disproportionate or ineffective to do so given the purpose of the plant.

We are also considering whether to apply transitional arrangements for DR, for plants which are in the process of construction at the time when the requirements come in to ensure that investment confidence is preserved.

3.5.2 Summary of call for evidence responses

Call for Evidence Question 6:

What are your views on potential exemptions from DR? Would it be suitable to exclude plant which operate below a certain level of annual carbon emissions and/or running hours?

Call for Evidence Question 7:

Beyond exempting plants from DR which obtain a Capacity Markets agreement before DR is implemented, is there anything more that we could do to ensure that the DR requirements do not affect the Capacity Market?

Concerning Question Six, there were 31 direct responses with a large majority supporting exemptions for certain plant types. There was general support for exemptions for several variations of asset types, in particular those used for back-up purposes.

There were 25 direct responses to Question Seven with a majority supporting an alignment of the Capacity Market with DR. Beyond exempting plants from DR which obtain a CM agreement before DR is implemented, no further suggestions were made to reduce impacts on the CM. It was noted by several respondents that the CM's current design risks locking-in unabated forms of electricity generation beyond 2035.

3.5.3 Proposal – Exemptions

Almost all new build and substantially refurbishing combustion power plants are required to obtain an environmental permit. The permitting of combustion power plants sized below 50 MW is driven by air quality legislation – stemming from the Medium Combustion Plant Directive

(MCPD) and additional air quality controls for generators, which were implemented by Defra in 2017.[44] A lot of work was done with industry at the time to agree the scope of this legislation, including exemptions. As we are proposing to implement DR through environmental permitting (see Section 4), regarding exemptions we therefore propose to broadly follow the scope of the air quality legislation – i.e. we broadly propose to only require combustion power plants which would already require an environmental permit to have to comply with DR, with a few exceptions (listed further below). For reference, the following combustion power plants are not required to have an environmental permit and are therefore not proposed to have to comply with DR:

- Those sized below 50 MW installed on an offshore platform, or a gas storage or unloading platform[45] (Schedule 25A, Part 1, 2(1) and Schedule 25B, 2(2)).
- Those that are sized below 50 MW that are mobile,[46] except where they are connected to electricity transmission or distribution networks[47] (Schedule 25A, Part 1, 2(1) and Schedule 25B, 2(2)).
- Those sized below 1 MW that do not have a CM agreement or an agreement to provide balancing services (Schedule 25B, 2(1)).
- Those sized below 1MW, operating with a defined nuclear safety role under a nuclear site licence issued by the Office for Nuclear Regulation (Schedule 25B (2(2)) and Schedule 25A).
- Small anaerobic digestion biogas plants used to treat waste, under the T24 and T25 waste exemptions[48].

In addition to the above combustion power plants, which would be automatically exempt if we only required combustion power plants which would already require an environmental permit to comply with DR, we also propose to exempt the following combustion power plants – which are required to be permitted:

- Plants of any size burning landfill gas. Landfill sites produce methane from decomposing organic material. The capture of this gas and treatment through a landfill gas engine is the best option for its management, as methane is a much more potent greenhouse gas than CO_2. Including landfill gas plants in DR could create a disincentive to newly building or substantially refurbishing a landfill gas engine. That in turn could then result in the methane emissions from a landfill site being unmanaged, causing a net increase in emissions, which would contradict the overall aim of DR. Furthermore, as set out in the Net zero Strategy,[49] Government is committed to exploring options for the near elimination of biodegradable municipal waste to landfill from 2028. Therefore, the amount of landfill gas being produced from landfill sites is expected to decline significantly over the coming decades. For this reason, it is not likely that further new build or substantially refurbishing landfill gas engines will come forward, as there is unlikely to be a source of landfill gas available for long

[44] https://www.gov.uk/guidance/medium-combustion-plant-and-specified-generators-environmental-permits
[45] Terms are defined in the legislation.
[46] Means designed to move or be moved whether on roads or other land. These are covered by the NRMM regulations https://www.legislation.gov.uk/uksi/2018/764/made.
[47] Or other apparatus, equipment or appliances at a site, and is not performing a function that could be performed by a generator that is not mobile.
[48] https://www.gov.uk/guidance/waste-exemption-t24-anaerobic-digestion-at-premises-used-for-agriculture-and-burning-resulting-biogas and https://www.gov.uk/guidance/waste-exemption-t25-anaerobic-digestion-at-premises-not-used-for-agriculture-and-burning-resulting-biogas
[49] https://www.gov.uk/government/publications/net-zero-strategy

enough to justify such an investment. But nonetheless, the exemption will ensure that DR does not create a barrier to such engines being newly constructed or substantially refurbished where it is viable to do so, in order to manage fugitive methane emissions.

- Small waste incineration plant - with an aggregate capacity of 50kg or more per hour of certain wastes[50] (Schedule 1, Part 2, Chapter 5, SECTION 5.1, Part B(a)) or with a capacity less than 10 tonnes per day (hazardous waste) or 3 tonnes per hour (non-hazardous waste) (Schedule 13). These are very small sites and are permitted by local authorities, who do not have the expertise or capacity to assess DR.

- Those used for back-up[51] that are operated for the purpose of testing for no more than 50 hours per year (Schedule 25B 2(2)). And sized between 1 - 50 MW (Schedule 25A). <u>These plants are permitted to operate less than 500h per year on a 5-year rolling basis, but do not have to comply with air quality limits</u> (Schedule 25A, Part 2, 7(1) and 8(1)). These plants are not subject to any other environmental restrictions, so it would not be proportionate to apply DR to them.

- Those used for back-up on islands that were put into operation before 20 December 2018[52] and are operated for the purpose of testing for no more than 50 hours per year (Schedule 25B 2(2)). And sized 1-50 MW (Schedule 25A). <u>These plants are permitted to operate less than 1000h per year on a 5-year rolling, but do not have to comply with air quality limits</u> (Schedule 25A, Part 2, 7(2)). These plants are not subject to any other environmental restrictions, so it would not be proportionate to apply DR to them.

We acknowledge that some existing combustion power plants sized below 50 MW won't be covered by permitting until 2025 or 2030 as this is when air quality limits come into force, and therefore would not be captured by DR until these dates if they were to substantially refurbish. We do not propose to include such plants in DR before their permitting date, given the limited number that may be expected to substantially refurbish before 2025/2030.

3.5.4 Proposal – Transitional arrangements

There is a clear case for exempting plants from DR which are under construction or substantial refurbishment at the time the DR requirements are proposed to come in (1 July 2024). The developers and investors did not have visibility of the DR requirements when they took their investment decisions and as such should not be held to them.

In order to exempt these plants, we need to consider how to define 'under construction'. It cannot be assumed that plants which already have planning consent are actively under construction, as we know that there are tens of GWs of combustion power plants which have been consented but will probably never be built, as the plans to build have likely been abandoned by developers. If we were to exempt these plants, then it would create an incentive for developers to revive old, abandoned projects in order to avoid DR requirements. This could significantly diminish the impacts of the policy and create distortions and unfairness in the project development market.

Our proposal for confirming whether a project is truly 'under construction' is to check whether the site holds a CM agreement at the time that DR requirements would come into force (<u>**1 July**</u>

[50] See the legislation for details.

[51] This means a generator operated for the sole purpose of maintaining power supply at a site during an on-site emergency.

[52] Or for which an environmental permit was granted before 19th December 2017, provided that the plant was put into operation no later than 20th December 2018.

2024). Having a CM agreement should confirm that the project is under active construction / refurbishment, as once these are signed, there is a strong incentive for completing the works and a clear end date.

Therefore, the 2024 CM auctions (typically held in the first quarter of the year) would be the last chance for plants to secure a CM agreement before the DR requirements come in.

As part of moving DR to environmental permitting (see Section 4) we are proposing to remove the existing CCR requirements from the planning regime in England. We are not aware of any active new build or refurbishing projects which will have been through the CCR process by 1 July 2024 and are not expected to also attain a CM agreement before this date (thereby being exempt from DR). Therefore, we cannot presently see the need for any additional transitional provisions outside of the one for CM agreement holders. But we would welcome views from stakeholders on whether any additional transitional provisions may be needed.

Consultation Question 9:

Do you agree with our proposed approach to exemptions from DR requirements?

Consultation Question 10:

Do you agree with our proposed approach to transitional arrangements from DR requirements?

4. Moving Decarbonisation Readiness to the Environmental Permitting Regime

4.1. Background

Currently the Carbon Capture Readiness (CCR) requirements are applied through the Development Consent Order (DCO) process for Nationally Significant Infrastructure Projects (NSIPS). The Carbon Capture Readiness (Electricity Generating Stations) Regulations 2013 ("CCR Regulations 2013") establish that new combustion power plants at or above 300 MW must demonstrate that it will be technically and economically feasible to retrofit carbon capture technology within the lifetime of the plant as a condition of receiving their DCO.[53] The 2009 CCR guidance supplements the principles of CCR, as set out in the CCR Regulations 2013, with details of how technical and economic feasibility should be assessed by developers, the detailed requirements of CCR reports, and how CCR reports are assessed by DESNZ with support from the Environment Agency (EA) and Natural Resources Wales (NRW) as part of the consenting process.[54]

There are many advantages to applying the Decarbonisation Readiness (DR) requirements through the environmental permitting regime (as implemented by the Environmental Permitting Regulations), compared to the DCO process, as set out below. Consolidating the requirements

[53] https://www.legislation.gov.uk/uksi/2013/2696/made

[54] https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/43609/Carbon_capture_readiness_-_guidance.pdf

into the Environmental Permitting Regime (EPR), which already houses other environmental requirements, should lead to overall simpler regulatory requirements. Due to these advantages, we are considering moving the application of the DR requirements out of the planning regime and into environmental permitting.

- If we continued to apply the DR requirements through the DCO process it could create an incentive for developers to return to previously abandoned projects that have already received planning consent, rather than new projects, to avoid the DR requirements. This could diminish the impacts of DR and distort the market for developers.

- Planning consents for plants below 50 MW in England are dealt with by local authorities. Plants above 50 MW are consented by the Secretary of State. Therefore, if the 300 MW threshold were to be removed from DR but DR still implemented through planning law, then local authorities would become responsible for reviewing and approving DR demonstration for plants below 50MW. This could create issues for some local authorities depending on their capabilities, resourcing and expertise, particularly as there may be a large number of planning applications for smaller combustion power plants. In comparison, the EA are already involved in the assessment of CCR requirements and have the technical expertise to assess DR demonstration. At present, when a planning consent application is made it goes to the Planning Inspectorate, who then request views from the EA on the CCR element of the overall application.

- Most new build power plants in the UK are already required to have environmental permits in place in order to operate. Operators and investors are therefore well versed in the Environmental Permitting process, making a transition from planning easier.

- Environmental Permitting is a more flexible regime than planning and so will allow the EA to update and amend the requirements more readily, as technology and policy develops. Tried and tested systems are already in place for compliance monitoring, inspection and audit, reporting and enforcement, and paying permitting fees and charges.

Despite the numerous benefits of implementing through environmental permitting, there are some drawbacks:

- There is no requirement for an environmental permit to be granted before a DCO is granted for a site. Moving the DR requirements to environmental permitting may therefore create a risk whereby developers must decide, for example, how much space should be set aside to accommodate additional equipment needed for carbon capture or hydrogen-firing in the future and lock this in through their DCO, before having formal confirmation from the EA that this is sufficient to meet their DR requirements. However, similar risks already exist (e.g. decisions on stack height linked to air quality requirements) and to mitigate them, developers are encouraged to pursue such considerations linked to their applications for an environmental permit and planning consent in parallel, in order to minimise issues around alignment. In addition, whilst it would no longer be a DCO requirement in law, it will remain a relevant consideration in the planning decision and it is a straightforward matter for the planning inspectorate to make enquiries of the developer on this point, as they already do on other matters dealt with through EPR, and to include this in their planning report.

