Department for
Business, Energy
& Industrial Strategy

Carbon Capture, Usage and Storage

Government response to consultation on the Dispatchable Power Agreement business model

November 2022

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Introduction

In the Net Zero Strategy[1], government set out the ambition to bring forward at least one power CCUS plant in the mid 2020's through the CCUS Cluster Sequencing Process, and reconfirmed our commitment to implement the Dispatchable Power Agreement (DPA). This is an important part of working towards the government ambition of ensuring that all generation is from clean low carbon sources by 2035, subject to security of supply.

The DPA is the proposed contractual framework for power Carbon Capture, Usage and Storage (CCUS). It is based on the Contracts for Difference (CfD) for Allocation Round 4 ("CfD AR4") standard terms and conditions but has been adapted to enable natural gas fuelled power CCUS facilities ("Project") to play a mid-merit[2] role in meeting electricity demand, displacing unabated thermal generation plants.

In April 2022, the government published a consultation to seek views on the proposed DPA business model and associated full draft DPA Conditions and DPA Front End-Agreement [3], prior to the negotiation / due diligence phase of the Track-1 Phase-2 of the Cluster Sequencing for Carbon Capture Usage and Storage deployment process. The draft DPA had been developed since the publication of the initial DPA business model update in December 2020[4] and following engagement with CCUS expert groups, industry, and relevant regulators.

This document sets out the government's response to the views gathered as part of the DPA Consultation (as defined below) and has been published alongside: (i) the DPA Business Model Summary (November 2022); (ii) DPA Front End Agreement; and (iii) DPA Conditions ((ii) and (iii) together referred to as the **"November DPA"**), published in connection with this document in November 2022[5].

Overview of consultation proposals

The consultation on the DPA business model and draft DPA was published on 12 April 2022 and closed on 10 June 2022 (**"DPA Consultation"**). The consultation comprised of twelve questions, inviting views on the suitability of the proposed DPA business model for: incentivising efficient decarbonisation; ensuring that a Power CCUS Facility responds to electricity market price signals and consumer needs by providing flexible and mid-merit dispatchable output; incentivising investment in new build, re-powering and retrofit Projects alike; ensuring that risk is fairly allocated to enable investment in Projects and value for money for consumers; ensuring there is appropriate testing of a Facility's performance; and preventing overcompensation through a proposed gainshare mechanism.

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[1] Net Zero Strategy: Build Back Greener (October 2021).
[2] In the context of electricity generation, the term 'merit order' refers to the sequence in which power generation plants are designated to deliver power to the grid, from cheapest to most expensive.
[3] Carbon capture, usage and storage (CCUS): Dispatchable Power Agreement business model (April 2022).
[4] Carbon capture, usage and storage: an update on business models (December 2020).
[5] Carbon capture usage and storage (CCUS): business models.

The questions sought to determine the extent to which the proposed business model and draft Contract met the principles guiding the design of the power CCUS business model, specified in the December 2020 DPA update.

Engagement with the consultation proposals

Responses to the consultation were submitted through an online response tool (Citizen Space), or by email. The consultation received fourteen responses, out of which nine were from operators of power generation facilities or projects and three were from trade association bodies. The remaining responses were from a consultancy firm and a Charitable Foundation.

To aid stakeholders' understanding of the consultation proposals, BEIS officials hosted a Power Industry Working Group roundtable event on 13 May 2022.

The consultation applied to Great Britain given that, initially, the DPA is designed to operate in Great Britain only. Electricity Generation is a devolved policy area in Northern Ireland, with responsibility resting with the Department for the Economy.

Next steps

The policy positions set out in this government response alongside the DPA Business Model Summary (November 2022) and the November DPA, are indicative only and do not constitute an offer by government and do not create a basis for any form of expectation or reliance. The government reserves the right to review and amend its positions and proposals, for any reason and in particular to ensure that proposals provide value for money (VfM) and are consistent with the current subsidy control regime.

On 12 August 2022, the government published the list of Power CCUS, Industrial Carbon Capture (ICC), Waste and CCUS-enabled hydrogen projects[6] that have proceeded to the due diligence stage of the Phase-2 Cluster Sequencing process. This shortlist follows the selection of the HyNet and East Coast Clusters as Track-1 clusters in November 2021. Projects underwent a rigorous assessment process and the publication of the shortlist marked a significant step towards realising our ambition to deploy CCUS in at least two industrial clusters by the mid-2020s (as per the Ten Point Plan for a Green Industrial Revolution[7] and the Net Zero Strategy) and to bring forward at least one power CCUS plant in the mid 2020's.

In the Net Zero Strategy, we also announced our ambition to begin competitive allocation for Power CCUS Projects in the 2020s. To gather views and evidence on how best to achieve this ambition and support the continued deployment of Power CCUS projects into the 2030s, we launched a call for evidence on 25 July 2022 which closed on 17 October 2022. This call for evidence was focussed on how we can best develop our future policy framework to support the continued deployment of Power CCUS projects beyond the first Track-1 project(s).

[6] Cluster sequencing Phase-2: shortlisted projects (August 2022).
[7] The Ten Point Plan for a Green Industrial Revolution (November 2020).

The government has made amendments to the Contracts for Difference (Allocation) Regulations 2014 and the Contracts for Difference (Definition of Eligible Generator) Regulations 2014, following consultation, to ensure these existing regulations under the Energy Act 2013 can be used to award DPAs. The amendments will allow for retrofitted CCS generators to be eligible, allow for an alternative payment mechanism, and allow for non-pipeline transport methods of CO_2 to be used if required. The resulting Contracts for Difference (Miscellaneous Amendments) Regulations 2022[8] came into force on 21 June 2022. Government is considering what amendments might be required to the Contracts for Difference (Electricity Supplier Obligation) Regulations 2014 in order to support the DPA payment model.

[8] SI 2022/691

Responses to the consultation

This government response summarises the feedback received from the fourteen respondents to the consultation and outlines the policy responses. The government is grateful to all respondents for taking the time to respond to the consultation and provide their views. In developing the policy responses, government has carefully considered the responses received, consulted with external advisors, and taken into account the policy aims of the business model.

Question 1: Do you agree that the proposed Availability Payment component of the DPA Contract incentivises efficient decarbonisation and best in class carbon capture technology selection? If not, what changes do you think are necessary to facilitate this?

Summary of responses:

Most respondents agreed that the proposed Availability Payment component of the DPA does in fact incentivise efficient decarbonisation and best in class carbon capture technology selection.

Several respondents raised concerns about using the Deemed Rate, suggesting it would disincentivise generation during periods of low availability and that the risk associated with performance drops would be priced into the marginal cost or undermine the effect of the Variable Payment. These respondents indicated preference for a simpler Achieved Capture Rate and declared rate system. Some raised concerns about a lack of information regarding how the Availability Payment Rate will be set, and one respondent suggested that new-build projects and retrofit projects should be assessed separately to give possibilities to both types of Project and to take into account their specific requirements.

Some respondents did not agree that the proposed Availability Payment incentivises efficient decarbonisation and best in class carbon capture technology selection; and suggested changes such as having a grace period during early production phase, softening the termination rights and the technical criteria and thresholds for testing regime only being finalised during negotiation and due diligence phase. A small number of respondents highlighted that a high average capture rate might be difficult to achieve if a Generator is often starting up and shutting down, with one respondent emphasising that the Termination for Minimum CO_2 Capture Rate Breach may affect Generator dispatch decisions. Responses to Question 2 also addressed additional costs associated with start-ups.

Many respondents suggested that Availability of Generation and Availability of Capture should be assessed independently. One respondent requested increased flexibility in relation to the annual NDC testing period. Another suggestion was adding a mechanism that reconciles DPA payments with Capacity Market payments which allows projects to transition from one to another, while a different respondent asked for clarification on how the DPA might interact with Capacity Market agreements at the beginning and end of the DPA.

A small number of respondents suggested that the DPA should include a provision to cover risks associated with the potential for fuel supply of a Power CCS facility to include a portion of hydrogen in the future, suggesting that this could decrease the CO_2 concentration of the flue gases, reducing the effective capture rate of the plant.

Two respondents proposed that the definition of Generation Outage Relief Events should be extended to include those outages arising from the connection with the T&S Network.

One respondent raised concerns that the definition of a Generation Outage Event sets a threshold for outages of 1MW, stating that even under stable operation on a standard CCGT at Full Load, variations in output of up to 1% are not uncommon and that reporting of all >1MW deviations could be time consuming to report and does not appear to be a proportionate measure of availability. The respondent suggested that a different approach may be needed to define a Generation Outage Event and proposed an alternative calculation for determining the Availability of Generation.

Government response:

We have carefully considered the feedback from several respondents that determining the Availability of Capture by considering a Deemed CO_2 Capture Rate, based on a historic average capture rate, during non-operational periods would introduce risk that would be priced into dispatch decisions, and may result in reduced load factors for a DPA Facility. Some respondents proposed that a better system for calculating the Availability of Capture would be a simpler system which uses the Achieved Capture Rate for settlement units where the facility was dispatching electricity (operational periods), and the Declared CO_2 Capture Rate for settlement units where the facility was not (non-operational periods), or where there was a T&S Outage.

We identified that the combination of the Declared CO_2 Capture Rate during periods of poor capture performance and the Deemed CO_2 Capture Rate during the subsequent twelve months had the effect of double counting reductions in capture performance, and therefore could incentivise a Generator to shut off during periods of poor capture performance even when it had a lower short-run-marginal cost and would be emitting a smaller quantity of carbon dioxide than the best in class unabated alternative. Since the consultation was published, we have further developed the declarations system for the Declared CO_2 Capture Rate and propose, in line with consultation comments that the 12 month historic rolling average is removed in favour of using Declared CO_2 Capture Rates only when Achieved CO_2 Capture Rates are not used for the Availability of Capture.

We have therefore adjusted the calculation of the Availability of Capture in the DPA to include this mechanism. More detail on the calculation of Availability of Capture is set out in the Payment Mechanism section of the DPA Business Model Summary document, while more detail on how Declared CO_2 Capture Rates will function are outlined in the Representations and Warranties section.

We acknowledge that a 1MW threshold for defining Generation Outage Events may be too granular for the purposes of calculating Availability of Generation (AG). Therefore, we have amended the contract threshold to define Generation Outage Event as an event where the Facility is unavailable, curtailed or derated such that the NDC is reduced by an amount greater than one per cent (1%) of NDC. We have also amended the definition of a Generation Outage Event to clarify that they refer to outages corrected to Reference Site Conditions (as defined in the DPA).

To minimise the cross-chain risks of a T&S outage event, we have designed mechanisms to preserve a Generator's Availability Payment where the T&S outage is caused by an event outside of its control, via the Outage Relief Event provision. The AG term in the Availability

Payment formula covers outages which remove generating capacity available to the Electricity System Operator (ESO), rather than economic decisions to not dispatch. Therefore, we have not expanded the definition of Generation Outage Relief Events to include outages arising from disruption to the T&S Network connection. We recognise that there may be some concerns around Environmental Permitting and the ability to operate a Power CCUS Facility in an unabated mode, which we have covered further in our response to Question 4.

We have reviewed the feedback regarding the independence of the Availability of Capture (AC) and the AG terms but believe that the approach to AG set out in the consultation document and AC set out above is appropriate. The AG term and the Availability of Capture term are assessed fully independently – in the former case, with reference to UK REMIT outage declarations, and in the latter with reference to the calculated Achieved Capture Rate or Generator Declared Capture Rate. In circumstances where events affect both the ability to generate (AG) and capture (AC) then it is reasonable that proportionate reductions to both the AG and AC calculations are made to accurately reflect the availability of low carbon generation being provided by the Generator in the relevant Settlement Unit.