- Implementing through EPR may increase investors perception of risk, due to the possibility of changes to future permit requirements, thus making projects more expensive. Any additional cost would ultimately fall to consumers, due to increased prices in the Capacity Market and other energy markets. However, similar risks already exist and are managed by developers and investors.

4.2 Summary of call for evidence response

Call for Evidence Question 8:

What are your views on implementing DR through environmental permitting rather than the planning consent process?

Call for Evidence Question 9:

If we were to implement DR through environmental permitting, how can developers be given confidence that their site will be compliant with DR prior to construction?

Question Eight resulted in 32 direct responses with a large majority supporting a shift of DR to Environmental Permitting. There was overall concern for availability of resource and capacity within the Environment Agency and Natural Resources Wales to deliver on time giving assurance and clarity to the process and to developers.

There were 28 direct responses to Question Nine with a consensus that clear concise guidance would be beneficial, as well as committed timeframes being adhered to. The possibility of a pre-application process was raised.

4.2.1 Proposal

In line with the majority of respondents to the call for evidence, we propose to implement the requirements through environmental permitting. To mitigate the risk of any discrepancies between planning consents and permit requirements, we encourage developers to attain their environmental permit in parallel to the consenting and construction of the site. We believe that any increase to investors' perception of risk resulting from implementing through environmental permitting should be manageable, given that DR is being targeted at new build and refurbishing plants only, which would already have to seek a new or variated environmental permit. And any substantive changes to DR would of course require further consultation. We do welcome feedback on any potential impacts on the planning system arising from the proposal.

With regards to the resourcing and capacity of the EA, DESNZ has agreed to provide the EA with transitional funding support to gear up their systems and capacity ahead of 1 July 2024. This should help to alleviate any issues.

As set out in section 3.1, DR will only apply in England. Therefore, when implementing DR through environmental permitting, we will revoke the existing CCR requirements related to planning – implemented through the CCR Regulations 2013 – in England only. The existing CCR requirements will continue to apply in Scotland and Wales.[55]

Consultation Question 11:

Do you have any comments on our proposal to move the DR requirements to the environmental permitting regime?

[55] https://www.legislation.gov.uk/uksi/2013/2696/made

Consultation Question 12:

How do you see the proposed changes impacting the planning system (Nationally Significant Infrastructure Projects (NSIP) and/or Town and Country Planning Act (TCPA) regimes), including decision, and plan-making?

4.3 Appeals Process for Decarbonisation Readiness

4.3.1 Background

Government recognises that the proposed update of the DR requirements bring more combustion power plants into scope alongside the proposal to move the requirements into the environmental permitting regime could place additional pressures on developers to ensure compliance. Given the updated scope of DR and the importance in plants coming forward to ensure security of supply Government recognises the need for developers to have a route to appeal decisions should their plant be denied a permit.

We note that Chapter Five of Part 2 of the Environmental Permitting (England and Wales) Regulations 2016 enables those applying for or subject to environmental permitting to appeal to the appropriate authority.[56]

4.3.2 Proposal

To minimise the introduction of additional regulations, we do not propose to introduce further appeals processes beyond those currently outlined in Chapter Five of the Environmental Permitting (England and Wales) Regulations 2016.

Consultation Question 13:

Do you agree with our proposed approach to DR appeals?

5 Reviewing Decarbonisation Readiness

5.1 Two-yearly reviews of plant's compliance

5.1.1 Background

Under the current 2009 Carbon Capture Readiness (CCR) guidance, developers are required to submit a review report within three months of the commercial operation date of the plant and every two years thereafter, continuing until such time as the developer retrofits carbon capture technology to their plant. Developers are required to submit the reports outlining whether it remains technically feasible to retrofit carbon capture technology to the plant and to inform Government of any technical barriers to retrofitting which may have emerged since the original consent was granted.

[56] https://www.legislation.gov.uk/uksi/2016/1154/part/2?view=plain

5.1.2 Summary of Responses

Call for Evidence Question 10:

What are your views on the two-yearly review of DR requirements? Should this be retained and is the frequency suitable?

29 responses were received for Question Ten with the majority of respondents supported the principle and proposed term for developers to review their plants' Decarbonisation Readiness (DR) compliance. Those in favour of the review principle highlighted the need for plants to regularly assess performance and the changes associated with implementing DR, and the need to meet net zero necessitating ongoing review and drive.

13 respondents suggested different review periods covering one to five years with those suggesting longer periods noting that it would be unlikely that technology would change substantially within two-year cycles, or that a developer would be unlikely to make meaningful changes to their plant within this time. Respondents also noted that extending the review period would minimise administrative burden. Alignment to other processes and regulated reviews were cited as key considerations in any review design.

Possible optional review triggers were also proposed to include: a) the review itself only be triggered following commissioning; b) that reviews be triggered outside the final agreed review period upon consenting and / or construction of localised decarbonisation infrastructure, perhaps incorporating a checklist of potential external factors which impact plant operations to enable and inform pathways; c) that the identification of barriers within the review report trigger a requirement on the developer to demonstrably evidence processes and engagement to identify solutions to those barriers; and, d) a need to further identify what triggers would or could initiate more detailed reviews relative to continued compliance.

5.1.3 Proposals

The Government intends to maintain current regulatory expectations and continue with the current CCR regulation to require developers to review their requirements every two years after the permitted plant begins commercial operation. We expect the infrastructure and technologies for both hydrogen and CCUS to rapidly increase and mature over the coming years, particularly in the 2030s. It is therefore important developers are regularly reviewing their plant's compliance with DR requirements and assessing whether a viable decarbonisation option has become available, for example, the connection of a nearby industrial area to a hydrogen network.

Developers should also be able to update their proposed approach to meeting DR requirements in light of new technological or economic developments, or wider infrastructure changes such as the installation of hydrogen or CCUS T&S infrastructure close to their plant. We propose these changes could be made with evidenced justifications. The EA should consider such justifications and may allow appropriate modifications. They would also be able to use the review to inform the EA of a change of decarbonisation technology, and evidence demonstrating that the DR requirements for the alternative technology have been met.

If the two-yearly review identifies a barrier to retrofitting the developer's chosen decarbonisation technology, this should not be treated as non-compliance with the permit. Both hydrogen and CCUS are evolving technologies and a technical solution may emerge in time. Developers, however, should consider any identified barrier carefully and explore solutions accordingly. The review would only lead to a developer being considered in breach of their permit if any action they had taken had led to the emergence of the barrier, for example, if they fail to maintain control of the space set aside for carbon capture equipment or equipment associated with hydrogen storage or transport.

As the hydrogen and CCUS economies and infrastructure expand, it will be important for Government to gather information pertaining to forthcoming plans for its use and expansion to inform policy decision making. The two-yearly reports submitted by developers will also be useful for Government in supporting this.

Although applications for environmental permits and planning consent may be carried out in parallel, we anticipate that environmental permits may typically be issued closer to the point of combustion plant operations commencing rather than closer to the original planning consent, as is currently the case with CCR requirements. This reduces the importance of the progress report that is currently required to be submitted (under the CCR Regulations 2013) three-months after the commencement of operation. We therefore we propose to remove the three-month report in future DR requirements, and the first report from developers would be due two years from when eligible combustion power plants are put into operation.

Government recognises the two-yearly review places requirements on developers; however, the review process will be relatively light touch focusing on reviewing the most significant aspects of DR requirements to ensure developers are in the best position to maximise decarbonisation opportunities as the wider CCUS and hydrogen economies expand. The details of the assessment would be outlined in the DR guidance issued by the EA, but we expect this would include assessing whether viable transport and storage infrastructure is being developed close to the plant, and whether the chosen technology remains the most suitable decarbonisation option.

We propose to include the two-yearly requirement for a report within a 'Decarbonisation Readiness' schedule added to the EPR.

Existing power plants that have already been through the CCR process will be required to continue submitting progress reports, as currently required by the CCR Regulations 2013. This requirement will be retained.

The regular reporting requirement would fall away (as would all DR requirements) if a plant were to retrofit CCUS equipment or convert to firing 100% hydrogen.

Consultation Question 14:

Do you agree with the proposal for developers of eligible plants to submit update reports every two years from the start of their combustion power plant's operations? What are your views on what the report should cover?

5.2 Government review of Decarbonisation Readiness requirements

5.2.1 Background

Both hydrogen and CCUS are rapidly evolving in terms of technology, economics, and how they sit within the energy policy landscape. As outlined in Section 2.2, Government is actively supporting the development and expansion of these technologies. These changes will likely have an impact on how the proposed DR assessments can be applied, and indeed, additional decarbonisation technologies may emerge which could offer alternative routes for combustion power plants to decarbonise in future, e.g. ammonia as a fuel. It is important, therefore, for Government to regularly review the DR requirements to ensure they remain effective, fit for purpose, and are meeting the objectives of DR proposed in Section 2.4.

It will also be important to balance the need for guidance which keeps pace with technical and economic developments against a desire for regulatory stability and resource considerations of undertaking the review.

5.2.2 Summary of responses

Call for Evidence Question 11:

How frequently should the DR requirements be reviewed? Should this be made a legislative requirement?

Question Eleven received 29 responses with 13 supporting a five-year review period and ten responses supporting review periods of one, two, and four years. The rationales for more frequent reviews included keeping pace with the rapid development of emerging technologies and ensuring pathways to net zero.

Respondents highlighted several rationales in favour of a longer review period between four and five years including: a) reducing the risk of possible frequent changes and / or retroactive requirements within the Decarbonisation Readiness process; b) to keep a balance between policy, stability and technical progress of decarbonisation solutions (particularly relative to Net Zero prioritisation); c) to keep pace with technological change, development and deployment timescales (both short and long term); d) to allow for meaningful change such as technological innovation and viability; e) aligning the review process with that of the CM reviews to ensure consistency (or at least as part of the CM annual change cycle); and, f) that of taking the pre-application, permitting and consenting process into account due to the longer time frames involved within those processes.

There were eleven responses in support of making the re.view a legislative requirement on Government, with no comments against.

5.2.3 Proposals

Government notes Regulation 80 of the EPR which in relation to England, requires the Secretary of State to from ‘time to time’ carry out a review of the regulatory provisions in the EPR, and to publish a report setting out the conclusions of the review.[57] The report should set out the objectives intended to be achieved by the regulatory provisions and assess the extent to which the objectives are achieved, and whether the objectives remain appropriate. The first report must be published at intervals not exceeding five years.

Regulation 80(1) would allow DR to be reviewed against its proposed objectives (see Section 2.4) and enable a wider assessment of the requirements effectiveness at intervals not exceeding five years. This could form part of the wider report on the EPRs, or be decoupled and carried out separately, if this were to better suit the review needs of DR. This could include assessment of the effectiveness of the four assessments for each technology, notably whether economic feasibility and the hydrogen fuel access test should be made mandatory to pass, and

[57] https://www.legislation.gov.uk/uksi/2016/1154/regulation/80/made

whether any new technologies have emerged which could offer alternative decarbonisation pathways for power plants (e.g. ammonia as a fuel). A proposed summary of the review's scope is outlined below:

- To assess how DR has performed against its objectives.
- Do the DR objectives remain appropriate?
- Does the legislation remain appropriate?
- Should the hydrogen fuel access test be made mandatory to demonstrate?
- Should the economic tests for hydrogen and/or CCUS readiness be made mandatory to demonstrate?
- Suitability of the Regulator's guidance.
- The costs of implementing the policy, as compared to the forecasted costs.