The DPA is designed to support both new build and retrofit projects alike. The Cluster sequencing guidance[9] sets out in section 3.3 the evaluation criteria used to assess power CCUS submissions for Phase 2. The evaluation criteria consider factors pertinent to establishing initial industrial clusters rather than a direct comparison of the pros and cons of new build projects versus retrofit projects in isolation.

The DPA is intended to initially be deployed as part of a wider Cluster Sequencing Process. Track 1 of this process is ongoing, and dispatchable Power CCUS projects had an opportunity to apply as part of Phase 2, which was open for applications between 8 November 2021 and 21 January 2022. As part of this process, applicants will be assessed based on their Availability Payment Rate (APRi) bid, and the Initial Availability Payment Rate will be agreed prior to the Agreement Date through this process. In July 2022, we launched a call for evidence which considers the future policy framework and allocation of DPAs (as discussed above). The process for assessing DPA applicants is outside of the scope of this consultation.

Further feedback on the interaction between the DPA and other support schemes, such as the Capacity Market, was received in response to Questions 4 and 5 of the Consultation and we have responded accordingly below.

It is acknowledged that in the future, if natural gas fuel supply is blended with hydrogen, this could have implications for plant performance depending on the concentration of hydrogen that is introduced to the gas network. Government will continue to consider this issue and discuss with shortlisted projects in upcoming negotiations.

[9] Cluster Sequencing for carbon capture, usage and storage (CCUS) deployment: Phase-2 (closed to applications)

Question 2: Do you agree that the proposed Availability Payment and Variable Payment in the DPA Contract will ensure that a power CCUS Facility reacts to electricity market price signals and provides dispatchable output without incentivising it to generate at all times thereby displacing lower cost and lower carbon generation sources such as renewables and nuclear? If not, what amendments do you consider necessary to achieve this objective?

Summary of responses:

Some respondents suggested that interconnected unabated plants could dispatch ahead of DPA facilities, as they avoid Carbon Price Support (CPS) and UK ETS costs.

One respondent proposed that any future merit order interaction with new forms of dispatchable power, for example hydrogen power, should be considered.

Some respondents suggested that under the current design of the Availability Payment, Generators could be exposed to a risk premium (i.e. the Generator's assessment of risk which can influence the pricing of the Facility in the market and can include the potential for Facility failure measured against future earnings potential) that is greater than that of the reference plant. In some cases, this could lead to the unabated plant setting a lower price than that of the DPA plant, causing it to dispatch ahead. Respondents proposed that there could instead be an availability target allowed over an aggregate period to signal to the Generator to make the Facility available whilst also reducing the risk premium, or that the Deemed CO_2 Capture Rate mechanism could be removed and the Declared CO_2 Capture Rate mechanism used instead. One respondent suggested that the Availability Payment should be linked to availability targets for CO_2 capture rates over some aggregate periods instead of the Availability of Capture mechanism.

Some respondents raised that in circumstances where the outcome of the Variable Payment calculation is zero, the T&S Flow Charge (formerly Volumetric Charge) would act as a direct variable cost that increases the short run marginal cost of power CCUS facilities, affecting dispatch profiles. One respondent raised technology specific concerns related to the variable payment, noting that the gas cost differential is negative for facilities which are more efficient than the reference plant and setting out that the current variable payment mechanism does not account for oxygen costs.

A small proportion of respondents raised that as the Variable Payment does not take into account additional start-up costs between the Power CCUS Facility and the Reference Plant, there is a risk that DPA plants will potentially not react appropriately to electricity market signals in some circumstances, such as short peak time periods. Additional start-up costs were also commented in the responses to Question 3.

A small number also noted that the Generator could retain the full upside benefits in cases when saved/reduced UK-ETS costs are greater than gas and other operating costs of the capture unit, as they would not be required to pay this negative element of the Variable Payment to the DPA Counterparty. Respondents elaborated that the gainshare mechanism only prevents over-renumeration over a threshold IRR level and that any over-compensation over such a level may only be returned several years later.

One respondent fed back that while the VP is based on day-ahead prices, projects will in practice hedge their commodity purchases which may mean unabated gas runs before a power CCUS facility in some cases.

One respondent fed back that the DPA should stipulate a degree of flexibility that projects must meet. Another respondent felt that future rounds of assessment of DPA applicants should consider the efficiency of projects. One respondent noted that the Variable Payment is based on base performance assumptions which are fixed at contract signature, and that the impact of material changes to plant performance could alter the effectiveness of the VP. Another respondent noted that updates to the T&S Charging Rates should be factored into the payment mechanism.

Government response:

We consider it appropriate to include CPS in the calculation. We recognise that in some circumstances electricity from interconnected generators in other countries will be dispatched onto the UK electricity system ahead of electricity generated by a facility which holds a DPA due to differing dispatch economics, including being exposed to different emissions tax regimes. The Variable Payment is designed to account for the difference in costs between the Generator and an unabated equivalent reference plant, which arise from installing carbon capture equipment, and not to ensure that the Generator dispatches ahead of interconnected generation. It would present significant challenges and add substantial complexity to the DPA to include a mechanism to incentivise a Generator to dispatch ahead of higher-carbon interconnected generation. Such a mechanism would have to accurately correct for differing dispatch economics, and so we do not consider it to be appropriate to include in the DPA.

We welcome feedback that we should consider potential interactions with other dispatchable technologies, such as hydrogen to power. The Variable Payment is designed to subsidise the difference in costs between the Generator and the reference plant, an unabated equivalent best-in class CCGT, bringing a Power CCUS facility in line with the best-in-class natural gas generation on the system. Both gas CCS and hydrogen to power can provide low carbon dispatchable power which will be key to meeting government's ambition of having all generation from clean sources by 2035. We are actively exploring the need and case for further market intervention to support hydrogen to power. In addition, in our recent call for evidence on Power CCUS, we sought views and evidence on the interaction with other technologies, such as hydrogen to inform future policy thinking.

Following the feedback on how risk related to the Availability Payment may be factored into generator dispatch decisions, and the feedback to Question 1 above, we have made the changes to the calculation of Availability of Capture to mitigate this risk. These changes are set out in response to Question 1.

We recognise that in circumstances where a Generator has a lower short-run marginal cost than a best-in-class equivalent unabated reference plant, the Variable Payment will not be paid and therefore the T&S Flow Charge (formerly the T&S Volumetric Charge) will be a direct variable cost faced by the Generator. In June 2022, BEIS published a 'Draft: Carbon Capture, Usage and Storage Network Code Indicative Heads of Terms'[10] and accompanying explanatory note which sets out more details about the T&S Charges. The indicative Heads of

[10] Draft: carbon capture, usage and storage network code indicative heads of terms: June 2022

Terms set out that T&S Charges, including the T&S Flow Charge, are intended to be based on charging rates set out annually in a T&S Charges Statement. The T&S Flow Charge Rate should be known in advance and hence be able to be taken into account when assessing the economics of dispatch decisions. It should be noted that these Heads of Terms are indicative only and government is doing further work to develop the CCS Network Codes.

We set out in the May 2021 update that we do not intend for the DPA to provide any specific compensation to a Generator related to additional costs incurred during start-up by a Facility relative to an unabated equivalent plant. Best Available Technology guidelines set out that Generators are expected to maintain a high capture rate throughout start up, and we encourage generators to consider what mitigations they can take to reduce start up costs.

We set out in the December 2020 update that a floor of £0 would be applied to the Variable Payment, and that a Generator would not have to repay any upside if its cost of generation was naturally below that of the unabated reference plant. We consider this position appropriate as in these scenarios the Generator can offer low carbon electricity for cheaper than an unabated higher carbon alternative, and electricity consumers will benefit from this. Applicants for a DPA in Phase-2 of the cluster sequencing process have factored in potential market revenues, including the market revenues that Generators can generate from this upside, into their Availability Payment Rate bids, reducing the total cost of the DPA to electricity consumers.

Further feedback on the gainshare mechanism was received in response to Questions 10, 11 and 12 of the Consultation and we have responded accordingly below.

Question 3: The objective of the Variable Payment is to incentivise a power CCUS Facility to dispatch ahead of an unabated reference Plant. Do you agree that the proposed Variable Payment mechanism achieve this? If not, what further amendments do you consider necessary to achieve this objective? Please provide your reasoning.

Summary of responses:

Some respondents suggested that the Variable Payment should account for actual additional costs incurred by a DPA plant compared to the Reference Plant, using metered information ex-post. Respondents noted that this could mitigate the risk of the unabated plant having a lower short-run marginal cost which could occur due to several reasons, including the effect of start-up costs as mentioned above.

A small number of respondents also proposed that the DPA should include a cost advantage which is just the right amount to encourage abated operations ahead of unabated, noting that the additional margin could reduce the impact of any risk premium associated with the Availability Payment mechanism, as discussed above.

One respondent also indicated that to ensure the VP functions correctly, the Base Assumptions of the Facility should be based on the loss-adjusted metered electricity output.

A few respondents indicated that the efficiency of the Reference Plant should only be able to be increased, with one respondent conversely stating that reference plant efficiency updates should be bi-directional to ensure the Variable Payment does not overcompensate. Some respondents suggested more clarity on the reference plant definition was required, such as explaining the basis for the defined thermal efficiency of 62.4% on a lower heat value basis

(LHV) for the proposed Initial CCGT Reference Plant and providing information on the reference plant beyond efficiency.

A small number of respondents asked whether degradation of a plant's capacity over asset lifetime is considered in the Variable Payment. A small proportion also flagged that at lower load factors of generation, the Variable Payment would not necessarily function due to efficiency decreases.

One respondent raised that there is a lack of recognition of locational specific costs in the Variable Payment which could potentially create a disparity between the CCUS assets, citing the gas transportation cost as an example of a locational specific variable cost.

One respondent asked for clarification over the indexation of costs in the Variable Payment, and raised concerns that individual costs included in the Other Extra Variable Costs term may change in a way that is not reflected by a general measure of inflation. One respondent provided feedback about the suitability of the reference plant for OCGTs with post-combustion capture, and another raised concerns that Power CCUS facilities could dispatch before biomass power generation.

The responses also reiterated feedback about additional start-up costs which has been responded to in Question 1.

Government response:

We have reviewed the feedback that the Variable Payment could be more effective if it included an ex-post assessment of costs rather than being calculated based on a set of base performance assumptions, however, we don't intend to adjust the VP in this way. As the Variable Payment is designed to compare the cost differential between a Generator and the theoretical unabated Reference Plant, such a mechanism would require us to also assess an equivalent set of theoretical ex-post costs for the Reference Plant for each VP Billing Period, and any mechanism to do this would introduce significant complexity to the variable payment and risk being inaccurate when compared to the costs of real life unabated equivalent CCGTs as the DPA Counterparty will not have direct access to the commercially sensitive cost data of these facilities. Such a mechanism would also risk reducing value for money for consumers, as it may reduce incentives for a Generator to minimise their cost of generation through investment and appropriate maintenance, and expose consumers to the costs of reduced efficiencies.

We have considered the feedback that the Variable Payment should include a built in cost-advantage to incentivise Power CCUS Generators to always dispatch ahead of an unabated equivalent plant, and have decided not to update the Variable Payment calculation to include this. We are confident that the current calculation of the Variable Payment, which intends to equalise the short-run marginal cost of the DPA facility with that of the unabated reference plant is sufficient to achieve the policy goal of incentivising power CCUS facilities to dispatch ahead of unabated equivalent plants, and that paying an additional price advantage would not be consistent with our aim to maximise value for money for electricity consumers, and would risk the subsidy no longer being proportionate to the subsidy goals.