The requirement that there should be no more than five-year intervals in the review cycle would strike an effective balance between keeping pace with the rapidly evolving technologies of hydrogen and CCUS, whilst allowing meaningful change in those technologies which could inform potential amendments to the requirements. We also note that reviews and updates to the DR requirements could take place outside of the EPR report cycle to reflect wider accelerated or urgent market, policy, or technical developments. This approach will enable efficiencies in approach, whilst minimising the introduction of additional regulatory requirements. We would work closely with the EA to identify the need for and to deliver the reviews of DR.

Consultation Question 15:

Do you agree with our proposal for a regular review of Decarbonisation Readiness requirements as part of any review carried out and report published under regulation 80 of the Environmental Permitting Regulations 2016?

5.3 Future proofing Decarbonisation Readiness requirements

5.3.1 Summary of responses

Call for Evidence Question 12:

How can we future proof DR against further technological development, e.g. new decarbonisation technologies and/or simplify the process for adding new technologies to DR?

There were 27 responses received for Question Twelve with a majority consensus that any process for reviewing emerging technologies should be flexible, reviewed within an appropriate review period, and be relevant to updating of the DR guidance and legislation. Respondents also noted that the introduction of new technologies to the DR requirements should not pose retroactive mandates or barriers to currently committed assets.

Three comments were received which proposed that DR requirements focus more on emission reduction targets rather than specific technologies and methodologies, as the respondents' felt this was more appropriate to the desired outcome of DR. It was suggested that this approach would facilitate the most effective emission capture solutions relative to each plant and circumstance and in turn support changing and emerging technologies. Emission targets inclusive of CO_2, NOX levels and other possible pollutant outputs would enable choice on the part of the developer to propose technologies within the feasibility assessment and conceivably allow development and / or switching of those proposed methods during and as part of the periodic reviews.

5.3.2 Proposals

We recognise the need for any process for reviewing possible new decarbonisation technologies into the DR requirements to be as flexible and as simple as possible. Similarly, we recognise such a process should be clear and conducted within a prescribed and publicised period. We, therefore, are proposing a regular review of DR requirements proposed in Section 5.2 to include a review of potential new decarbonisation technologies in addition to hydrogen and CCUS by Government alongside a public consultation.

A comparable mechanism is conducted annually for the CM to consult on whether any new technologies, not already identified, which are capable of contributing to security of supply have emerged and should be eligible to participate in future CM auctions.[58] We need to balance the need for flexibility in suggesting new technologies with the pace of technological advancement. We therefore propose that the review process occurring regularly at intervals of no more than five years as opposed to the CM's annual review of new technologies is more appropriate.

Government notes the feedback on focusing DR requirements on emission threshold targets, however, our intention with DR is to encourage the full decarbonisation of combustion power plants. The use of emission threshold targets could encourage operators to focus on hitting the targets, rather than conversion to technologies which offer significant, or near total emission reductions.

5.4 Alternative decarbonisation options

5.4.1 Summary of responses

Call for Evidence Question 13:

Are there any alternative decarbonisation options, beyond low-carbon hydrogen and CCUS which are already developed enough to be included in Decarbonisation Readiness? If so, then please include details on how their readiness could be assessed for a combustion power plant.

Question 13 received 25 responses, three of which did not identify alternative options. 20 responses were supportive of including alternatives which they felt could meet the objectives of DR and could be included within the requirements. These included: development of Carbon Capture and Utilisation (CCU) (nine); bio gas/fuels (nine); biomass (seven); ammonia (six); BECCS (four); development of CCUS (four); fuel switching (three); CHP (three); renewable energy sources such as solar, heat pumps, wind and tidal all to differing degrees of scales (two), low carbon electrolytic hydrogen (two); biochar / biogenic (one); direct air capture (one), continuation of nuclear (one); indirect carbon capture (one); and alternative fuel cells other than Hydrogen (one).

[58] https://www.gov.uk/government/consultations/capacity-market-new-technologies-2021

5.4.2 Proposals

We note the proposed inclusion in Section 3.4 of biomass generation within the scope of DR requirements to support BECCS development. We also note that CHPs are proposed to fall within scope of the updated DR requirements as well, with Government intending for CHP readiness to remain in place for plants which have decarbonised to incentivise maximising efficiencies of generation technologies.

Government does not believe that the technologies for biochar, biogas, or ammonia are sufficiently advanced at this time to warrant inclusion as an alternative decarbonisation technology in DR requirements.

Conversion to renewable energy sources, whilst providing low carbon capacity, would not be replacing like for like capacity. Reaching our CB6 and net zero targets will require low carbon flexible capacity to be available when renewable output is lower. DR requirements are intended to drive the decarbonisation of dispatchable and flexible capacity, and so we are not minded to include conversion to renewable energy sources as a decarbonisation pathway.

We would not consider direct air capture or indirect carbon capture to be within the objectives of DR as they do not directly decarbonise power plants and their usage to achieve DR could create market distortions.

At this time, Government has therefore concluded that no technologies in addition to hydrogen and CCUS are sufficiently developed to be included in the DR requirements. We propose to include a specific item in the regular review of DR requirements proposed in Section 5.2 to assess whether additional decarbonisation technologies are suitably developed to be included in DR requirements.

6. Design Principles of Decarbonisation Readiness

6.1 Background

In the call for evidence, we identified six guiding principles informing the development of DR requirements. These were based on the primary objective of the DR requirements as being to encourage developers to consider how their projects could be decarbonised at a point in the future, thereby reducing the risk of stranded assets and enabling continued investment in a rapidly evolving power sector. These principles are listed below:

- **The assessments have to strike a careful balance between being meaningful but also achievable.** There are benefits to making the assessments tougher, as this would limit the chances of a developer being overly optimistic about the prospects of decarbonising their plant and, therefore, minimise the risk of stranded assets. However, more stringent assessments would also carry risks, such as limiting innovation or preventing certain technologies from coming forward.
- **The assessments should be based upon a “no barriers” approach.** The current 2009 CCR guidance establishes a “no barriers” approach where developers were asked to demonstrate there were no known technical or economic barriers which might prevent the

installation or operation of their chosen carbon capture technology. The Government did not prescribe which carbon capture technology should be adopted in individual cases, but allowed developers to utilise the best information available at the time and provide a reasoned justification for their choices and conclusions.

- **Developers should be able to change their chosen decarbonisation technology prior to implementation.** The uncertainty around how hydrogen and CCUS policy and technologies will evolve in the future can make it difficult for developers to decide which route will be best for decarbonising their project. Therefore, developers should be permitted to change their decarbonisation technology after having passed the DR requirements, if they can meet the requirements for the alternative technology.
- **Passing the assessments should be mandatory, with the exception of the economic feasibility assessment and, in the short term, the hydrogen fuel access test.** The economics of hydrogen conversion and retrofitting of carbon capture equipment are highly uncertain at the moment, as they will depend on how Government policy and hydrogen and CCUS technologies evolves over the next decade. Therefore, whilst we propose that an assessment of economic feasibility assessment is still required, it would not be necessary to “pass” this assessment. It would, however, be necessary to demonstrate there are no technical barriers to future decarbonisation. Given the limited deployment of UK hydrogen infrastructure to date, our view is requiring developers to demonstrate access to a hydrogen network or supply source (e.g. production or storage site), could be a barrier to entry in the short term. We are minded therefore, to make passing this test non-compulsory in the short-term to reflect this. Our preference is for the first periodic review of DR to be used to assess whether UK hydrogen infrastructure has, or expected to have, expanded to strengthen the test and to make passing it compulsory.
- **The two sets of separate assessments (i.e. the hydrogen conversion readiness assessments and the carbon capture readiness assessments) should be broadly equivalent and mirror one another as far as possible.** We believe this is important to avoid making one decarbonisation route artificially more attractive than the other.
- **Where possible, the robustness of the demonstration of decarbonisation readiness should be proportionate to the capacity of the plant under development.** Once the 300 MW threshold is removed, we anticipate that the number of DR assessments undertaken annually will be relatively much higher than those conducted under the current CCR requirements. Many of these will be for smaller plants, which may be under the ownership of small and medium-sized enterprises (SMEs). It is therefore important that assessments for smaller plants are not disproportionately burdensome.

6.2 Summary of call for evidence responses

Call for Evidence Question 14:

What are your views on our suggested design principles?

30 responses were received for Question 14 with 26 broadly supporting the design principles with three responses disagreeing with aspects of the principles and one response in total opposition to them.

There was general approval in carefully ensuring a balance between meaningful but achievable pathways within the assessment with initial assessment being less stringent due to technology maturity and uncertainty and strengthening the assessments as the technologies mature.

The proposition of assessments being based upon a ‘no barriers’ approach was welcomed for maintaining technology neutrality as much as possible. There was some concern that a restrictive specification could constrain progress, especially given the pace of technological development within the sector. It was also commented that this approach (in line with an ability to change pre-implementation technology) would be good practice to support developers, fostering constructive partnerships between assessors and sites as opposed to a requirement to pass pre-set criteria.

Respondents were favourable to operators being able to change their chosen decarbonisation technology prior to implementation. Some respondents noted that the decisions to do so, should be demonstrably evidenced.

Support was generally given to the tests being mandatory with the exception of the economic feasibility test for both technologies which respondents felt was justified on the basis of current uncertainty in the sector, the immaturity of the technologies, and currently limited GB infrastructure deployment.

The design principle of proposed proportionality of robustness relative to a plant’s capacity received a mixed response.

Additional comments were raised requesting tighter working with Government, stakeholders, expert contractors, developers, local Government, and local planning authorities as the assessment process progresses. Respondents noted that the design principles need to ensure that another uneven approach is not created from step changes in requirements below a certain threshold or create artificially, more attractive pathways. A need to avoid excessively onerous administration for operators was also raised in the context of smaller plant and / or SME’s with additional comments requesting further guidance, clarity and consistency overall. There was reiteration within the comments that CO_2 reduction and the objectives of Net Zero be maintained as the primary factor with the proposed principles.

6.3 Government Response

Government recognises the need for closer engagement with stakeholders, industry, local government, and agencies. We have worked closely with the EA and engaged extensively with industry to develop these proposals. Government will continue to work alongside the EA to implement DR requirements in England through environmental permitting, subject to the outcome of this consultation. We intend to hold open engagement with stakeholders before this consultation closes.

The Government welcomes the positive responses to the design principles and will continue to use them to guide further development of the DR requirements. We have outlined specific proposals for each of the principles below.

6.3.1 The assessments have to strike a careful balance between being meaningful but also achievable

Government continues to recognise the importance of balancing meaningful assessments with achievability. We believe that, given the nascency of both CCUS and hydrogen infrastructure and policy, it would be appropriate for the tests to be less rigorous at the outset but to become more rigorous over time, as certainty around the technology and policy context increases. The proposed regular review of DR requirements to be carried out under regulation 80 of the EPR as proposed in Section 5.2 should facilitate this.

6.3.2 The assessments should be based on a "no barriers" approach

We will maintain this approach for DR requirements going forward to facilitate innovation and flexibility in how developers meet the tests to strike the balance between making the tests meaningful but achievable. We are not introducing any specific proposals for this design principle.