After reviewing feedback around the use of the Loss-Adjusted Metered Output in the Variable Payment we have updated the contract to clarify that the Base Assumptions which feed into the Variable Payment should be set out per MWh of net generation capacity, not factoring in any transmission loss. We have carefully considered the calculation of the Variable Payment, which is designed to subsidise the additional costs associated with the parasitic load of carbon capture and concluded that, as these additional costs are faced per MWh of generated electricity, not per MWh of electricity transmitted, it is appropriate to pay the Variable Payment on each metered MWh of electricity that is generated, without adjusting it for transmission losses. We have therefore updated the Variable Payment, introducing a new definition of Metered Day Electricity Generated which is not loss adjusted.

We have reviewed feedback from multiple respondents about the Reference Plant Review process for making changes to the performance assumptions for the Reference Plant, with some respondents emphasising that the Reference Plant efficiency should only be increased in the Reference Plant Review, and one respondent suggesting that it should be able to be decreased if more efficient unabated facilities are no longer part of the GB electricity market. We consider that in order to provide certainty to Generators, it is appropriate to maintain the position in the April 2022 update and we confirm that the efficiency of the Reference Plant will only be increased through the reference plant review process. This has been clarified in the contractual wording.

We are grateful for feedback that further clarity is needed on the definition of the Reference Plant, in particular clarity on how we arrived at our proposed Reference Plant Efficiency of LHV of 62.4%. This figure comes from the government's Electricity Generation Costs 2020 report. This translates as a carbon intensity of 0.3265 tCO_2/MWh, which we will use as the Reference Plant CO_2 Emissions term and we will use 60.714 therms/MWh as the Reference Plant Gas consumption which we arrived at based on Reference Plant Efficiency of 56.2%, Gross Calorific Value (GCV) basis based on Electricity Generation Costs 2020 report[11] published in August 2020, and natural gas carbon intensity of 183.52gCO_2 per kWh, GCV-fuel based on Data Table 2a of the Green Book supplementary guidance: valuation of energy use and greenhouse gas emissions for appraisal[12], updated on 15 July 2021. The first Reference Plant Review Process is expected to take place in 2027, which we anticipate will be before the first DPA recipient will be operational, to account for any new best in class unabated CCGT.

We understand the feedback in the consultation that the effectiveness of the Variable Payment may be reduced over time if the DPA Generator's efficiency degrades, or if the DPA facility is exposed to lower load factors and subsequently has to face start-up costs more often, and have assessed options for mitigating these concerns. We do not intend to update the Generator's base performance assumptions in the Variable Payment over time because we consider that the degradation profile of a Power CCUS facility should not be significantly different to that of an unabated facility, and a mechanism to account for them would introduce significant complexity to the DPA. Any updates to performance assumptions would have to account for maintenance cycles and may result in over-compensation or disincentivise maintaining a high level of efficiency. We also consider that equivalent unabated facilities will also face lower load factors over time, limiting the impact of lower load factors on the effectiveness of the VP. We have set out in our response to Question 2 that we do not consider it appropriate to offer additional subsidy for start-up costs under the DPA.

We have reviewed feedback regarding location-specific costs, such as the TLM and TNUoS charges, which may be faced by Power CCUS facilities, but do not intend to adjust the DPA payment mechanism. The purpose of the Variable Payment is to subsidise additional costs

[11] BEIS Electricity Generation Costs (2020)
[12] Green Book supplementary guidance: valuation of energy use and greenhouse gas emissions for appraisal

faced by the Power CCUS facility compared to the theoretical reference plant, an unabated best in class natural gas facility otherwise subject to the same variable market signals.

We have set out the methodology for calculation of Other Extra Variable Costs indexation at condition 10.15 of the contract. In response to feedback querying the determination of Other Extra Variable Costs, this will be subject to negotiation and agreement with BEIS prior to the Agreement Date.

The consultation on the DPA focussed on natural gas fuelled thermal power generation plant with carbon capture technology only. Business models developed for carbon capture technology deployed on alternative thermal power generation plant including Biomass will consider the appropriate payment mechanism for that technology type.

Question 4: Are there any additional hurdles to a power CCUS Facility retaining the flexibility to respond to market conditions and consumer needs over the term of the DPA Contract considering foreseeable evolution of the power generation composition and demand profile over this time?

Summary of responses:

Most respondents raised concerns regarding whether unabated running was possible due to the associated planning process and environmental permitting regime risks. They also felt that the interaction between the CCS Network Codes and the DPA would be critical for assessing the capacity of Generators to dispatch flexibly, particularly in terms of how the Codes will deal with potential constraints on the network. It was noted that access to available T&S capacity was a critical pre-requisite to market-optimal dispatchable operation of a DPA facility.

One response set out that it was important that investors could rely on clear policy directions in relation to future participation of Power CCUS in the Capacity Market.

One respondent mentioned that having a gain share mechanism would distort market incentives and impact responses to market conditions – and noted that it was important that investors could rely on clear policy direction for future power market frameworks beyond the end of the DPA (such as the potential to participate in the capacity market after a DPA has ended). Further hurdles included the evolution of carbon price in the evolving ETS mechanism, transformations in the energy mix which could potentially reduce dispatchability and that the NDC Annual Testing Window should be extended to cover the winter period or aligned with the capacity market proving period.

Some responses provided a number of comments on the Change in Applicable Law and Qualifying Change in Law provisions in the DPA, noting that:

- it will be important for these provisions to be subject to flexibility during the DPA negotiation process to reflect updates in models, with a particular risk being the potential for change in law in relation to the T&S Network and CCS Network Codes which impacts on the Generator.
- The definition of a Foreseeable Change in Law was considered to be too wide, given FOAK nature of power CCUS and the number of existing consultation documents on policies affecting a range of UK policy including the CCUS programme, hydrogen networks, UK Emissions Trading Scheme, environmental permitting regimes and conservation zones.

- The definition of 'Specific Change in Law', while consistent with AR4 would not protect the Generator where a Change in Law indirectly affects its access to a necessary input for deployment or use of the CO_2 capture technology, or where a Change in Law affects the T&S Network.
- The definition of 'Specific Change in Law' should protect the Generator against future changes to CO_2 leakage liabilities.
- The definition of 'Specific Change in Law' should cover changes in law which specifically impact holders of a DPA, in line with equivalent protections for holders of a CfD.
- The definition of 'Other Change in Law', while consistent with AR4, sets a high bar for establishing a QCiL, and should not reference 'out of pocket costs' due to differences between the CfD and DPA payment mechanisms.
- The Comparator Groups under the DPA QCiL provisions do not provide adequate protection for the Generator and could therefore present a bankability risk given the following possibilities:
    - Specific CIL: Does not apply as the CiL only affects some, not all DPA generating facilities
    - Other CiL: Limb (A) does not apply as one other Generator is affected. Limb (D) does not apply as there are other Generators using the 'Facility's CO_2 Capture Technology' who are not affected.

  It was also requested that the definition of CO_2 Capture Technology used to define the Comparator Groups was subject to flexibility during negotiations.
- The Counterparty right to terminate under condition 27.3 if QCiL compensation reaches the compensation cap assumes that the Generator can close and decommission their Facility to avoid further QCiL costs which may not be the case.
- QCiL Construction and Cessation event costs should include all foregone DPA payment streams including debt payments and swap termination payments, and all financing costs, to promote bankability.

One respondent noted that the Change in Applicable Law provisions under the DPA introduces a parallel regime to reopen the contract wherein the Generator receives no compensation and should therefore be deleted.

One respondent asked why the Generator Tax Change in Law provisions included in AR4 had not been included in the DPA, and asked that they were reinstated.

Government response:

Due to the first of a kind nature of the CCUS programme at this scale in Great Britain, we recognise that if Power CCUS facilities cannot continue to operate during constraints or outages of the T&S Network, then such outages or constraints may cause a significant impact on project revenues. We will continue to engage across government to understand and explore other regimes and requirements, such as environmental permitting and planning consents, which impact how facilities operate. Although it is our intention to explore the matter further this should not form the basis of any expectation that changes will be possible or appropriate.

Further work to develop the CCS Network Codes is ongoing and we encourage industry to engage with this work going forwards. The Draft CCUS Network Code Indicative Heads of Terms and accompanying explanatory note, published in June 2022, set out more details about the Codes and how government intends to develop them.

The QCiL provisions in the DPA have been designed to protect the Generator from changes in law and broadly mirror those in the renewable CfD which are considered investable and bankable.

Further feedback on the gainshare mechanism was received in response to Questions 10, 11 and 12 of the Consultation and we have responded accordingly below.

Changes in the UK carbon price may affect the dispatchability of Power CCUS facilities, but downward pressure on prices would be accounted for in the DPA Variable Payment if the total Other Extra Variable costs, T&S Flow Charge and Gas and Carbon cost differentials produce a positive value (i.e. the DPA plant has higher total variable costs than the Reference Plant). If the UK carbon price increases then this should further incentivise Power CCUS facilities to achieve the highest possible capture rates to maximise market revenues.

While transformations in the UK energy mix could also affect dispatchability of Power CCUS facilities, we consider that these types of gas-fired power plants with CCUS can provide valuable flexible generation services, including ancillary services, to the UK power grid in a whole range of potential future UK energy mixes.

We have responded further on the NDC annual testing window approach in our response to Question 8 below.

With respect to the QCiL and CiL provisions under the DPA, we have the following comments:

General

- The QCiL provisions under the AR4 CfD apply to all Generators, irrespective of their technology type. Similarly, we expect the DPA provisions to be standardised across all DPAs and not subject to negotiation with individual Generators.
- In addition, certain thermal generation technologies are eligible for the CfD (e.g. biomass conversion, biomass with CHP, EfW with CHP, and advanced conversion technologies), and bespoke QCiL provisions have not been adopted in the CfD to reflect these technologies and their differing operational inputs.
- The Change in Applicable Law provisions are required in addition to the QCiL provisions as they account for situations where the contract is rendered illegal, invalid, unenforceable or inoperable, and as such, compensation would not be capable of remedying this. They are therefore an important set of provisions to ensure the continued operation of the DPA.

Foreseeable Change in Law

- We are following the definition of Foreseeable Change in Law in the AR4 CfD, and have not identified any material justification to deviate from this position.
- QCiLs are sector/technology-specific, as opposed to CiLs which impact all generators / UK businesses. For example, a new carbon emissions tax applying to all commercial and industrial consumers across the UK (i.e. it is not sector/technology-specific), would unlikely be deemed a QCiL.
- However, we recognise that there may be potential changes in law in which Generators may have particular concerns. We will be willing to consider proposals to the definition of "Foreseeable Change in Law" if the Generator can demonstrate: (i) the change in law will likely be implemented into UK law, (ii) would have a significant impact on DPA

Generators and their APRis (if left uncompensated); and iii) cannot be priced with sufficient certainty or in a way which represents VfM for consumers.

Specific Change in Law

- Specific Changes in Law are CiLs that apply specifically (and not merely indirectly or consequentially or by virtue of their disproportionate effect) to certain technologies that are distinguishable by reference to the nature of the technology and/or the subsidy support that such technology receives. This is separate to Other Change in Law which is designed to capture CiLs which are not directly discriminatory (i.e. which don't meet the bar set by the Discriminatory Change in Law) but when compared to one of the comparator groups it is clear that the CiL has had an undue and discriminatory effect on the generator's out-of-pocket costs.
- Changes in Law which expressly refer to or discriminate against generating stations with CO_2 technology (and not unabated facilities), would constitute QCiLs. Assuming CiLs which impact the T&S Network or affect CO_2 leakage liabilities apply to generating facilities with CO_2 Capture Technology and not other generating facilities, this would likely (depending on the relevant circumstances) be captured by limb (a) of the Specific Change in Law definition.
- We agree that CiLs specifically impacting DPA recipients should be added to the definition of SCiL. This will be reflected in the updated contract.