6.3.3 Developers should be able to change their chosen decarbonisation technology

We propose to enable developers to change their chosen decarbonisation technology at any time after receiving their DR permit. The developer would be required to inform the regulator of any changes and provide evidenced justification of their proposed change to ensure ongoing compliance with DR requirements. This approach should allow developers to be flexible in how they decarbonise their plant and to not impose barriers which could prevent a developer from taking advantage of future decarbonisation opportunities. For example, where a developer had received a DR permit by demonstrating carbon capture readiness, but a hydrogen production facility opens close to the plant, the developer can amend their permit to demonstrate hydrogen conversion readiness.

We envisage that the two-yearly review of their plants' compliance with DR by developers, as outlined in Section 5.1, will provide a regular opportunity for developers to assess if an alternative decarbonisation technology may be more appropriate for their individual plant. We propose, however, that developers can change their chosen technology at any time outside of the two-yearly reviews by varying their DR permit.

6.3.4 Passing the assessments should be mandatory, with the exception of the economic feasibility assessment, and in the short term, the hydrogen fuel access test

Government proposes that from the outset of the DR requirements coming into force, developers will be required to demonstrate an assessment of economic feasibility, but that it won't be necessary to "pass" this assessment when demonstrating decarbonisation readiness for either hydrogen conversion or carbon capture readiness.

We recognise that under the current CCR requirements passing the economic feasibility test is mandatory. With the significant expansion of plants within scope and the introduction of HCR we are proposing, it will likely be more challenging for smaller plants to demonstrate economic feasibility given the uncertainty in future running hours and carbon prices, for example. In line with our no barriers approach to DR, Government is concerned that making the economic tests mandatory for both technologies could be a barrier to deployment in the short term. We also note our design principle of proportionality, and we expect larger sized plants to be better able to forecast future economic feasibility as achieved through the current CCR requirements.

As outlined in Section 5.2, Government proposes to use the use the period review of DR requirements to assess whether hydrogen and/or carbon capture technology, policy, and economics have advanced such to make passing the economic assessment for either or both technologies mandatory.

Government recognises the limited deployment of hydrogen infrastructure to date which would make demonstrating the hydrogen fuel access assessment a potential barrier to deployment in the short term. We are therefore proposing to make passing this test non-compulsory in the short-term to reflect this. Our preference is for the first periodic review of DR to be used to assess whether UK hydrogen infrastructure has, or expected to have, expanded to strengthen the test and to make passing it compulsory.

In contrast, we propose that the CCR T&S assessment be mandatory to pass. The CCR T&S assessment is outlined in Section 8.3.5 and the current version of this approach has been suitable and effective since the 2009 CCR requirements were introduced and removing this requirement would reduce the strength of the requirements. Furthermore, there is greater certainty as to where CO_2 geological storage is located relative to the expansion of hydrogen T&S infrastructure. We believe that making it mandatory for CCR but non-mandatory for hydrogen is suitable and proportionate, and we received positive feedback to this proposal in our call for evidence.

6.3.5 The two sets of separate assessments (i.e. the HCR and CCR assessments) should be broadly equivalent and mirror one another as far as possible

Government does not have any specific proposals for this principle. We continue to believe in the importance of this principle, and we have designed our HCR assessments accordingly.

6.3.6 Where possible the robustness of the demonstration of decarbonisation readiness should be proportionate to the capacity of the plant under development

Government is keen not to introduce new market distortions by making it easier or harder to demonstrate decarbonisation readiness depending on the size of plant being considered. We recognise, however, that the proposed removal of the 300 MW threshold will bring smaller plants into scope and which the requirements could have proportionally greater impact on. We will therefore work with the EA to assess what administrative burdens could be made proportional when applying for and demonstrating compliance with DR requirements.

7. Hydrogen Conversion Readiness

7.1 Background

Government views hydrogen as an important and strategic component of our future power system to provide flexible low carbon generation capacity as we integrate more intermittent renewables. We are therefore proposing to enable developers of combustion power plants to comply with DR requirements by demonstrating how their plant could convert to hydrogen generation.

As hydrogen generation generally operates in a very similar manner to natural gas fired generation, i.e., it can ramp up and down quickly, it is potentially more suitable than CCUS to run at a wider range of scales, especially smaller sized combustion plants. With the proposed removal of the 300 MW threshold for DR, we anticipate hydrogen to power to be a potentially more viable decarbonisation route for smaller peaking plants.

Government proposes that developers of eligible combustion power plants will be able to demonstrate that they are “hydrogen ready” through meeting a series of assessments akin to those currently in place for CCR. To avoid favouring one form of decarbonisation route over another we intend, in line with our DR design principles, to ensure equivalency between the assessments for demonstrating HCR and CCR.

In early 2022, Government commissioned a technical study on hydrogen readiness for plants to provide an evidence base on what developers will need to do to demonstrate their plant is technically and economically ready to convert to hydrogen-firing. This information has supported the development of the proposals in this consultation. It will also be used by the EA in the creation of guidance for how developers can demonstrate HCR. This report has been published alongside this consultation.

7.2 Hydrogen Readiness Tests

In our call for evidence, we proposed the following four assessments to demonstrate hydrogen readiness:

- that sufficient space is available on or near the site to accommodate any equipment necessary to facilitate hydrogen conversion;
- that it is technically feasible to convert to 100% hydrogen-firing;
- that the site's location enables access to sufficient supply of hydrogen e.g., transport of hydrogen to the site via pipeline or on-site production and/or storage.
- and that it is likely to be economically feasible, within the power plant's lifetime, to convert to hydrogen combustion.

7.2.1 Summary of responses to the call for evidence

Call for Evidence Question 15:

What are your views regarding the four proposed assessments for demonstrating hydrogen readiness? Are there additional assessments which would be beneficial?

26 respondents provided an answer to question 15. Of the respondents, 15 expressed direct support of the four proposed assessments being reasonable and/ or realistic. There were nine comments supporting elements of the assessments, commenting on possible changes or requiring further clarity. Though most responses stated support on the four tests overall, as opposed for each individual test, some comments on elements of specific tests included:

Test 1 (space requirements):
The main comments around space included (a) Lack of certainty in determining space requirements, including with respect to links to health and safety regulations in terms of space around tanks. There was also mention that space requirements will be dependent on the assumption as to whether hydrogen production is on-site or off-site due to the difference in space requirements between plants accessing hydrogen through a network and those producing and/or storing on site and (b) the need for full consideration of space because, for example, larger diameter pipes may be needed and so other aspects of building design (e.g., access ducts, wall piercings) may need to be designed to be large enough for retrofit.

Test 2 (technical feasibility):
Comments included (a) four responses mentioned the need to consider the uncertainty (including in terms of turbine development by OEMs) that remains around technical feasibility to convert; that demonstrating the technical feasibility of 100% hydrogen firing could pose significant challenges to plants and; that the assessment will be heavily reliant on the OEM guarantee. One response (b) questioned equivalency with CCUS in CCR i.e. why 100% firing is specified if there is no specification for a minimum percentage CO2 capture.

Test 3 (location): Comments included uncertainty in locations of future hydrogen pipelines and infrastructure, and that development of infrastructure is not in the control of the developers. Two responses suggested scrapping of the fuel access test as this would be integrated within the economic feasibility test by default.

Test 4 (Economic feasibility): One response mentioned that because of the uncertainties surrounding it, an assessment of economic feasibility would be meaningless at this point in time.

7.2.2 Proposal

Government welcomes the positive responses on the tests proposed for demonstrating HCR. We are therefore proposing that the four tests set out in the call for evidence be used for plants to demonstrate that they are "hydrogen-ready". Developers will need to be complete all four assessments, but as outlined in the design principles in Section 6, we are proposing that the fuel access and economic tests for HCR are non-mandatory to pass at this point in time to ensure that the requirements are not creating barriers to plants coming forward. We have set out more details on our proposals for each of the assessments in the sections below.

We intend to introduce a new 'Decarbonisation Readiness' schedule into the existing EPR regulations setting out the four tests for developers to comply with in order to demonstrate DR and secure a DR environmental permit.

7.3 Hydrogen space requirements

7.3.1 Background

In our call for evidence, we sought views on our proposals for the hydrogen space requirement assessment.

We also indicated a preference that developers who can decarbonise their plant through conversion to either hydrogen or CCUS should plan for both. For this reason, we suggested in the call for evidence that it may be beneficial that the space requirement for such plants be determined by whichever technology has the largest space requirement (either hydrogen or CCUS), even if the developer has chosen the smaller-sized technology as their preferred option for meeting DR requirements at their plant.

7.3.2 Summary of responses to the call for evidence

Call for Evidence Question 17:

We would welcome views on if there are any additional and/or necessary items for hydrogen combustion that might have space requirements (e.g. NOx abatement equipment) and what their specific requirements might be?

A range of views were provided on additional space requirements which may need to be considered for a hydrogen combustion plant. A number agreed that additional space would be needed for NOx abatement equipment including the potential need for water dilution via steam injection alongside Selective Catalytic Reduction (SCR) technologies. Considerations mentioned also included additional compressors; safety space or separation distance requirements; increased pipeline infrastructure; and internal space requirements such as access ducts and wall piercings for larger sized pipes.

A few respondents expressed views that there is some uncertainty of what “sufficient space” means, as well as that this is likely to vary on whether the plant is planning to access supply through pipeline infrastructure (off-site production) or is producing and/or storing the hydrogen on-site.

Call for Evidence Question 18:

Would it be suitable to require plants that have a choice between hydrogen and CCUS to set aside enough space for whichever technology requires the most space, even if they are planning to meet the DR requirements through hydrogen? How could we ensure that this would only apply to sites which are likely to be able to retrofit CCUS as well as to convert to hydrogen?

A large number of respondents opposed a requirement to leave space for whichever technology requires most space. Views in opposition to the requirement included that the CCUS option would require substantially more space over hydrogen, especially for plants intending to access hydrogen in industrial clusters or through networks as opposed to storing on-site, making the space discrepancy between the two significant. Respondents also noted that requiring CCUS space allocation may hamper deployment of hydrogen combustion plants, impacting network balance and possibly leading to stranded plants. It was suggested that space allocation should be at the discretion of the developer, provided there was a clear robust business case at the outset and a rational acknowledgement of the most viable economic and decarbonisation pathway within the context of plant size, location and realistic access to developed technology. Clarity and further definition on what is meant by “enough space” was also requested.

There were six comments requesting guidance be updated and consistent throughout the process to clarify positioning as technology and infrastructure develops. Views on specific cases where it would not be reasonable to demonstrate sufficient space for both technologies included (a) size (one response mentioned that such a requirement may be suitable for larger sites and suggested requirements should be subject to a 50 MW threshold), (b) access to supply (it was suggested that if plants can meet the criteria and that it has a good prospect of connecting to a hydrogen network/clear opportunity to use hydrogen fuel, there should be no requirement to allocate space for CCUS), and (c) geographical location (one response suggested that there are sites that will not be suitable for CCUS due to their geographical location or space constraints).

7.3.3 Proposal

Government is proposing that as part of the space demonstration test for hydrogen, plant operators will be required to set aside adequate space for additional equipment needed for hydrogen combustion as well as safety space requirements, both internally and externally, to accommodate their chosen hydrogen technology. Additional equipment could include, for example, NOx emission abatement equipment, hydrogen supply infrastructure, combustor/burner modification or flue gas recirculation. The space set aside should also align with the plant's plans for accessing hydrogen. For example, if a developer is planning to store and/or produce hydrogen on site, the plans should demonstrate space has been set aside to meet this need.

We intend to set our guidance on space requirements as part of the guidance developed by the EA. Our recent technical study has assessed land footprint requirements for hydrogen conversion and this information will underpin the guidance. We expect this information will be reviewed as part of the proposed DR reviews to ensure it keeps pace with technological development and remains helpful for developers and assessors.

In line with feedback from the call for evidence, Government is proposing that plants **will not be required** to set aside space for the decarbonisation technology which requires more space. We recognise that due to the land footprint required for CCUS, a necessity to set aside space for CCUS could limit the deployment of hydrogen.

We are also not minded to introduce a threshold above which developers would be required to demonstrate space for both technologies as this could carry the risk of creating a new market distortion akin to one created by the current 300 MW threshold.

Whilst there is no requirement for developers to set aside space for both technologies, some who have the space at their plant may wish to consider setting aside space for both in the interest of providing themselves with more flexibility, and to set aside a contingency plan should decarbonising through hydrogen technology not be possible for them in the future.

Consultation Question 16:

Do you agree with our proposed outline for a hydrogen readiness space requirement test?

7.4 Hydrogen technical feasibility

7.4.1 Background

In our DR call for evidence, we sought views on a test for plants to demonstrate HCR through technical feasibility of conversion to 100% hydrogen-firing. We think it is important that eligible new build and substantially refurbishing combustion power plants are configured in such a way that future technical works to convert to 100% hydrogen firing are as straightforward as possible and that there are no known technical barriers.

7.4.2 Summary of responses to the call for evidence

Call for Evidence Question 19:

We would appreciate your views on these issues, including whether there are any we have overlooked, and how we can best assure/assess that developers have considered all the relevant technical issues.

A number of responses agreed that the example technical considerations we set out in the call for evidence document were comprehensive. There was also a suggestion that OEMs were better placed to respond or bear the responsibility of technical feasibility at the point of development. It was noted that the proposed technical list should be subject to monitoring during progression to better understand impact and feasibility. There were no remarks disagreeing with any of the proposed technical issues.

Safety implications, considering hydrogen is more flammable, colourless and odourless, were raised by stakeholders. Similarly, there were comments regarding how environmental permitting would interact with the safety concerns and associated hazards, especially as risks will be highly spatially concentrated in particular areas. This included electrical and leak detection of hydrogen in areas where its potential presence would be hazardous. One response also questioned whether Government was assuming by-products from the combustion process (condensates etc.) are safe for disposal or whether further processes be required. In addition, NOx abatement/emissions were also raised as being a key barrier within hydrogen firing, with limited ‘off the shelf’ solutions.

Two responses mentioned the requirement for new technical training being available and required for staff at conversion sites. Other technical issues for consideration raised included that fire and gas detectors will need replacing, as those designed for natural gas will not detect hydrogen leaks or hydrogen flames, and that hydrogen-fuelled gas turbines most likely will require a green carbon neutral liquid fuel for start-up. The proposed intention to commission a study on hydrogen readiness to improve understanding of potential technical barriers was welcomed within the responses. One response mentioned decarbonisation ready approaches for Combined Cycle Gas Turbines (CCGT) plants, CHP plants, peaking plants, and biomass power involve different technical and economic factors and therefore should be considered separately.

7.4.3 Proposal

Government welcomes the feedback from respondents. Our proposal is to retain the “no known barriers approach” from the current CCR requirements whereby new build or substantially refurbishing combustion power plants are configured in such a way that future technical works to convert or retrofit to hydrogen are as easy as possible. The works required may vary depending on the combustion technology, e.g. engine or turbine and the manufacturer of the equipment.

We intend that the EA will set out a technical checklist as part of the DR permitting guidance they issue. This checklist will provide information on what is necessary to satisfy this requirement. The technical study we commissioned on hydrogen readiness has built the evidence base to underpin this technical checklist.

Consultation Question 17:

Do you agree with our proposed outline for a hydrogen technical feasibility assessment?

7.5 Hydrogen fuel access

7.5.1 Background

Ensuring a plant is located so that it is likely to have a sufficient and reliable access to a source of hydrogen supply in the future, either directly from on-site production or via a supply network/storage, will be fundamental to ensuring hydrogen conversion is viable.

We proposed a hydrogen fuel access assessment in our call for evidence, with the purpose of ensuring developers critically assess the viability of the options available for securing an adequate supply of hydrogen fuel to their site in future. Potential approaches to this assessment could include developers considering whether their plant is located sufficiently close to an actual or anticipated hydrogen supply cluster or production site, or it is possible to connect to a hydrogen supply network.

Bearing in mind the developing nature of hydrogen infrastructure, we also sought views on making "passing" the hydrogen fuel access assessment non-compulsory to obtain a permit in the short-term. This approach would still require developers to consider hydrogen fuel access in the short to medium-term, but it would not act as a barrier to entry due to the uncertainties of hydrogen infrastructure locations.

7.5.2 Summary of responses to the call for evidence

Call for Evidence Question 20:

We welcome your views on how to design a meaningful assessment for hydrogen fuel access.

Question 20 produced responses with a range of views on the design of a hydrogen fuel access assessment. Considerations raised included (a) sufficient availability of hydrogen supply (b) risk and security of supply, (c) Memorandums of Understanding (MoUs) and partnerships with hydrogen suppliers, and (d) proximity to the existing gas grid, given ongoing work to demonstrate the technical and economic advantages of re-purposing the gas grid to distribute hydrogen. Ten responses mentioned consideration of proximity to clusters, regional industrial decarbonisation activities, planned production and transportation facilities or hubs. Partnerships and MoU arrangements with hydrogen suppliers was also raised. Four comments were made concerning the links between the fuel access test and the proposed economic test.

There were also mixed views on whether the test should be mandatory. A number of responses agreed that the lack of clarity on the development of hydrogen networks and markets means that any short-term assessment of probability/feasibility will be almost meaningless and that this test should not be mandatory in the short-term at least. A few responses stated they believed one element of the hydrogen fuel access test should be mandatory in the short term, and that though they recognise that the assessments set out presented a robust view. In the short term at the very least, they felt, developers should be able to point to a source of hydrogen and continue to develop the access arrangements over time, and that any projects in development should have an early indication as to how it would access hydrogen. Supporting this view, several responses mentioned that in the short term, plans through the cluster sequencing process and agreements/MoUs in place with prospective hydrogen producers could be considered as evidential. There were several comments stating requirement to review the assessments with the network providers regularly to cover network expansion, general infrastructure, policy integration and costs.

Call for Evidence Question 21:

We welcome your views on our likely position to make the hydrogen fuel access assessment non-compulsory in the short-term, with a view to making "passing" it mandatory in future to reflect the anticipated development hydrogen economy.

There were 24 responses to question 21 with 16 expressing full or partial support for the principle of short-term non-compulsory fuel access assessments, with a further five against in full or part. The five against cited potential lock-in of emissions, developments in non-suitable locations and a need to ascertain viable indications going forward. There were additional comments regarding the national progression of CCUS and hydrogen projects and developments, and compulsory fuel access assessments providing an opportunity to feed into that growth. It was also raised that future mandates should not be retroactive in implementation through three responses which questioned what would happen to existing plants (who initially passed the test when it was non-compulsory) but fail when it becomes compulsory – whether they would become stranded assets, or whether the test would only apply to newly commissioned sites after the change. There was a comment referencing the fact that a hydrogen ready plant may still depend on natural gas or non-electrolytic hydrogen. It was further noted and reiterated that location of hydrogen supply is more likely to be viable nearer to industrial clusters with plants outside this sphere facing additional challenges with some request for continued clarity in the ongoing process.

Call for Evidence Question 22:

We appreciate your views on the viability of on-site hydrogen supply and/or storage for hydrogen-fuelled peaking plants

Question 22 received 23 responses with varying positions and views on viability. From the 23 responses seven stated that they do not think it is viable, one directly stated that they think it is viable, three thought it would be viable in the long-term, and seven stated they think it's too early to tell, we need more information, or it is viable subject to some considerations.

The seven responses that thought it was too early to tell, needed more information, or thought it is viable subject to further considerations, included the following reasons: (a) Scale of production - that viability could depend on scale of production needed, and large volumes of hydrogen production could make small-scale plants uneconomic to run as they would entail high consumption for relatively short periods. One response mentioned the need to better understand potential hydrogen usage rates for particular plants to better assess production and storage volume requirements. Five responses mentioned space for production/storage, the uncertainty of how much space is required, including space to meet wider regulatory and hazardous substance requirements. There was mention of size of storage tanks potentially being an issue. Safety consideration (c): mentioned by five responses, including that viability would be subject to Health and Safety Executive (HSE) and Control of Major Accident Hazards (COMAH) position, and that safety could be a potential challenge/barrier. One response mentioned that sites requiring on-site production/storage will be pushed away from urban areas (due to safety but also less-expensive land prices) which could result in a lack of flexibility in more densely populated urban areas, where this is typically most beneficial.

One response raised the idea of co-location of hydrogen supply and storage with hydrogen-fuelled gas turbines, and the benefits this would provide supporting blue hydrogen production if there were multiple co-located flexible off-takers to allow efficient baseload operation of Steam Methane Reformers (SMRs)/Autothermal Reformers (ATRs) and address potential volume risk issues.

Five responses mentioned the cost of on-site production and storage being prohibitive, or making it economically unviable, for reasons including capital cost of the store, additional land required, and that it therefore might not be credible for sites, other than those of small capacity. However, three responses of these mentioned that it would become more economically viable over time as industry and hydrogen technology matures.

7.5.3 Proposal

We recognise the infancy of low carbon hydrogen production and current uncertainties in hydrogen infrastructure locations. We anticipate that low carbon hydrogen supply will expand over the coming decade as hydrogen has the potential to provide low-carbon alternatives not only to power, but also to industry, transport, and heating. Government is actively supporting the expansion of hydrogen infrastructure, and in the British Energy Security Strategy (BESS) we doubled the UK's ambition for low carbon hydrogen production capacity to up to 10GW by 2030.[59] BESS also committed HMG to design new business models for hydrogen T&S infrastructure by 2025. A consultation on the high-level design options for the hydrogen transport and storage business models ran from 31 August 2022 to 22 November 2022. A Government Response is planned to follow in Q2 2023.[60]

It may be possible in the long term that the existing gas network, or new network infrastructure, could carry hydrogen in sufficient quantities to adequately supply hydrogen-fuelled power plants over long distances. Supply could potentially also come by methods other than pipeline e.g., rail or road, provided there are hydrogen storage facilities at the site. We anticipate that non-pipeline distribution may be possible for smaller sized "peaking" plants, which may have sufficient on-site hydrogen storage capacity to meet the plant's demand for limited running hours.

However, we recognise that in the short-term, it will likely be challenging for developers to anticipate future connection to a suitable hydrogen fuel supply and so meaningfully demonstrate compliance with a hydrogen fuel access assessment due to the limited UK hydrogen supply and production infrastructure. Therefore, we propose that for the hydrogen fuel access assessment it will be non-compulsory to "pass" in the short-term. Although the passing is non mandatory in the short-term, developers will still be required to set out their planned route and plan for hydrogen access. As the hydrogen economy develops and more infrastructure becomes available, it will be easier for developers to meaningfully demonstrate connection and so "pass" the test.

We plan to undertake a review of our position on this assessment as part of the proposed periodic review of DR set out in Section 5.2, to assess if hydrogen infrastructure has expanded or is on course to have developed sufficiently to make passing the hydrogen fuel access assessment mandatory. For example, as the hydrogen economy becomes established and hydrogen infrastructure expands, the hydrogen fuel access assessment could be strengthened with a requirement to be located within a specified distance from a hydrogen supply point (e.g., cluster or production site). This would minimise the risk the plant becomes stranded because it was unable to access a suitable hydrogen supply.