Generator Tax Change in Law

- We consider that a generation tax i) would not have an impact on a Generator's fixed capex/opex which is compensated through the Availability Payment; and ii) would apply to all abated and unabated CCGT generators and therefore would not change a DPA Generator's position in the merit order compared to unabated CCGT generators (and therefore would not necessitate an adjustment to the Variable Payment). In the CfD the Generation Tax Change in Law provisions recognise that changes to taxation laws are an ordinary business risk but provides protection for changes that are passed through in market price which would adversely affect CfD Generators over non-CfD Generators due to their fixed strike price. As there is no strike price in the DPA we do not think that this provision is necessary.

Other Change in law

- The concept of out-of-pocket costs has been carried across from the renewable CfD and applies to various provisions in the DPA in addition to the OCiL definition, e.g. see "QCiL Construction Event Savings" and "QCiL Costs". It is intended to capture actual cash which the Generator has to spend in order to meet the requirements of a QCiL. It is not intended to capture lost subsidy payments or lost revenue which are addressed separately through the new QCiL provisions in the DPA that compensate Generators for "QCiL Adjusted Revenues Payments" for QCiLs that affect the Availability of Generation, Availability of Capture and/or Net Dependable Capacity.

Comparator Groups

- We do not consider that a CiL could preclude the use of a certain CO_2 capture technology but only affect a limited number of the Generators who use that technology.

- An SCiL refers to a CiL "the terms of which specifically apply to: (A) generating facilities which deploy CO_2 Capture Technology, or CO_2 Capture Technology forming part of such generating facilities" but does not state that the CiL must affect all DPA generating facilities.
- We do not envisage that the definition of "CO_2 Capture Technology" will be negotiated during the DPA negotiations. This follows the position under the renewable CfD.
- We agree that CiLs non-DPA generators should be added as a comparator group to the definition of OCiL. This will be reflected in the updated contract.

QCiL Construction Event and Cessation Event Compensation

- The "QCiL Construction Event Costs" and "QCiL Operations Cessation Event Costs" definitions are both closely based on the renewable CfD, with the addition of specific provisions in the DPA to compensate Generators for lost DPA payments and lost revenue where a QCiL Operations Cessation Event occurs. We consider that these provisions, as drafted, are reasonable, appropriately allocate risk between HMG and the private sector, and are investable / bankable.
- However, as with the sizing of compensation in the event of Termination for Prolonged T&S Unavailability (see response to Question 7), we recognise that the addition of a forward projection of residual Facility value to the QCiL Construction Event compensation calculation could create a bankability risk. Therefore, we agree that the QCiL Construction Event compensation calculations may need to be amended to ensure that baseline debt obligations are fully compensated up front at a minimum, regardless of future value of the Facility. We will continue to review this, including using input from Phase 2 negotiations, noting that a full cost compensation with no consideration of ongoing Facility value could be excessively advantageous to the Generator.
- With respect to the Counterparty right to termination if QCiL compensation reaches the cap, as outlined in condition 27.3, these provisions reflect the equivalent provisions in the AR4 CfD (condition 34.3) and we have not identified any justification to deviate from this position.

Question 5: Do you agree that the standard terms and those project specific terms in the Front End Agreement of the DPA Contract are capable of equally incentivising investment in new build, re-powering and retrofit Projects alike? Alternatively, are there particular provisions which you consider require modification to facilitate investment in a particular type of Project (please explain why this is the case in your response)?

Summary of responses:

In relation to fulfilling the Milestone Requirement via the route of satisfying Project Commitments, a small proportion of respondents raised that the definition of “Material Equipment” in the proposed Front End Agreement lists equipment that “shall” be included in the set of equipment that the Generator is expected to have reasonably ordered and/or concluded a supply agreement to enable the Facility to be Commissioned at the start of the TCW. Respondents suggested that more open-ended language (than the use of ‘shall’) could allow for the deployment of alternative capture technology and take into account that retrofit projects may have some of the generation infrastructure already in place.

A respondent raised that moving the defined terms “Facility Shutdown” and “Full Load Operation” from the DPA Conditions to the Front-End Agreement would allow for technology specific definitions to be incorporated.

Regarding the Agreement Date representation on CO_2 capture in the draft DPA Conditions (Part 7 Representations, warranties and undertakings), a respondent noted that this should be removed as Generators should not necessarily be required to carry out due diligence checks on the T&S Network and its intention to permanently store CO_2, beyond the diligence that BEIS would do. Another respondent also suggested that this should be removed, as part of their response to Question 6 (please see Question 6 for further context).

One respondent questioned why the OCP Construction Reporting Requirements and Reporting Obligations Audit Right, included in the proposed Contract, are necessary. The respondent suggested that construction reporting could increase operating and project administration costs. The respondent also noted that although the Reporting Obligations Audit Right is in effect from the Agreement Date and until thirty calendar days after the start date, more than one Business Day notice should be required to commence the Audit, citing that an audit during plant commissioning and testing could be disruptive and create safety concerns at the Facility.

A respondent requested clarification regarding the Subsidy Control Declaration Operational CP, which requires Generators to confirm to the DPA Counterparty that no Subsidy, State aid and/or Union Funding has been received in relation to the costs of the Project (excluding the subsidy arising under the DPA) or that any such funding which has been received has been repaid in full to the granter of the funding. Specifically, the respondent requested clarification that this does not mean that a retrofit Project that has previously benefitted from other contractual arrangements or support schemes (e.g. CfD or Capacity Market) is excluded from DPA support.

One responded raised that the definition of T&S Termination Costs in the draft DPA Conditions should be simplified and made clear that it includes: all outstanding debt, other costs and fees payable under the project’s finance documents; invested but unpaid equity together with an expected rate of return; and unavoidable costs due to termination e.g. decommissioning costs and termination costs payable under the project's contracts.

One respondent raised that a longer contract term length should be considered for new-build projects as this could increase investor confidence and result in greater VfM for consumers by, for example, enabling the repayment of financing over a longer period of time. The respondent suggested that the economic and technical lifetime of a Power CCUS Project may exceed 15 years, the proposed maximum DPA term length, meaning that revenue certainty could reduce once the Facility has reached the end of its DPA and could result in early closure of the Facility.

A small proportion of respondents suggested that it is not appropriate for supply chain emissions to be applied to Greenhouse Gas Removal technologies but to not be accounted for in the renumeration for Power CCUS projects, expressing that supply chain emission thresholds should also be applied to all CCUS sectors to maintain consistent treatment.

Government response:

Government believes that the definition of "Material Equipment" as currently drafted is suitable to ensure that projects will take the required steps towards delivering the project and enable facilities to be Commissioned at the start of the TCW. This drafting in the Front End Agreement takes into account different technology types given that separate lists have been provided for post-combustion, oxy-fuel, and pre-combustion. However, government recognises that certain required equipment could already be installed, for example in the case of retrofit projects. Government understands that for retrofit projects, the definition of "Material Equipment" may need to be set on a project-by-project basis and agreed during negotiations, as set out in the Front End Agreement.

The defined terms "Facility Shutdown" and "Full Load Operation" will remain in the DPA Conditions, but government recognises that requirements may vary across different technology types. These definitions can be clarified during the negotiation process if necessary, and specific requirements can be accounted for in the Front-End Agreement.

Regarding the Agreement Date representation on CO_2 Capture, it should be noted that in order to be eligible for a DPA, Facilities must be connected to a "complete CCS system" which includes, in part, the disposal of captured carbon dioxide (or any substance consisting primarily of carbon dioxide) by way of permanent storage[13].

The Draft CCUS Network Code Indicative Heads of Terms outlines what a T&S Operator will need to comply with Regulatory Requirements relating to the operation of the T&S Network. This includes a permit, issued under the relevant regulations[14] under the Energy Act 2008, for the permanent storage of CO_2. However, in this contract between the DPA Counterparty and the Generator, the government considers that it is important for the Generator to also warrant, to the best of their knowledge, that the store it has connected to will permanently store the CO_2. This is not anticipated to be an additional level of due diligence that the Generator must undertake but it is important for the Generator to confirm their understanding of this requirement as part of the contractual process and to demonstrate the intention for CO_2 to be permanently stored. The Generator could, for example, make this warranty by delivering evidence to the DPA Counterparty that the T&S Operator holds, and continues to hold, a storage permit for the store that the DPA Facility has connected to.

The government does not consider this to be an onerous requirement on the Generator given that this would need to be represented and warranted "as far as the Generator is aware (having made all due and careful enquiries)" at the Agreement Date, rather than later in the contract term. There are provisions (including relief in some cases) in the DPA to mitigate against risks that might arise at other stages in the contract term relating to the transportation and storage of CO_2, e.g. due to T&S Outages, Force Majeure events, QCiL events, and T&S Commissioning Delay Events that are outside of the Generator's control. The Network Code Indicative Heads of Terms also states that the "title and risk in carbon dioxide delivered to the T&S Network at a Delivery Point in accordance with paragraph 1.1 shall pass to the T&S Operator at that Delivery Point". This should further indicate responsibilities for the ownership and storage of CO_2.

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[13] The Contracts for Difference (Definition of Eligible Generator) Regulations 2014

[14] The Storage of Carbon Dioxide (Licensing etc.) Regulations 2010, The Storage of Carbon Dioxide (Licensing etc.) (Scotland) Regulations 2011, The Storage of Carbon Dioxide (Licensing etc.) Regulations (Northern Ireland) 2015

Regarding reporting requirements in the DPA Conditions, the government considers that the OCP Construction Reporting Requirement is important for enabling the DPA Counterparty to be updated on the progress of Pre-operation Activities, which includes identifying at an early stage any risks or delays to pre-operation activity and potential remedial action. It is important for this to be included in the set of OCPs which must be fulfilled before the Start Date of the DPA can occur and before DPA payments can commence, given that the DPA support is only intended to be provided to Generators that are taking steps to deliver the Project and to work towards the policy objective. It is also important to monitor this progress given that government is seeking to develop CCUS in an integrated manner at a cluster-level, where the T&S Network and users of the T&S Network can impact each other.

Both this reporting requirement and the Reporting Obligations Audit Right have also been included in light of the DPA Counterparty's experience of administering the CfD and because projects supported by the DPA will be FOAK.

Regarding the Reporting Obligations Audit Right, it should be noted that it is the Generator's responsibility to comply with its reporting obligations and this Audit Right is exercised in cases where the DPA Counterparty considers it to be "reasonably necessary" to assess the Generator's compliance with OCP General Reporting Obligations and Construction Reporting Requirements. The position in the draft Contract which states that the DPA Counterparty can exercise the Audit Right no earlier than one (1) Business Day after the Generator's receipt of Audit Notice was derived from other and distinct audit rights in the CfD. However, government has taken into account the consultation feedback about this. This position has therefore been updated in the DPA Conditions such that the DPA Counterparty can exercise this Audit Right no earlier than two (2) Business Days after the Generator's receipt of the Audit Notice.

Government believes this provides sufficient flexibility for a Facility to mitigate any concerns around safety or disruption to activities, and it should be noted that two business days is the earliest that the Audit can commence following the Generator's receipt of the Notice.

In response to the concerns raised around the Subsidy Control Declaration OCP, we note that the purpose of this requirement is to ensure that Generators do not receive support under other schemes for the same elements of the Facility that are being supported under the DPA. This is to ensure compliance with Subsidy Control principles and to prevent overcompensation. We consider that the current drafting of "Project" mitigates the concern that a retrofit Project would need to repay historic funding received from other support schemes for original generation assets, given that the definition of Project refers to activity that is "pursuant to the DPA" specifically, i.e. for retrofits this would involve support for new capture assets and updating existing generation assets required under the DPA, rather than support for the original generation infrastructure.