Any update to make the fuel access test compulsory will be kept under review. If, and when a fuel access assessment is made compulsory, a barrier to fuel access is identified as part of an existing individual DR plants assessment, this would not necessarily be treated as non-compliance with the permit, however, developers should consider any barrier identified carefully explore solutions accordingly.

We propose to also allow developers to comply with the hydrogen fuel access assessment by demonstrating suitable on-site production and/or storage, including analysis of considerations such as sufficient space requirements have been undertaken. As outlined in the call for evidence, we understand that there are uncertainties in the viability of on-site storage,

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59 https://www.gov.uk/government/publications/british-energy-security-strategy/british-energy-security-strategy

60 https://www.gov.uk/government/consultations/proposals-for-hydrogen-transport-and-storage-business-models

however, these uncertainties are reflected in our proposals to make “passing” the fuel-access test non-compulsory in the short term. We also expect to include updates on viability of on-site supply and storage as part of DR’s periodic review as clarity on technicalities is developed in order to increase robustness of the assessment.

One of our design principles outlined in Section 6 is to ensure the assessments for HCR and CCR are broadly equivalent and mirror one another as far as possible. In relation to T&S / fuel access assessments, however, Government considers that the assessments should reflect their corresponding technologies and so be disparate. Our intention, therefore, is to retain the CCR CO_2 T&S assessment as mandatory to reflect the differences in how developers can demonstrate connection to the two technologies infrastructure. The limited UK hydrogen infrastructure makes it more challenging for developers to identify a suitable fuel source connection. The CCR CO_2 T&S assessment requires developers to identify a potential deep geological offshore storage area or identify a suitable CO_2 T&S network to connect with. These are more well known to industry, and so developers opting for CCR would remain able to demonstrate their plant’s.

Consultation Question 18:

Do you agree with our proposed outline for a hydrogen fuel access assessment, and our proposal to make it non-mandatory to pass in the short-term?

7.6 Hydrogen economic feasibility

7.6.1 Background

In our call for evidence, we sought views on the inclusion of an economic feasibility test for HCR, as the economics of conversion and operation of their plant with 100% hydrogen firing technology will be a major factor in whether developers are able to decarbonise their combustion power plants. In principle, the assessment of the economic feasibility should involve comparing the increased capital and operating costs of hydrogen conversion with the potential for increased revenues following conversion due to avoided carbon costs. A range of factors will determine the economic feasibility of conversion to hydrogen-firing, and we sought views on these factors.

7.6.2 Summary of responses to the call for evidence

Call for Evidence Question 23:

What factors are viewed as critical in determining whether conversion to hydrogen is economically feasible? What would be your economic considerations?

Question 23 received 25 responses with six clearly agreeing with the listed factors set out in the Call for Evidence and as such, supporting the proposed economic feasibility assessment being required but not necessary to ‘pass’. There was one comment pushing for this assessment to be mandatory. Overall, the general responses proposed several factors critical to the economic feasibility of the conversion to hydrogen, which in order of most referenced, were the cost of hydrogen fuel (both unit and in part production), investment feasibility relative to rate of return, site infrastructure requirements, access to hydrogen and fuel logistics, market-imposed restrictions, security and risk mitigation, current technology maturity and CO_2 abatement. Other considerations raised by responders included reliability of hydrogen supply, any additional fixed operation and maintenance costs, restrictions on running hours for gas-fired plants, and role in the power market and position in the merit order. Availability of finance, Government incentivised investment and subsidies were also identified by stakeholders.

7.6.3 Proposal

A range of factors will impact the economic feasibility of conversion to hydrogen. Due to uncertainties in determining factors such as costs of conversion, in particular the cost of hydrogen fuel relative to natural gas, future policy mechanisms, and hydrogen T&S developments, we are proposing that it will initially be non-mandatory to pass this test. Therefore, whilst we propose that assessment of economic feasibility will need to be made by developers, it will not be necessary to "pass" the assessment. This is also in-line with the proposal for CCR.

The Government's Hydrogen Business Model will provide revenue support to producers to overcome the operating cost gap between low carbon hydrogen and high carbon counterfactual fuels.[61]In terms of power end use, we are currently undertaking work to explore the need and case for further market intervention to support hydrogen to power.

We expect to review our position on this assessment as part of the proposed regular reviews of DR set out in Section 5.2.

Consultation Question 19:

Do you agree with our proposed outline for a hydrogen economic feasibility assessment, and our proposal to make it non-mandatory to pass in the short-term?

7.7 Hydrogen firing capability

7.7.1 Background

In addition to the four assessments for demonstrating hydrogen readiness, in the call for evidence, we put forward an additional requirement for all plants which choose to demonstrate DR through hydrogen conversion. We sought views on whether eligible plants which come online during or after 2030 should be required to install generation equipment (e.g,. a turbine) technically capable of firing 100% hydrogen from the point of initial operation. They would still be permitted to use 100% natural gas as a fuel, but the installed equipment would simply need to be *capable* of handling either 100% of either fuel or a blend of hydrogen and natural gas, were this to be available.

The purpose of this would be to send a strong market signal to Original Equipment Manufacturers (OEMs) to develop generation equipment capable of firing 100% hydrogen, and to ensure that operators are on the front foot with their conversion to hydrogen-firing. This may also be more cost effective to developers in the longer term as they would not need to purchase new generation equipment when they come to decarbonise. This proposal may also encourage the uptake of hydrogen blending, where available, as an interim decarbonisation step and to provide demand sources for hydrogen.

[61] https://www.gov.uk/government/consultations/design-of-a-business-model-for-low-carbon-hydrogen

When setting the dates for this requirement, we recognise the need to be cognisant of two factors. Firstly, that the dates are in line with when hydrogen combustion units (turbines/engines) are likely to be available from manufacturers. Secondly, that the dates are in line with the expected increase in the availability of hydrogen fuel itself. Based on our industry engagement, our view is that the majority of gas turbine engines and engines currently available on the market could be capable of firing a blend of 20%-30% hydrogen with modest modifications.

In terms of 100% hydrogen firing generation equipment, our engagement with OEMs indicates that 100% capable hydrogen firing generation equipment will be available on the open market by 2030. Additionally, the technical study we commissioned to support the development of HCR requirements also concluded that 2030 was a suitable date for 100% capable hydrogen firing generation equipment to be available.

In our call for evidence, we proposed that the dates of demonstrating technical capability could vary depending on the date of construction, for example:

(1) burning at least a 20% blend of hydrogen from the point they are put into operation from the point DR requirements are implemented, and;

(2) technically capable of burning 100% hydrogen if built after 2030.

We anticipated these requirements could be met through a declaration from the generation equipment manufacturer certifying the percentage of hydrogen the generation unit is capable of firing.

7.7.2 Summary of responses to the call for evidence

Call for Evidence Question 16:

What are your views on the suggested requirements for hydrogen ready plants to demonstrate hydrogen blend capability from the point of construction, including the example of 2030 as a cut-off for 100% hydrogen?

There were 27 responses to question 16. 19 expressed support and/or agreed with the proposed requirement to demonstrate a blend capability pre-2030, with 14 supporting the proposal for demonstrating 100% firing capability post-2030. Within the overall responses there were 13 requesting a review of the 2030 date with five suggesting that date could or should change. Three responses mentioned that dates earlier than 2030 should be considered, including one suggestion that subject to the success of current testing, equipment could be ready by 2026, and other suggestion of 2028.

There was also concern raised that 100% firing capacity for retrofit plants would effectively mean new plant refit due to the extent of modifications, which could prevent or hinder refurbishment of existing infrastructure. It was also noted that proposed cut-off dates could cause a pre-2030 rush to avoid requirements. There were seven comments suggesting that the proposed requirements also fall into the DR guidance review. These comments regarding review of guidance and dates aligned with ten comments conveying concern regarding the nascency of hydrogen technologies and uncertainties concerning logistics, production volumes and storage.

There were several comments in agreement that DESNZ's proposed date of 2030 would contribute towards sending a strong signal to the sector OEMs. Five respondents explicitly agreed with the assumption made in the call for evidence that currently available equipment can burn 20-30% hydrogen with small adjustments.

7.7.3 Proposal

We welcome the responses received in our call for evidence. We propose that eligible combustion power plants which opt to demonstrate DR through hydrogen conversion, and which are put into operation after 1 Jan 2030 must have installed generation equipment capable of firing 100% hydrogen.

Plants would still be permitted to use 100% natural gas as a fuel, though the equipment would need to be capable of burning 100% hydrogen. If put into operation before 1 Jan 2030, plants will need to demonstrate they are hydrogen *ready*, meaning there are no technical barriers to converting, as per the technical feasibility test in the four proposed assessments. In line with the feedback from the call for evidence, Government intends to keep the 2030 date under review as knowledge on the commercial availability of hydrogen firing equipment develops from manufacturers and OEMs. We will review this date as part of the period review of DR proposed in Section 5.2.

Government is **not** proposing to require plants to demonstrate hydrogen blend (e.g., 20% by volume) capability from the point of construction. The BESS reinforced the strong need to go further and faster in achieving our CB6 and net zero targets and this will require maximising decarbonisation opportunities wherever possible. Our view is whilst firing a blend of hydrogen and natural gas creates some CO_2 emissions reductions, there is a risk that developers are not incentivised to maximise decarbonisation opportunities and convert to 100% hydrogen firing, and so greater emissions reductions.

Whilst developers operating with a blend of hydrogen and natural gas is permissible within the DR requirements, a plant would not meet the proposed definition of decarbonised within the context of DR (i.e., installed and operating 100% hydrogen firing generation technology).

The Government has not yet decided whether to enable blending of up to 20% hydrogen (by volume) into GB gas distribution networks. We are targeting a policy decision in 2023, subject to the outcomes from ongoing economic and safety assessments and wider strategic considerations. UK Government officials are working closely with Ofgem, HSE, the Devolved Administrations, the gas networks and wider industry to understand the case for hydrogen blending and build the necessary evidence-base to determine whether blending meets the required safety standards, is feasible, and represents value for money.

Consultation Question 20:

Do you agree with Government's proposal to require all eligible new build or substantially refurbishing combustion power plants which opt to meet DR requirements through hydrogen conversion to also have to demonstrate capability of burning 100% hydrogen if they are put into operation after 1 Jan 2030?

Consultation Question 21:

Do you agree with Government's position of not requiring demonstration of plants' capability of burning a blend of hydrogen?

8. Carbon Capture Readiness

8.1 Background

In updating the DR requirements, we also wish to review the current "Carbon Capture Ready" (CCR) requirements with a view to ensuring they remain fit for purpose and reflect the current policy, technical, and economic landscape of carbon capture usage and storage (CCUS).

The strategic case for power CCUS and the deployment pathway is presented in Section 2.2.2. The Net Zero Strategy (NZS) and the British Energy Security Strategy (BESS) set out the critical role of carbon capture, usage and storage (CCUS) in delivering net zero by 2050, and the Government's commitment for a fully decarbonised electricity system by 2035. Power generation with CCUS, power CCUS, will be vital to both objectives.

The existing CCR requirements ensure that power plants above 300 MW are CCR. Prior to receiving development consent, a number of assessments need to be carried out relating to the technical and economic feasibility of capturing, transporting and storing its emissions of CO_2. We are now proposing that CCR is one of two decarbonisation routes within DR, and therefore this section of this consultation will cover aspects related specifically to the CCR route only.