However, we have carefully considered feedback relating to this and we additionally note that the definition of "Project" will be reviewed and may be amended by the Department for retrofit projects, to provide further assurance. This has been reflected in the contractual wording.

We have also introduced the defined term of "An Approved Scheme of Funding" to the Subsidy Control Declaration OCP and no cumulation of subsidy warranty requirements. This definition is expected to be relevant if any funding has been provided to the Generator and/or its Affiliates under the Industrial Strategy Challenge Fund and/or the BEIS Energy Innovation Programme for development/pre-development expenditure incurred in respect of the DPA

Project prior to the Agreement Date. Such funding will need to be notified to, and verified by, BEIS on a project-by-project basis and set out in the Agreement. It can be expected that such funding would not need to be repaid (subject to Subsidy Control Principles and the funding being correctly notified to, and verified by, the Department). BEIS is considering whether to refer to any other scheme(s) of funding.

However, any funding that has been received under "An Approved Scheme of Funding" shall be taken into account when calculating the subsidy arising under the DPA in order to prevent cumulation and overcompensation. The DPA Conditions and Front End Agreement, published alongside this document, set out this mechanism in greater detail.

Regarding the specific question of how the DPA may interact with the Capacity Market scheme, the DPA is being introduced to incentivise the deployment of the first power CCUS project(s) as part of Track-1 of the Cluster Sequencing process and Generators in receipt of a DPA in this form are prohibited from receiving subsidy for the Project through the Capacity Markets scheme, to ensure compliance with Subsidy Control Principles and to prevent overcompensation.

However, it should also be noted that as part of the call for evidence on the future policy framework for power with CCUS, we sought views and evidence on what the potential relationship between a future form of DPA and the Capacity Markets scheme could be going forwards, beyond the first Track-1 project(s). This thinking includes exploring whether it could be beneficial in the future for plants with an existing multi-year CM agreement to transition to hold a form of DPA (or alternative form of support) or whether it would be desirable to hold a combination of support mechanisms, providing that there are sufficient measures in place to ensure subsidy control compliance e.g. potentially through changes to the terms and conditions of any future DPA to avoid overcompensation. This call for evidence has closed but we encourage industry who are interested in receiving support for future CCUS projects beyond the first Track-1 projects to engage with this work on the future policy framework for power with CCUS going forwards. It should also be noted that options for the reform of the CM mechanism and wider electricity market arrangements were considered as part of the Review of Electricity Market Arrangements consultation[15].

We have responded in more detail to questions around the compensation in the event of a T&S Prolonged Unavailability Termination in our response to Question 7 below.

Regarding the term length for DPAs, government maintains the position that regardless of whether developing a new build, repowered or retrofit Project, Generators will have flexibility to choose an appropriate term length that is between 10 and 15 years. We consider that a term length between 10 to 15 years offers both an investible proposition and value for money for consumers. We set out in the October 2021 DPA Business Model Update that feedback from stakeholders was taken into account in the development of this position[16]. We also outlined that while longer contracts may help to provide greater investment certainty and may serve to lower annual costs to consumers, shorter contracts are likely to provide a lower overall cost to consumers across the term of the DPA. Longer contracts additionally provide greater certainty of generation capacity for the government. We consider that a term length of between 10 and 15 years strikes an effective balance between these competing considerations and offers

[15] Review of electricity market arrangements consultation
[16] Policy on term length is set out in more detail on page 8 of the Dispatchable power agreement (DPA) business model: October 2021 update

flexibility to account for the full range of potential Power CCUS projects. This approach can also enable term lengths to be proportionate to the remaining operational life of each respective Project. Government considers that the term length should not exceed 15 years to ensure that the DPA support is proportionate to the policy objective and complies with Subsidy Control Principles.

We do not consider that incorporating supply chain emissions as part of the DPA would support our objectives of incentivising Power CCUS plants to operate flexibly, dispatching after renewables and nuclear, but ahead of other unabated power plants as part of a flexible and low-carbon electricity system. We consider that the Facility and Reference Plant are likely to have similar levels of supply chain emissions.

The consultation on the DPA focussed on natural gas fuelled thermal power generation plants with carbon capture technology only. Business models developed for carbon capture technology deployed on alternative thermal power generation plants, including Biomass, are not within the scope of this consultation.

Question 6: Do you consider risk is appropriately allocated to enable investment in Projects and value for money for consumers? If not, please indicate the aspects of the contract where you believe risk is not appropriately allocated and why.

Summary of responses:

Four respondents felt that risks are appropriately allocated under the DPA. A number of areas where these respondents and others felt there were areas of concern are shown below;

Three respondents considered that the risk allocation is not appropriately allocated and there is a need for additional downside risk protection for equity shareholders, to mirror the gain share proposal for consumers.

A small number of respondents raised that the Force Majeure provisions do not provide relief where the event is not beyond the reasonable control of the Generator or its “Representatives”, where “Representatives” includes “Contractors”. Respondents raised concerns that as the T&S Network Operator is not excluded in the definition of “Contractors”, it could create a risk of the Generator being held liable for issues arising from T&S network availability, which is the responsibility of the T&S Operator, or could lead to scenarios where the T&S Operator’s actions (or lack of) prevent the Generator from benefitting from relief under the Force Majeure provisions. One respondent further suggested that the Gas Licensed Transporter should also be excluded from the definition of "Contractor".

A respondent queried the rationale for the Termination for Prolonged Force Majeure provision and the lack of compensation payable to the Generator in such a circumstance.

Two respondents considered that the Pre-Start Date and Generator Default termination rights are generally very severe and provide no opportunity for the generator to remedy. They also noted there currently are no rights to appeal the termination. They point to the Capacity Market arrangements and consider that their risk would be considered lower by projects if there was an appeal process included.

One respondent noted that unabated operation (as a result of T&S unavailability/constraint through planning and environmental permitting) is still not confirmed.

One respondent noted that the performance requirements, testing regime, and termination events under the DPA do not reflect the FOAK nature of these projects, and suggest the Government add a level of flexibility.

One respondent proposed that regarding the Target Commissioning Window (TCW) a more general provision to cover unforeseen issues that are revealed during the due diligence phase should be included to allow for extensions to the TCW, similarly to the provisions for Force Majeure, electricity/gas network connection delays and T&S commissioning delays.

One respondent noted that the Initial Conditions Precedent precluded Projects from progressing to DPA agreement without Applicable Planning Consent challenge periods being expired which departs from the CfD AR3 ICP standard terms where projects may proceed to contract agreement without all applicable planning consent challenge periods exhausted, but at their own risk. A further point was raised regarding the definition of “all associated infrastructure” which is not a defined term, this is used at Annex 1, Part A, Condition 4.E.

Two respondents provided feedback on the Change in Law and Qualifying Change in Law provisions in the DPA, specifically highlighting compensation payable following a change in law specifically excludes financing costs other than break costs.

One respondent considered that there might not be sufficient assurance that the risks of liability related to CO_2 leakage or damage to the T&S Network are appropriately allocated in the DPA, or in other elements of CCUS policy, as there is no provision confirming that the T&S Operator (or a Government entity) will take risk and/or title to CO_2 at the Delivery Point. The respondent further suggested that the Agreement Date representation on CO_2 capture in the Contract should be removed, explaining that where the Generator is unable to make this representation (e.g. because the T&S Operator has indicated to it that permanent storage is not possible, or, after connecting to the T&S Network, permanent storage is no longer possible), the Start Date cannot be achieved (and payments cannot commence). The respondent viewed it to be unreasonable for the Generator’s DPA payment to be limited due to an issue with the T&S Network that is out of the Generator’s control.

One respondent proposed increasing the allowed Net Dependable Capacity Adjustment limit of 10% which must be provided by the Milestone Delivery Date to take account of uncertainties with commissioning capture plant assets and give greater confidence to early Generators.

One respondent noted that the DPA Counterparty can launch an index review if the index is no longer available on commercially reasonable terms while the right is not given to the Generator. Further, a GRP Principles Review Request can only be instigated if 30% of generators make a request to the DPA Counterparty.

One respondent sought confirmation as to how the funding of the DPA Counterparty is segregated between the different subsidy schemes it administers to ensure there is sufficient protection regarding its ability to make payments under the DPA.

Government response

The gainshare mechanism and in particular the downside risk protection has been covered in our response to Q10 and would refer readers to this section where we have specifically covered this point.

Government recognises concerns raised by respondents relating to the definition of “Contractors”, and the T&S Operator and Gas Licensed Transporter have now been excluded from the definition. The revised definition can be found in Part 1 Definitions and Interpretation in the DPA Conditions.

The rationale for termination in the event of Prolonged Force Majeure was set out on page 15 of the October 2021 DPA Business Model update. This provision takes account of the significant capital expenditure that would be incurred by project developers to complete commissioning therefore the window in which the Prolonged Force Majeure event can apply to was shortened to that period before significant capital expenditure would be spent, e.g. up to the Milestone Satisfaction Date only. After the Milestone Satisfaction date, Condition 51 'Relief due to Force Majeure' of the DPA specifies the circumstances and requirements for claiming extensions to the Milestone Delivery Date for Force Majeure and in the event of Force Majeure occurring after the Milestone Delivery Date, extensions to the Longstop Date, and/or Target Commissioning Window.

The termination events for Pre-Start Date and Generator Default reflects the drafting used in the CfD AR4 terms and conditions. Pre-start Date Termination provisions ensure that DPA funding that has been committed to support the deployment of carbon capture infrastructure for power generation facilities is not tied up indefinitely in a project that has no realistic prospect of being commissioned. Generator Default termination is to ensure that the DPA Counterparty can terminate a contract if the Generator fails to fulfil its contractual requirements allowing government to reallocate monies which would have been required for that project to new projects. Default termination events associated with Non-Payment, Technical Compliance Termination Event and Minimum CO_2 Capture Rate include opportunities for cure prior to a Default termination taking effect. Where a Termination Event has occurred and is continuing the DPA Counterparty has the right, but not the obligation, to issue a Default Termination Notice to a Generator. We have provided responses to feedback on non-default termination provisions in Question 7.

In response to unabated operation and environmental permitting please see the response set out in in Question 4.

The performance requirements, testing regime and termination events resulting from these have been covered in the government response to Question 8 feedback.

In response to the feedback around the TCW and allowing for extensions to this for unforeseen issues. Government's view is that this has been developed to allow for these unforeseen events already and this is why a 12-month window has been proposed. This allows for issues to be managed without eroding the contract term. This has been widely used within the CfD framework and accepted as a sensible period which strikes the balance between delivering the project and mitigating from unforeseen issues. A provision for electricity/gas network connection delays and T&S commissioning delays has already been included which further protects a DPA contracted generator from those issues outside their direct control. We have provided further feedback regarding the TCW in our Question 8 response.

The QCiL provisions in the DPA have been covered in our response to Q4 above. In summary the QCiL provisions in the DPA have been designed to protect the Generator from changes in law and broadly mirror those in the renewable CfD which are considered investable and bankable.

Question 5 provides a detailed explanation regarding the responsibilities of both the T&S Operator and the Generator relating to the permanent storage of CO_2. As mentioned in

Question 5, the Network Code Indicative Heads of Terms does, in fact, state that the "title and risk in carbon dioxide delivered to the T&S Network at a Delivery Point in accordance with paragraph 1.1 shall pass to T&S Operator at that Delivery Point" (noting that the Heads of Terms are indicative only at this stage). Question 5 also outlines why the inclusion of the Agreement Date Representation on CO_2 Capture in the Contract is necessary and not considered an onerous requirement.