In our call for evidence, we requested views and evidence for updating CCR. We said that we were minded to retain the technical feasibility test, remove the pass/fail from the economic feasibility test, and retain the space requirements. We noted that the information underpinning the space requirement test quickly becomes outdated and proposed to remove this from the guidance. We also proposed a new option in the transport and storage (T&S) test, where plants can identify a transport and storage (T&S) network to connect with. This would be one of two options to demonstrate the T&S test. The alternative, retained from 2009 CCR, is to demonstrate a direct route to a suitable area of deep geological storage offshore.

In early 2022, we completed a study on CCR to update our knowledge base on what this means both technically and economically, particularly for plants sized below 300 MW. It will also be used by the Environment Agency (EA) in the creation of guidance for how developers can demonstrate CCR. This report has been published alongside this consultation. More generally, we continue to work closely with the EA to ensure the updated requirements will be fit for purpose.

We are working closely with Defra and the relevant regulators to ensure that CCUS technology can be deployed in a safe and transparent way, which is compliant with regulations and allows us to meet the goals of the CCUS Programme.

8.2 Summary of call for evidence responses

Call for Evidence Question 24:

What are your views on our proposed updates to the CCR requirements?

Question 24 received 25 responses, including those which generally addressed question 24, 25 and 26 simultaneously. 18 (72%) responses broadly agreed with the proposed updates to the CCR requirements, with the remaining seven (28%) expressing no general agreement or disagreement. However, one of these seven responses did express disagreement with multiple aspects of the proposed changes.

Several responses noted that the proposals may be challenging for, or prevent development of, some projects depending on their size and location. Reasons included proximity to a cluster, excessive burden on small projects, lack of non-pipeline transport for remote emitters, and lack of space in urban/industrial areas. One response noted that the proposals may stop development in some areas where generation is need for system security. Multiple responses requested suitable support for projects following the CCR pathway, through sufficient guidance, recommendations, or financial incentives to ensure applications are completed to a high standard, especially for small to medium sized projects. Similarly, several responses supported studies to update the knowledge base, and requested that respective governments and regulators be consistent in the application of the requirements.

Seven responses explicitly agreed with the removal of the pass/fail on the economic feasibility test. One response disagreed and one response expressed concern it could become meaningless and hence requested clear expectations on what constitutes sufficient detail and quality, and powers for the regulator to request improvements when these are not met.

Three responses explicitly agreed with the retention of the space requirement and one response disagreed on the basis that it did not guarantee CCUS could be retrofitted. This response disagreed with many of the proposed changes, arguing instead for a more extensive CCUS retrofit study. Multiple responses also supported the removal of some of the prescriptive detail, including in relation to the space requirement, that can become rapidly out of date.

Call for Evidence Question 25:

What are your views on how the transport and storage test for CCR should be updated?

Question 25 received 24 responses. Six (25%) responses expressed agreement with the proposals on how the transport and storage test for CCR should be updated, with all other responses not stating a general opinion. However as noted for Question 24, the majority of respondents expressed general support for the proposed updates to the CCR requirements, which include these updates.

Eight responses recommended that non-pipeline transport should be considered as a viable alternative to pipeline transport. The types of non-pipeline transport were not always defined, but responses that were specific included shipping, road and rail. Justification included retaining flexibility, consistency with the proposed changes to the CfD regulations, and reducing barriers. Multiple responses said that non-pipeline transport updates should allow for a modular approach, where the transport and storage elements can be operated by multiple parties separately, rather than only one integrated solution. However, one response supportive of non-pipeline transport did note the complexities of non-pipeline transport solutions and need for any assessment to ensure any solution results in permanent storage.

Multiple responses requested clarity on engagement with a prospective transport and storage (T&S) network, particularly the responsibilities of the T&SCo to support projects when applicants elect to evidence plans to connect to a suitable T&S network under the transport and storage test. Responses questioned the obligations on the T&SCo to connect emitters, including being guaranteed access in a timely manner. Respondents also said engagement from both parties would support the management of prospective storage, allocation of capacities, and future expansion decisions.

Multiple responses requested sufficient information on how the feasibility of a T&S test will be assessed and who will assess it. Two responses also questioned whether applicants that are in the vicinity of a T&S network but choose to propose new, alternative T&S infrastructure should be subject to further tests/justification.

Single responses suggested: testing of proposed storage options and sharing of this information; the inclusion of onshore saline aquifers; clarity on the boundaries of responsibility for a T&SCo; contingency plans for cluster unavailability; the need to update existing storage resources; recognition that infrastructure may be less mature in some areas; and that changing transport corridor to a more economically or technically efficient alternative storage should not be compulsory.

Call for Evidence Question 26:

Are there additional areas for change we have not identified? Please provide justifications.

Question 26 received 17 responses identifying additional areas for change. Ten of these responses recommended the inclusion of carbon capture and usage as a reasonable alternative to, or broader definition of, permanent storage. Some respondents defined usage as resulting in permanent storage, some in usage that results in emissions, but most were not specific. Multiple responses said that usage could be a more suitable alternative for projects which are geographically distant from a suitable store or cluster. Other justifications included encouraging innovation, providing a catalyst for future connections to a T&S network, and it being an option of last resort. Multiple responses suggested that usage may be most appropriate for projects using biogenic fuels.

Four respondents mentioned Capture as a Service (CaaS) and the lack of provision for CaaS projects in the current proposals. Respondents said that CaaS projects could be the best option for some small to medium sized emitters and that CaaS proposals would achieve the broad aims of DR.

Two responses requested that carbon offsetting be included as an alternative to demonstrate net zero emissions. Single responses suggested: consideration for on-site CO_2 storage; consideration for all types of carbon capture technology; whether the requirements would apply to plants with CCUS already fitted; and whether there would be minimum capture rates and whether these may vary depending on fuel type e.g. biomass.

8.3 Proposals

In updating the DR requirements, we have reviewed the CCR requirements with a view to ensuring they remain fit for purpose and reflect the current policy, technical, and economic landscape of CCUS. Here we set out our proposals for retaining, removing, or amending aspects of the requirements. The proposals build upon the DR call for evidence and consideration of the views and evidence provided by responses to Question 24, 25 and 26.

In 2022, we completed a technical study on CCR to update our knowledge base on what this means both technically and economically, particularly for plants sized below 300 MW. This information has supported the development of the proposals in this consultation. It will also underpin the information provided in the guidance to developers and used as a benchmark for assessment of submissions.

The CCR proposals have been designed to strike a balance between ensuring plants do not become stranded as they are unable to access the infrastructure necessary to decarbonise and limiting the burden the test places on developers and potentially creating a barrier to entry. Our intent is to ensure parity in test requirements between HCR and CCR to avoid distortions in making one decarbonisation route easier to demonstrate than the other.

We intend to introduce a new 'Decarbonisation Readiness' schedule into the EPR regulations detailing the four tests for developers to comply with, in order to demonstrate DR and secure a DR environmental permit. The four tests for CCR will be:

- that sufficient space is available on the site to accommodate any equipment necessary to facilitate CCUS;
- that it is technically feasible to retrofit a CCUS plant to the combustion power plant;
- that the site's location enables access to offshore permanent storage for the CO2;
- and that it is likely to be economically feasible, within the power plant's lifetime, to retrofit CCUS. This test would be non-mandatory to pass.

8.3.1 CCUS plants

Projects that include carbon capture technology from the outset, in any configuration defined as 'decarbonised' in Section 2.3, are already compliant with Decarbonisation Readiness.

8.3.2 Technical feasibility test

We have reviewed the technical feasibility test and believe it generally remains fit for purpose. In order to pass the technical feasibility test, capture plant proposals where 'best available techniques' (BAT) applies would be required to be capable of achieving BAT to pass. For example, for post-combustion carbon capture (PCC) utilising amine-based technology, this requires plants to demonstrate a design CO2 capture rate of at least 95%.[62] Where developers are proposing alternative technology, developers would follow the relevant BAT reference document (BREF) note and the technical guidance for activities that don't have BAT conclusions.[63] As noted in Section 2.3, we would however not consider any solutions below 90% capture rate of CO2 generated by the facility to be DR. This is in line with the eligibility for a DPA.

Expanded guidance will be provided by the EA on what information is required to satisfy this requirement for different plants and sizes. In providing this guidance, we intend to support small projects through the technical feasibility test. Our technical study has informed the revision of a technical checklist that the regulator will use to develop guidance to aid assessment of submissions.

All developers would need to demonstrate technical feasibility. We do not intend to allow for developers to use CO_2 offsetting to demonstrate CCR in any case, including where is not feasible to demonstrate technical feasibility or any aspect of the CCR pathway. We have

[62] https://www.gov.uk/guidance/post-combustion-carbon-dioxide-capture-best-available-techniques-bat
[63] https://www.gov.uk/guidance/best-available-techniques-environmental-permits#how-to-propose-an-alternative-technique

considered this position and believe that any proposal that includes offsetting would not represent a meaningful assessment. This purpose of DR is also to drive decarbonisation of power plants and encourage the expansion of CCUS and hydrogen economies.

8.3.3 Economic feasibility test

We propose that it will no longer be necessary to “pass” the CCR economic feasibility test. This is in line with the approach proposed in relation to HCR, and due to the inherent uncertainties associated with the economics of CCUS, especially for smaller plants. Developers will still be required to complete an economics assessment to a sufficient standard and review this periodically in line with the periodic review of a plants’ DR compliance (see Section 5.1). Guidance will be provided by the EA to outline what information is required from developers to meet that standard. The EA will therefore continue to review the economic feasibility test as part of their overall review of DR submissions.

8.3.4 Space requirement

We believe the space requirement generally remains fit for purpose. Maintaining the space requirement will ensure projects will retain sufficient space onsite for the capture plant, compression, and any other equipment proposed by the developer in the technical feasibility test.

Our recent CCR technical study has provided information that will support the assessment of submissions. This study considered the space requirements for the retrofit of carbon capture to an existing plant and presented indicative data for plants using an amine-based capture technology. This indicative information will be reviewed as part the proposed regular review of DR requirements proposed in Section 5.2 to ensure it keeps pace with technological development and remains helpful for both developers and assessors.

As capture technologies are rapidly developing, we do not believe it is appropriate to impose definitive requirements on the amount of space to be set aside for a given plant capacity. Applicants will continue to provide reasoned justification in their submission based on their individual circumstances and chosen capture technology. This approach will increase the flexibility of proposals, while retaining information on indicative space requirements should support smaller emitters when preparing information for submission. As the deployment of capture technology accelerates, the indicative information will become more meaningful. Therefore, Government would expect that in time, submissions would include stronger evidence to support their submitted space requirement if it differs significantly from the indicative information, especially in the case of larger projects.

We have considered the provision for Capture as a Service (CaaS) within DR following its inclusion within Phase-2 of the CCUS cluster sequencing process for Industrial Carbon Capture projects. A CaaS solution is the provision of one capture plant, operated by a CaaS Group, third party or potentially a lead emitter, for abatement of CO_2 from multiple emitters in one area. We consider that CaaS broadly aligns with the decarbonisation objectives of DR, and may be a desirable option in certain circumstances for small emitters. However, the provision of CaaS presents significant challenges to the application of the space requirement, as well as other parts of DR policy and its function in Environmental Permitting Regulations (EPR). A CaaS proposal may retain land as a group or have an agreement to joint use of a sufficient land, but we believe we cannot specifically provision for this within the regulations such that it would represent a meaningful assessment and not act as a loophole to the space requirement. We therefore propose not to specifically define CaaS as an option at this stage, and instead look to review this position in the future. We would welcome feedback on this position if there is an alternative solution, especially in relation to the EPR.