In response to the proposal to allow projects to progress to contract agreement without all necessary planning consent challenge periods outstanding, we note that we set out the eligibility criteria for Power Projects in section 3 of the Cluster Sequencing phase 2 guidance. At section 3.2 it specifies the requirement for prospective projects to have in place applicable planning consents in place by 2024 or by the point of DPA Agreement Date. This reflects the FOAK nature of CCUS facilities and the interconnected nature of Projects and the T&S Networks. Ensuring projects have applicable planning consents in place before entry into a DPA is prudent to ensure that cluster integration checks can be completed with confidence that selected projects necessary for the viability of the initial network design can legally progress.

We have used the term "all associated infrastructure" as, given the different technologies and configurations (retrofit vs new build), government is keen to ensure flexibility. Projects will provide a detailed description of its Facility which will be specified in Annex 1 of the Front End Agreement. The determination of Capture Assets and Generation Assets, which combined define the Facility are also set out in the definitions section of the Front End Agreement.

Our rationale for Permitted Reductions to Net Dependable Capacity Estimates of up to 10% prior to the Milestone Delivery Date was set out in the October 2021 DPA Business Model Update. This was to reflect industry concern regarding design uncertainty with FOAK projects whilst striking a balance between providing certainty that sufficient low carbon capacity will be delivered. We consider that the Permitted Reduction provisions and up to a total of two year OCP and LSD commissioning period, enables sufficient flexibility and time for plant optimisation to achieve minimum design standards to satisfy the OCP and LSD thresholds.

The DPA Counterparty is obligated under Condition 12.1(B) to produce and issue the Billing Statements and must therefore carry out the necessary settlement calculations. This will require the DPA Counterparty to access market data from the relevant price sources so that it may first calculate the Reference Prices. Generators do not have such an obligation.

The drafting is designed to mitigate the DPA Counterparty being compelled to use energy consumers money to acquire market data at any cost, and not to disadvantage Generators who we recognise may wish to access this data independently for their own internal audit purposes.

It is also important to consider the fact that if one Generator in a portfolio could not access the market data at commercially reasonable terms, that should not be allowed to jeopardise the DPA Counterparty's ability to calculate the Reference Prices for the DPA portfolio.

The 30% GRP Principles Request Criterion is designed to prevent unreasonable and repeated triggering of the GRP Principles Review procedures by a minority of Generators. It will not prevent the DPA Counterparty electing to undertake a GRP Principles Review under Condition 1.1(B), Part B, Annex 6, whenever it determines the Gas Reference Price is not reflective of gas market prices.

The DPA Counterparty is responsible for establishing a Gas Reference Price that conforms to the GRP Principles. Chiefly amongst these principles are that 1) the Gas Reference Price shall be the same for all CCUS Programme DPAs, and that 2) the Gas Reference Price shall reflect the market price for the sale of gas within Great Britain.

We set out in the October 2021 DPA Business Model update that we intend that the costs of the DPA shall be recovered from consumers. That is, we consider the DPA to be a form of Contract for Difference) and intend to direct the LCCC as CfD Counterparty to enter into any relevant DPA pursuant to section 10 Energy Act 2013. The Contracts for Difference (Electricity Supplier Obligations) Regulations 2014[17] (as amended), sets out the circumstances in which electricity suppliers shall make payments to the CfD Counterparty for the purposes of enabling the counterparty to make payments under a CfD. Government is considering what amendments might be required to those regulations in order to support the DPA payment model.

Question 7: Power CCUS projects will be part of a wider CCUS network. A T&S Prolonged Unavailability Event would have a significant impact on any project connected to the network, including those projects holding DPA Contracts. We need to consider how to best manage this interface risk. We have set out an initial minded to position on the termination right where there is a T&S Prolonged Unavailability Event, which seeks to balance the risk held by investors in the power CCUS project and investors in transport and storage and the wider network. Do you consider that there is a fair allocation of risk between the different interests in relation to Termination for T&S Prolonged Unavailability Events? If not, please provide your rationale.

Summary of responses:

Several respondents suggested that financing costs should be included in the compensation mechanism for this termination right. Some respondents also disagreed with the deduction of the Residual Value Adjustment or savings resulting from a Termination for Prolonged T&S Unavailability from the overall compensation.

Several respondents also requested that the compensation be sized to fully compensate all Generator debt and financing costs. Some respondents also queried whether construction costs could arise ‘directly’ from such a Termination for Prolonged T&S Unavailability and requested that the wording was clarified to ensure that historically incurred costs could be compensated. One respondent asked for clarification that Generators would not be forced to continue running unabated if it was not economically viable, and for examples of what the T&S Termination Savings might cover.

Multiple respondents noted that it should not be assumed that Generators would operate unabated. One respondent indicated that there should be the option for Generators to initiate the termination process, and to dispute the notification of a T&S Prolonged Unavailability Event. They were concerned that the potential length of the termination process was too long with there being a potential risk of not being able to generate revenue for this period of time.

One response raised concerns that the set off right to the T&S Termination Payment was not specific enough and may lead to double recovery of payments due from the Generator to the

[17] The Contracts for Difference (Electricity Supplier Obligations) Regulations 2014

DPA Counterparty. One respondent requested that the Generator should be involved in the process by which amounts the DPA Counterparty is entitled to set-off against the T&S Prolonged Unavailability Termination payment are calculated, and for the post-payment adjustment element to be removed in order to provide certainty for Generators and avoid a lock-up period.

Many respondents also noted that significant partial outages were not included in the process for T&S Prolonged Unavailability Termination. One respondent perceived that this would be inappropriate as it would be difficult to define significant partial outages.

Most respondents expressed that it should not be the Generator's responsibility to update the DPA Counterparty on the recovery of the T&S Network, which has been interpreted by government as referring to the proposed response notice that the Generator must provide to the DPA Counterparty within 6 months of the T&S Prolonged Unavailability Event Notice being issued.

Similarly, many respondents felt that the development of an Alternate T&S Network Solution Plan should not be the responsibility of the Generator, either because early projects would have limited alternate stores to approach or because others would be better placed to develop proposals for alternative routes to storage. Some respondents indicated that it was a financial burden to develop or that there might not be an incentive for Generators to do this if compensation was not sized appropriately and felt the alternative of providing a No Alternative T&S Solution Reason was overly burdensome. Multiple respondents noted that it was not clear from the drafting whether additional costs of such a plan would be covered.

One respondent fed back that they consider there to be a risk associated with decisions made by the regulator.

One response raised concerns with the process for Termination for failing to meet the T&S Connection Confirmation CP in circumstances where delays connecting originate from the T&S Operator.

One respondent suggested that the variable payment should continue to be paid during full T&S Outages or plant economics might be affected. One respondent asked for T&S Connection Agreements to include provisions which ensure that the Generator only has to pay T&S charges after receiving DPA payments to prevent issues with liquidity. One respondent also fed back that they should not be required to take on increased payments due to the oversizing of the T&S Network.

One respondent asked for clarification on whether Generation Outage Relief Events might include circumstances where unavailability of the T&S Network prevented generation or Force Majeure events, and asked whether T&S curtailment may occur as a result of a change in law. Please see the government response to Question 1 where similar feedback was received.

A response also noted that relying on a Deemed CO_2 Capture Rate during a T&S Outage event may reduce the availability payment.

Another response highlighted that the testing regime may need to be adjusted for retrofit projects, particularly retrofit biomass projects[18].

One respondent commented that we should consider an appeals route.

Government response

Under the compensation calculations for a Termination for Prolonged T&S Unavailability we have proposed compensating cost items which we consider would allow a Generator to pay off their baseline debt obligations. We have not proposed compensation which is automatically sized to all Generator debt and financing costs at the time of termination as we have not included, and do not intend to include, any DPA Counterparty right to approve any project refinancing, which could lead to significantly higher gearing than contemplated at signature and which government would not be willing to compensate.

The Residual Value Adjustment has been included to recognise that in the event of a termination of this kind, resulting from significant issues with the relevant T&S Cluster, a Generator may be left with an asset which has substantial ongoing value, which has been facilitated by their receipt of a DPA. The intended outcome of the compensation calculation is that Generators are able to meet their debt obligations over the remaining DPA term, and it is Government's view that ongoing value generated by the remaining asset should also contribute towards this. Revenues and asset value beyond the end of the DPA term are not included in this calculation, and would be retained in full by the Generator.

If there is no projected value from ongoing operation of a Generator's facility (for example if the costs associated with electricity generation would outweigh projected revenues) then the RVA would be zero and the full value of the listed cost items would be compensated.

However, we recognise the bankability risk that respondents have flagged, namely that the current proposal gives no guarantee that debt obligations can be met given the Residual Value Adjustment is calculated by way of a forecasting exercise. Therefore, we agree that the Termination for Prolonged T&S Unavailability compensation calculations may need to be amended to ensure that baseline debt obligations are fully compensated up front at a minimum, regardless of any Residual Value Adjustment. We will consider potential contractual approaches to this further, including with input from the Phase 2 negotiations, noting that a full cost compensation with no consideration of ongoing Facility value could be excessively advantageous to the Generator.

T&S Termination Savings would encompass any savings made by the Generator as a result of the Termination for Prolonged T&S Unavailability, for example avoided out of pocket costs and insurance proceeds.

The principle of payment set off is also found in the AR4 CfD drafting. The DPA Counterparty can set off any or all amounts owing to it by the Generator against any T&S Termination Payment due to the Generator. In the case of the DPA this may include Reconciliation Amounts which are required to reflect revisions in AP or VP Net payable amounts for example.

In common with the AR4 CfD drafting, there is no Generator unilateral termination right before the Specified Expiry Date. This reflects the cross-chain nature of the CCUS cluster. The

[18] The Dispatchable Power Agreement is not currently intended to be applied to facilities which generate electricity using biomass. The department is seeking to develop a Power BECCS business model, and a consultation on this model launched on 11 August 2022.

drafting of the T&S Prolonged Unavailability process, set out below, is intended to provide opportunity to resolve a prolonged outage before T&S Prolonged Unavailability Termination Date is reached.

We understand that a prolonged T&S outage will have a significant impact on project revenues and intend the Termination for T&S Prolonged Unavailability process to reflect this while also taking into account the cross-chain nature of a CCUS cluster, and ensuring that the T&S Operator has a chance to resolve a prolonged outage, or the Generator has an opportunity to find another route to permanent storage. We consider 36 months to be the appropriate balance if a T&S Prolonged Unavailability Event occurs. If the Generator becomes aware that the T&S Prolonged Unavailability Event is expected to last for over 36 months, or a T&S Cessation Event has occurred, then the Alternative T&S Network Solution Plan process gives them the opportunity to explore alternate routes to permanently store their CO_2, and if no option is available to them then they can provide a notice to the DPA Counterparty setting out a No Alternative T&S Network Solution Reason, leading to an earlier right to terminate. In this scenario, a generator could receive the T&S Termination Payment sooner.

We set out in the draft DPA Conditions that we were considering whether the termination process should be updated to reflect significant partial outages, and received mixed feedback about this proposal. One stakeholder was concerned that we had not defined a significant partial outage, and questioned the appropriateness of applying this termination right if the facility was still capturing and sequestering emissions. Another stakeholder emphasised that if the T&S Network only had a very small amount of available capacity, the definition of a Full T&S Outage may not be satisfied and the process may not be commenced. Government acknowledges the challenge posed by this and is continuing to consider this position, including in light of discussions on the network codes and input from phase 2 negotiations.