8.3.5 Transport and storage (T&S) test

We propose that it remains mandatory to pass the transport and storage (T&S) test and we propose there would be two options in order to do so. This follows our review of the current assessments and the feedback from our call for evidence.

We propose to retain the option whereby developers identify a viable transport route from their plant to a suitable area of deep geological storage offshore. The second new option will be to identify a suitable CO_2 T&S network to connect with. We expect that as CO_2 transport and storage networks around the UK develop, identification of how a combustion power plant might connect to a T&S network may become a more appropriate approach for many plants in the future. The current CCR guidance "Transport Networks" section already signals this thinking.[64] Developers could update their chosen transport corridor and/or destination if a more economically or technically efficient alternative transport and storage solution becomes available.

To pass the T&S test developers will need to either:

(a) identify a suitable area of deep geological storage offshore exists for the storage of captured CO_2 from the proposed power plant and demonstrate that a feasible route exists from the site to the storage area, or

(b) identify a suitable CO_2 transport and storage (T&S) network to connect with, to facilitate the onward transport and storage of CO_2 from the proposed power plant, and demonstrate that a feasible route exists from the site to the T&S network.

To understand the technical feasibility of either T&S option, we expect developers to consider the technical operability of the chosen T&S solution, factoring in expected running patterns of the power plant.

In order to demonstrate identification of a suitable CO_2 transport and storage network to connect with, we expect developers to provide evidence of how they have communicated with, or endeavoured to communicate with, the respective T&SCo. In this communication, we expect developers and the T&SCo to investigate their connection, and the future potential for provision of storage capacity. A T&S network identified in option b) should be considered 'suitable' once the T&S network meets the requirements of option a), from the point of connection to store. This would make T&S networks at a relatively early stage of development eligible but should ensure parity between the T&S pathways. By creating parity, this would avoid developers evidencing a direct route to store, when a T&S network under development has already completed more investigation of a suitable T&S solution and is therefore a more reasonable option.

We propose that passing this T&S test remains mandatory. Our view is that demonstrating a feasible route to an area of deep geological storage offshore, in addition to a suitable transport and storage infrastructure or CO_2 T&S network, is a less burdensome test to meet than demonstrating connection to limited hydrogen infrastructure in the short-term. By making the

64 https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/43609/Carbon_capture_readiness_-_guidance.pdf

T&S test mandatory to pass, and the hydrogen test not mandatory to pass, we are intending to ensure parity between the HCR and CCR requirements and reflect the corresponding technologies. As with the hydrogen fuel access test, the test for connecting a combustion power plant to a CO_2 transport and storage network needs to strike a balance between: ensuring plants do not become stranded as they are unable to access the infrastructure necessary to decarbonise; and limiting the burden the test places on developers, potentially creating a barrier to entry. Our intention would be to review the effectiveness of CCR transport and storage (T&S) test alongside the hydrogen fuel access assessment as part of the proposed periodic reviews of DR requirements.

8.3.5.1 Non-pipeline transport (NPT)

Government recognises the importance of remote emitters being able to access CO_2 transport and storage networks. We consider that the capacity for T&S networks to be able to accept CO_2 from dispersed or distant sites and international sources by non-pipeline transport (NPT) will be important for achieving our long term decarbonisation objectives. We are continuing to engage with industry in order to understand the arrangements necessary to enable non-pipeline transport of CO_2.

For DR, we propose not to specify the mode of transport in the regulations, as is consistent with the approach taken in the 2009 CCR. However, we would provide instructions to the EA to retain the option for shipping, expanding guidance to provide more support to developers including this transport solution. Submissions including shipping would require, among others, the demonstration that there are no barriers to compliance with all the relevant safety factors involved in loading CO_2 onto a vessel.

We do not propose to include road and rail in the guidance now. We believe that technological development and regulation is not sufficient to ensure that this would be a meaningful assessment. The inclusion of road and rail may otherwise undermine the T&S test.

8.3.5.2 Usage

We do not intend make provisions for CO_2 usage in the legislation or guidance at this stage. Usage that does not result in the permanent storage of CO_2 will not lead to decarbonisation and is therefore not compatible with the objectives of DR. Usage that results in permanent storage has been considered, but we are not taking this forward as an option at this stage. This decision was taken due its impact on the T&S test, the relative lack of technological development and research of alternative forms of permanent storage where a product is created from CO_2 for use, and specifically the lack of information on the monitoring of these uses to ensure that this CO_2 storage remains permanent.

We believe that CO_2 usage (that results in permanent storage) generally aligns with the principles of DR and may be an economic option in the future. We have seen an acceleration of innovation in this sector and therefore we intend to evaluate this position at the next review of DR. Any future proposal would also need to carefully consider how meaningful any submitted solution would be, given that it may nullify many of the requirements of the currently proposed T&S test.

Consultation Question 22

Do you agree with our overall proposals for CCR? In your answer please also outline whether you agree with the proposed changes to the technical feasibility test, economic feasibility test, and the space requirement?

Consultation Question 23:

Do you agree with our proposed updates to the transport and storage test?

9. Impacts

9.1 Background

In our call for evidence, we sought evidence from stakeholders on the potential impacts of implementing the proposed Decarbonisation Readiness (DR) requirements to help inform the development of an Impact Assessment which has been published alongside this consultation.

Government welcomes the responses received, and these have been used to inform our policy development, including our Impact Assessment.

A summary of responses to the call for evidence questions is below:

9.2 Summary of responses to the call for evidence

Call for Evidence Question 27:

What impact could the changes discussed in this call for evidence have on your business's administrative costs for planning permission and environmental permitting? Please specify which of the proposed changes will have the most impact.

Question 27 received 19 direct responses with three responses suggesting that additional cost identification is either too early to comment, those costs could be minimised if incorporated in existing processes or indeed the cost of not delivering low carbon power generation would be greater financially. There were multiple comments on which of the proposed call for evidence changes will have the most impact, which in order of magnitude were: a) permitting fees and administrative costs such as undertaking studies or commissioning external consultants, b) the potential for delays in the permitting process, c) increase in investment risk due to uncertainty over changed requirements and the likelihood of meeting them, and d) costs of the Capacity Market (CM) and ancillary services if developers try to recover the additional costs through these markets.

The impact on smaller assets was raised as being potentially disproportionate. Additionally, it was noted that the current uncertainty on energy policy needed clarity to quantify impact along with policy stability.

Call for Evidence Question 28:

We anticipate developers are already considering future decarbonisation options following the Energy White Paper (EWP). What impact are the changes discussed in this call for evidence likely to have on your investment decisions for new build plant? Please specify which of the proposed changes will have the most impact.

There were 16 direct responses to question 28 with ten commenting that generators have decarbonisation strategies or are factoring market and policy signals into their financial assessments. However, the investment landscape is highly uncertain due to uncertainty around future technological and market developments. There were two comments suggesting it is too early to quantify. In addition to this, there were several proposed changes as per the call for evidence which were identified as being a potential influence on investment including (with no priority) onerous technical requirements or administrative costs, potential for regulations to change once an investment decision has been made, and the potential lack of flexibility to respond to market developments as they arise.

Call for Evidence Question 29:

How do you currently manage the long-term risks of decarbonisation in your investment decisions? What additional work will the proposed changes cause?

There were 13 direct responses in relation to question 29 with nine commenting that decarbonisation was already part of their respective review processes and investment strategies. It was also noted that investment decisions on existing assets are likely to be more short-term focussed given the uncertainties. As low carbon increases, the importance of stand by supply security may increase, impacting investment in embedded high carbon generators. It was also commented that the use of green hydrogen could reduce investment risk with additional comments requesting expert advice to be sought to steer the DR process and mitigate investment risk.

Call for Evidence Question 30:

Are there any specific impacts on small and micro businesses that are not covered above? If so, please provide details of the anticipated one-off and on-going costs.

Question 30 received 12 direct responses with no general consensus beyond recognition of the impact on smaller business relative to the regulatory requirements. There were several comments proposing multiple barriers to micro to small business, consisting of (in no particular order), costs of option analysis, inherent delays, permitting, capex costs, increased consultancy and the regulations themselves. There were several comments suggesting the process needs to be appropriate to ensure these businesses are not over stretched with onerous legislation as some of these apply to critical supply systems such as those delivering power to data centres, hospitals, and other life dependent systems.

Call for Evidence Question 31:

Please tell us if you think there are any other impacts not covered above, in particular wider impacts on the energy system and security of supply

Question 31 received 16 direct responses with the main consideration being a reiteration for a clear need for consistency and clarity in understanding risk, timescales, security of supply and costs. It was also implied there is some level of dependency upon the review process and expectations on consistent wider interconnected policy to deliver that. In addition, there were multiple comments concerning other potential impacts which included: higher network costs, apprehension of policy expectation on possibly mandating CCUS, that blue hydrogen use may prove to be counter-productive, a clear need to drive renewables in parallel and to emphasise solid fuel power generation more within DR. Lastly it was stressed that the process required investment inducement to ensure progressive sustainable development.

Consultation Questions

1. Do you agree with Government's proposal for the definition of "fully decarbonised"?

2. What are your views on our proposals that eligible combustion power plants would be subject to Decarbonisation Readiness requirements unless they can demonstrate they have met the definition of being "fully decarbonised"?

3. Do you agree with the three proposed objectives of the Decarbonisation Readiness requirements?

4. Do you agree with our proposal to remove the 300 MW threshold and to align the scope of decarbonisation readiness with the existing scope of environmental permitting for combustion power plants?

5. Do you agree with our proposals to include both new build and substantially refurbishing plant within scope of DR? What are your views on using the definition of "substantially refurbishing" from the environmental permitting legislation in the context of DR?

6. Do you agree with enabling existing plants to voluntarily submit a DR report?

7. Do you agree with our proposals to include biomass, EfW and CHP in DR?

8. What are your views on including heat generation in DR at a later date?

9. Do you agree with our proposed approach to exemptions from DR requirements?

10. Do you agree with our proposed approach to transitional arrangements from DR requirements?

11. Do you have any comments on our proposal to move the DR requirements to the environmental permitting regime?

12. How do you see the proposed changes impacting the planning system (Nationally Significant Infrastructure Projects (NSIP) and/or Town and Country Planning Act (TCPA) regimes), including decision, and plan-making?

13. Do you agree with our proposed approach to DR appeals?

14. Do you agree with the proposal for developers of eligible plants to submit update reports every two years from the start of their combustion power plant's operations? What are your views on what the report should cover?

15. Do you agree with our proposal for a regular review of Decarbonisation Readiness requirements as part of any review carried out and report published under regulation 80 of the Environmental Permitting Regulations 2016?

16. Do you agree with our proposed outline for a hydrogen readiness space requirement test?

17. Do you agree with our proposed outline for a hydrogen technical feasibility assessment?

18. Do you agree with our proposed outline for a hydrogen fuel access assessment, and our proposal to make it non-mandatory to pass in the short-term?

19. Do you agree with our proposed outline for a hydrogen economic feasibility assessment, and our proposal to make it non-mandatory to pass in the short-term?

20. Do you agree with Government's proposal to require all eligible new build or substantially refurbishing combustion power plants which opt to meet DR requirements through hydrogen conversion to also have to demonstrate capability of burning 100% hydrogen if they are put into operation after 1 Jan 2030?

21. Do you agree with Government's position of not requiring demonstration of plants' capability of burning a blend of hydrogen?

22. Do you agree with our proposals for CCR? In your answer please also outline whether you agree with the proposed changes to the technical feasibility test, economic feasibility test, and the space requirement?

23. Do you agree with our proposed updates to the transport and storage test?

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