We consider that providing a three month period for a Generator to connect to an available T&S Network following a T&S Commissioning Delay Event is reasonable. If it fails to connect in that time its Availability Payments could be suspended. This is because we consider a Generator should be ready to connect to the network, having satisfied its T&S Connection Works in order to claim relief (as well as all other outstanding Conditions Precedents with the exception of the connection confirmation CP). The requirement also provides an incentive for a Generator to ensure prompt connection to an available T&S Network in order to provide value for money to the consumer, given the subsidy support for the availability of low carbon generation.

A number of respondents fed back that they were concerned that the process for Termination for T&S Unavailability placed obligations on the Generator to procure information from the T&S Operator about the T&S outage and provide this to the DPA Counterparty, and that the DPA Counterparty has a discretion to suspend payments if the Generator does not meet these obligations. The department is developing the CCS Network Codes alongside industry. We are working to ensure both the DPA Counterparty and Generators alike have access to all of the necessary information needed from a T&S Operator for contract management and meeting contractual obligations alike. We consider that the obligations placed on the Generator to procure the relevant information throughout this process are necessary to ensure the management of prolonged T&S Unavailability Events and should be feasible.

The obligations throughout the process require the sharing of information which the Generator will receive from the T&S Operator as well as the Generator's intended next steps, whether this is to wait for the T&S to be brought back online, produce an Alternative T&S Network Solution Plan, or that the Generator has explored the available options and determined that it is not possible to produce such a plan. It is important that a Generator keeps the DPA Counterparty updated on its plans to enable the DPA Counterparty to consider the appropriateness of termination, the obligations are not designed to penalise the Generator in circumstances where the T&S Operator has not provided the necessary information.

We have carefully considered the Generator feedback that the development of an Alternative T&S Network Solution Plan should not be an obligation on the Generator in the contract, and the potential feasibility of such a plan in the near future.

The Alternative T&S Network Solution Plan is designed as a mechanism to allow, in the low-probability high-impact event that their existing T&S Network is unavailable for a prolonged period of time, Generators to seek out and engage with any existing CO_2 storage options available if this scenario were to arise. The plan is not intended to require Generator's to develop proposals for bringing forward new CO_2 stores and we recognise that this falls outside of the expertise of many potential Power CCUS operators. The process includes the option for the Generator to notify the DPA Counterparty that they are unable to provide an Alternative T&S Network Solution plan due to a specified 'No Alternative T&S Solution Reason', which is intended to include scenarios where there is not an available commercial store which is technically capable or willing to accept flows of CO_2 from the Generator. We consider that a Generator is best placed to explore any storage options that are available to them at the time as they will have a good understanding of the technical and commercial constraints their individual project faces, but anticipate they may wish to engage with government throughout this process.

An Alternative T&S Network Solution Plan will be assessed by the DPA Counterparty by considering the circumstances at the time, including overall decarbonisation strategy and the feasibility and costs (capex and opex) of the suggested alternative route to store. The Generator and the DPA Counterparty may agree a bespoke variation to the DPA to reflect the new arrangement which may include amendments to reflect the additional costs associated with such plan. If an Alternative T&S Network Solution Plan cannot be developed, or a plan cannot be agreed, then the DPA Counterparty may terminate the DPA for failure to remedy the T&S Prolonged Unavailability Event, and the Generator will be entitled to compensation as set out in the DPA.

There is a detailed Dispute Resolution Procedure set out in Part 10 of the DPA, which sets out the procedures for resolving disputes in difference circumstances, including an Expert Determination Procedure and arbitration by the LCIA. We do not consider that further appeals processes are necessary.

Development of the regulatory framework pertinent to the T&S Network is included in the T&S business model January 2022 update[19] and CCUS Network Code Indicative Heads of Terms.

[19] Transport and storage business model: January 2022 update

Question 8: We have proposed testing requirements specified in Annex 2 "Testing Requirements" of the draft DPA Contract to provide clarity on what is expected from Generators during the Performance Tests detailed in the DPA. We have sought to align these requirements with industry standards and expectations. Does the proposed Testing Requirements strike the right balance between robustly assessing the performance of a Facility and not being overly onerous on a Generator? If not, what amendments do you think are necessary to determine performance of the Facility against?

Summary of responses:

The proposed testing requirements attracted many comments and suggestions from respondents. Within the responses several clear themes were established along with a diverse range of technical points or specific suggestions. There was no objection from respondents to the inclusion of a performance testing specification in principle within the DPA.

Eleven respondents provided feedback regarding the perceived rigidity of the proposed testing requirements given the FOAK nature of the Facility and contract termination rights associated with failure to satisfy the required OCP and LSD Performance Test thresholds represented a heightened investment risk.

Eight respondents provided feedback in response to the proposed requirement to undertake an Annual Net Dependable Capacity demonstration test within a specified window between 01 June to 01 September each year. Respondents generally felt that this may incentivise out of merit order running in summer months with associated cost implications. Several respondents proposed mirroring the Satisfactory Performance Demonstration (SPD) approach used in the Capacity Market as an alternative to performing an Annual NDC Test.

No objection to the inclusion of a Target Commissioning Window (TCW) was received. Respondents queried the specifics of how and when the TCW would be determined along with proposals for flexibility in determining the length and scope for extensions to it. One respondent noted that the requirement for the TCW to end by 31/12/2027 may be onerous to accommodate in a scenario where the T&S Network only becomes available in late 2027.

Applicability of proposed testing standards and correction curves was a common theme picked up on by respondents with technical queries and limitations of existing available standards identified. A smaller number of respondents noted that the proposed testing requirements did not sufficiently differentiate, or may need to be different, for testing plant performance of retrofit Projects vs new build Projects. Some specific queries were raised with the technical requirements of the proposed testing regime such as applicability of Heat and Mass Balance Diagrams and alternative metering / measurement instrumentation.

Five respondents provided feedback regarding the proposed Start-up (Shutdown) performance tests of which four respondents queried the rationale for a hot and warm start requirement with one respondent noting that a hot start scenario was unrealistic of typical operating profile. Two respondents proposed removing the requirement to test start up (shutdown) performance altogether as market signals provide sufficient incentive to respond rapidly.

Two respondents noted that the proposed performance testing requirements may require venting of separated high concentration CO_2 for a prolonged period if no T&S network was available to export the captured CO_2 on to at the time the tests are undertaken. Concerns were raised around the safety of this and interaction with the Environmental Permitting Regulations.

Several respondents queried the format and content of data submissions required from Generators to the DPA Counterparty and requests to clarify what information will be required to be made available via a Plant's SCADA system.

A small number of respondents queried how plant Performance Testing would be conducted in parallel with the commissioning of a Transport and Storage network and challenges this could pose.

Some project specific concerns where noted, for example, challenges posed by commissioning a plant on contaminated land.

Government response:

A common theme from respondents was that the proposed performance testing requirements are too rigid given the FOAK nature of the Facility and that contract termination rights associated with failure to achieve the required OCP and LSD Performance Test thresholds represented a heightened investment risk. We intend to retain the testing requirements specified in Annex 2 of the DPA Conditions. This is because we consider there is sufficient flexibility provided by condition 2.1 of Annex 2, part A, for both new build and retrofit projects alike, to propose the procedure they intend to adopt to meet the Performance Tests, which must be submitted to the DPA Counterparty at least six months before undertaking the Performance Tests. Justification should be provided if alternative standards or methodologies to those referenced in part 1.1 of the annex are proposed to the DPA Counterparty to ensure that an equivalent level of performance demonstration is achieved.

Government considers that retaining the requirement for Performance Tests is important to ensure that facilities are commissioned in accordance with expected performance levels agreed in the DPA.

Several respondents to the proposed Annual NDC Test Window (01 June to 01 September) identified that this may force out of merit order running in summer months when load factors are typically low thus causing increased operating costs and greater use of correction curves to adjust performance to reference conditions. We consider this feedback to be reasonable and as such will not specify in the standard terms of the contract the window in which testing must be performed. The Generator and DPA Counterparty shall agree during the negotiation phase of the DPA the window within which a Generator must undertake its Annual NDC test each operational year. This window will precede the Annual Adjusted NDC Implementation Date that will be specified in the Front End Agreement. This provides a Generator with the flexibility to determine when it is most economically efficient for it to undertake any planned maintenance periods prior to conducting the NDC test.

A number of respondents suggested an alternative test procedure to the full load test proposed for demonstrating Annual NDC performance. The alternative procedure proposed was to emulate the Satisfactory Performance Day (SPD) requirements of the Capacity Market whereby participants must demonstrate that it achieved generating capacity, at a level equal to its Capacity Market obligation, at least once over a 30-minute settlement period on three separate days in a delivery year. We do not consider that this is a sufficiently robust test to ensure that the amount of low carbon generating capacity that can be relied on to be available to the grid is provided and upon which the DPA availability payments are predicated. The purpose of the NDC testing requirement is to incentivise an ongoing high level of available low carbon generating capacity throughout the operating period ensuring linkage between the Availability Payment and verifiable level of Net Dependable Capacity on a forward-looking annual basis. It also ensures consistency of assessment and provides a standardised audit trail which, given the commitment of subsidy payment, is reasonable to require in order to ensure a robust assessment of plant performance thereby safeguarding value for money for consumers.

We set out the requirements for eligible Power Projects in section 3 of the Cluster Sequencing Guidance[20]. Namely, projects must be able to be operational no later than December 2027. We defined that Commercial Operation Date (COD) as the date that the plant is confirmed to have met the Operational Conditions Precedent (OCP) and the Project begins operating and exporting captured CO_2. However, we recognise that the Target Commissioning Window must be aligned with the T&S Cluster plans and will reference this to support alignment of the two.

Four respondents fed back that the rationale for the proposed warm and hot start Performance Test requirements was unclear. Specifically, two points were raised. Firstly, that the thresholds for OCP start up time performance test threshold of 125% of start-up time estimate and capture rate during the performance test was arbitrary. Secondly, the rationale for testing warm and hot start up times was unclear, and regarding the hot start up test, un-representative of typical operations where dual starts within a day are unlikely.

In response to the feedback that Start up (shutdown) time performance thresholds are arbitrary; the rationale for a 125% threshold is holding projects to the start-up time estimates provided and agreed in the DPA with an additional 25% headroom in place to allow for under-performance / uncertainty during the performance test. We consider this is a reasonable requirement ensuring value for money to the consumer and that projects are capable of delivering flexible and dispatchable power utilising best in class technology. It should also be noted that the Start Up (Shutdown) Test requirement is only required as part of the commissioning (OCP / LSD Performance Test requirements) therefore it is not overly onerous on the Generator to perform. Moreover, there is no limit to how many times a Generator may perform the performance demonstration within the OCP / LSD commissioning period (two years) to achieve the commissioning milestones providing sufficient time for optimisation of equipment if underperformance against design estimates manifests.

In regards to the second point, warm and hot start up time tests being unrepresentative of typical operating profiles for gas fired power plant, the rationale for requiring warm and hot start up times tests is to ensure that appropriate plant, capable of performing in a flexible and dispatchable role and able to react swiftly to market signals, were brought forward for assessment whilst discouraging any speculative applications. Whilst it maybe that a dual start within a day is presently unlikely, this may not reflect dispatch patterns longer term where increasing generation from renewable sources is foreseen.

We recognise that in circumstances where access to the T&S Network is unavailable or curtailed and Performance Testing is required operators will be required to vent captured CO_2 to atmosphere for the purposes of testing. Condition 8 of Annex 2 has been drafted to take account of potential T&S commissioning delay mismatch or outage event affecting the ability of projects to undertake a test run.

[20] Cluster sequencing for carbon Capture, usage, and storage (CCUS) deployment: Phase-2 guidance.

It is our expectation that Generators will design their plants and manage any such testing to ensure that it takes place safely and in accordance with any required permits that it has obtained.

Applicability of standards – we recognise that referenced performance test standards are in development and do not yet fully account for Power CCUS facilities in their entirety, e.g. ASME PTC 46 focussed on power plant, ASME PTC 48 not yet published, ISO 27919 focussed on capture plant. Hence, we have drafted provisions to allow flexibility of approach to testing methodology adopted. Please also refer to previous comments above on rigidity of testing requirements.

Data Submissions - We have provided a definition in Annex 2 of the "Test Report Minimum Technical Requirements" which lists what information is foreseeably required by the DPA Counterparty to assess the veracity of any submitted Test Report. It should also be noted that the Performance Test Procedure, to be agreed with the DPA Counterparty six months in advance of undertaking a performance test will provide an opportunity to agree format of acceptable data submissions. Furthermore, as with the renewable CfD scheme, it is anticipated that the DPA Counterparty will issue commissioning guidance to Generators on the forms of evidence that it will consider acceptable to demonstrate satisfaction of Performance Tests.

SCADA System requirements - The ability of the DPA Counterparty to be able to verify submitted data against plant performance is critical to ensure the integrity of the contract ensuring value for money for the consumer. We have clarified the information needed by the DPA Counterparty from the SCADA system includes plant dispatch information, fuel gas consumption and composition information, CO_2 export information and data relevant to the status of the capture plant operation (e.g. stored solvent regeneration).

Contaminated land and commissioning - We consider that the complexities of commissioning a plant posed by its location is a risk best placed by the Project developer as they are best placed to understand site specific challenges and how these are accounted for in determining the Target Commissioning Date and Target Commissioning Window. As previously set out, we have designed the testing requirements to be flexible with scope for Generators to tailor their proposed testing approach accordingly.

Steady state definition - The Full Load test must be conducted in accordance with the specified Test Performance Standards (see condition 3.3). The definition of Test Performance Standard has been defined in a way which is deliberately flexible in light of the fact that there are not yet finalised and established test standards for power CCUS projects. The appropriate standards in each case will depend on the proposed Test Procedure.

Priority T&S access for performance testing - The DPA is a contract between the DPA Counterparty and the Generator only. Any agreements for access to a T&S Network shall be between a Generator and the respective T&S Operator operating the T&S Network.

Question 9: Do you consider the proposal to enable the publication of certain contractual information by the DPA Counterparty to be proportionate and reasonable in light of our policy objective? If not, please provide your reasoning and which elements should be published in the alternative.

Summary of responses:

We had eleven responses to this question, ten of which agreed it is reasonable to publish certain information. In summary they felt that further consideration should be given as to what is appropriate to release and what must remain confidential, with particularly consideration needed to be given to the financial and economic figures before publication. One respondent asked to see a list of information that would be disclosed before they could respond to the question directly.

Several responses noted that the Availability Payment Rate and Variability Payment Rate will be based on technical characteristics, operating costs, and market assumptions, and are therefore commercially sensitive. To maintain transparency, they suggested that an anonymised periodic summary, for example quarterly, could be provided.

One respondent noted in order to better enable Generators to demonstrate that the integrity of their investment in FOAK technology, as well as the intellectual property of OEMs and other contractors, to both foster trusting relationships and promote competition, this regime should provide greater assurance as to how the DPA Counterparty will facilitate the protection of commercially-sensitive information.

Regarding the Supply Chain Reporting Requirement, a respondent suggested that government could consider allowing sensitive information to be supplied in an annex to indicate that this information is commercially sensitive to the Generator. The respondent also noted that the Supply Chain Report Fees (that shall be payable by the Generator in respect of the Generator's failure to provide the DPA Counterparty with the relevant Supply Chain Report) are not scaled to the size of the DPA Generator, or Project. It was suggested that this could be unfair for smaller Projects.

Government response:

Government considers that sharing of certain contractual information is a key enabler to meeting the overall policy objective and so it is reassuring to see that responses to this question were supportive. We remain committed to sharing information to help develop this sector but will further consider ways to ensure this is achieved whist all parties equally remain protected.

In the DPA April 2022 Business Model Update, we committed to providing guidance and a template for the Supply Chain Report, which needs to be completed at each of the reporting milestones. The terms of this requirement have been updated in the DPA Conditions and the report template can now be found at Annex 9 in the DPA Conditions ("Form of Supply Chain Report: Part A") and on gov.uk ("Form of Supply Chain Report: Part B")[21]. Part A of the report template contains a "Disclosure of Information" section which outlines that the Secretary of State may look to publish extracts from these reports in order to share information with wider industry, to support implementation of a CCUS supply chain, and to support the development

[21] Dispatchable Power Agreement: Form of Supply Chain Report Part B (Spreadsheet): November 2022

of the CCUS Programme in accordance with the disclosure permitted in 54.3(L). The Secretary of State may also be required to disclose any information that it holds, including such information that has been provided to it by the DPA Counterparty pursuant to a Permitted Purpose, in accordance with the Secretary of State's legal obligations (including, for example, under the Freedom of Information Act 2000 (FOIA), the Data Protection Act 2018, UK General Data Protection Regulation (UK GDPR) and the Environmental Information Regulations 2004 (EIR). However, within this section of the report template, there is the opportunity for Generators to explain the reasons why they consider any specific information contained with a Supply Chain Report should not be disclosed, to help the Secretary of State deal with information requests.

Regarding the size of the Supply Chain Report Fees, government considers that it is important to ensure compliance with the Supply Chain Reporting requirement, to provide the DPA Counterparty and the Secretary of State with key economic, technical and commercial data around the supply chain and the value drivers that underpin it. The size of the Fees is considered to be nominal and proportionate to ensure compliance with this reporting requirement, therefore any further reductions are not necessary. In addition, the DPA sets out that any Supply Chain Fees that accrue prior to the Start Date shall not be due and payable by the Generator unless and until the Start Date has occurred (subject to conditions set out in the Contract). Overall, we do not consider this to be an onerous reporting requirement given that there are only three Supply Chain Report milestones over the course of the DPA and the requirements for compliance are set out clearly in the DPA Conditions (in Part 1 Definitions and Interpretation, and Condition 25) and in Part A of the report template (Annex 9).

Question 10: As outlined, do you agree that the inclusion of a gain share mechanism in the DPA Contract is a proportionate measure to mitigate the risk of overcompensation and to facilitate compliance with subsidy control principles? If you believe the inclusion of a gain share mechanism is a disproportionate measure to achieving our objectives, or could significantly inhibit investment in the DPA, please provide your rationale.

Summary of responses:

Four respondents stated that the gain share mechanism was not proportionate.

Six respondents did not oppose the gain share mechanism in principle, but noted that downside risks should also be shared. One additional respondent noted only that the gain share mechanism creates too much risk to investors and could lead to higher APRi bids.

One respondent had no objections to the gainshare mechanism, subject to an appropriate IRR threshold being set commensurate with commercial interest rates.

Generally, respondents who did not feel that the current gain share mechanism met the DPAs objectives, had the following comments:

- That the current allocation process for the first DPAs was sufficiently competitive to ensure value for money for consumers, and that potential concerns around subsidy control compliance should be addressed on a project-by-project basis rather than through a standard set of gain share terms.
- That while there were other examples of gain share mechanisms in other support models, these were not an appropriate comparison as they typically exposed recipients

to lower levels of market risk than the DPA. They noted that the higher level of commercial risk under the DPA should mean that Generators had access to all potential rewards associated with those risks. In particular it was noted that:
    - the standard CfD with a fixed strike price provides a much higher level of protection from market risk compared to the DPA support mechanisms, and thus a gain share mechanism was more appropriate for that form of business model.
    - traditional PFIs typically deliver tight margins with minimal market risk and where gains are only available from project refinancing. Where projects do take commercial risk, one respondent noted that they had seen such risk being excluded from gain share mechanisms.
    - in the nuclear sector, potential gains are typically achieved through management of construction and maintenance costs.
- A one-way gain share mechanism as currently proposed would increase risk to the Generator by restricting commercial upside, which would disincentivise investment resulting in increased APRi bids and higher costs to consumers.
- A number of respondents noted that a corresponding 'pain share' mechanism could mitigate concerns around the proposed gain share mechanism, and could result in better overall VfM for consumers by reducing Generator exposure to market risk.
    - Some respondents specifically proposed a cap and floor regime, in which a Generator would be loaned additional sums if cashflows fell below the level required to meet debt obligations, paying such sums back to the Counterparty when cashflows increased above the minimum level. It was noted that the cap and floor regime for interconnectors was viewed as a bankable mechanism, and that a similar mechanism could result in substantially reduced overall support payments from consumers across the DPA.
- Some respondents noted that the gain share mechanism would only apply to, and therefore penalise, the best DPA Generators and questioned whether the late introduction of the mechanism was conducive to the timely conclusion of negotiations and rollout of the technology.
- One respondent proposed that assessment of the Equity IRR report should be at the Counterparty's cost rather than the Generators.
- Some respondents noted that the required corporate structures in the gain share mechanism might not be appropriate for all sponsors and financing arrangements, and that there may be other forms of appropriate credit support other than those listed in the credit support requirements.
- Some respondents noted that while the project gain share mechanism was a reasonable inclusion (provided it was changed to a symmetrical, rather than one-way mechanism), the sale gain share mechanism was disproportionate and could limit the pool of potential investors and did not sufficiently account for the risks that investors were taking on FOAK Power CCUS projects. One respondent noted that they could not find any other examples of a sale gain share mechanism beyond that for Hinkley Point C, which they noted was a unique project with highly specific planning assumptions.

Government response:

While we recognise that respondents to this question were generally either opposed to the inclusion of any gain share mechanism or viewed it as disproportionate without the inclusion of a corresponding pain share provision, we intend to retain both the project and sale gain share mechanisms in the DPA. The financial terms of the first DPAs will be negotiated with reference to overall financial projections for the relevant projects. While we are confident that those negotiations will be conducted in good faith, using the best available data, in reality the length of the DPA (10-15 years) and the significant uncertainties around the future makeup of the UK's power supply and demand mean that financial projections of these kinds are subject to significant uncertainty. We accept that the risks around this uncertainty will sit with Generators and may then be priced into APRi bids – and this may be systematic across Generators, given no one party has better access to information about the future than any other. However, risk pricing as part of the APRi leaves potential upside solely to the Generator. The gain share mechanism is a recognition that there is therefore a risk of overcompensation resulting from uncertainties, and in our view reflects a proportionate and reasonable response to protect UK consumers. We also note, with respect to comments on the timing of the mechanisms development, that the government has consistently indicated the possibility or likelihood of the introduction of such a mechanism into the DPA. The mechanism has been developed at pace, alongside the full contract, with the intention of providing visibility as to its detailed terms well in advance of negotiations.

This position has been informed by precedent. The National Audit Office (NAO) made several clear recommendations in their 2014 report on the allocation of 8 early CfD under the Final Investment Decision enabling for Renewables (FIDeR) scheme. Similar to the DPA, these FIDeR contracts were ultimately allocated following bilateral negotiations with developers, ahead of the fully competitive Allocation Round 1. In their report, the NAO recommended both that the Department should maximise the opportunity for price competition under the CfD scheme (Paragraph 18) and that "the Department should include clauses in future Contracts to enable it to clawback excessive returns achieved by individual projects" (Paragraph 19). The two recommendations were clearly not exclusive, and while we consider that the first recommendation has been achieved via competition in the Phase 2 allocation process, we do not consider that this process fulfils the requirements of the second recommendation, and therefore we will continue to maintain the gain share mechanism as part of the DPA at this stage. While we recognise that a CfD provides a more stable overall revenue than the DPA through the use of a strike price, we consider that the NAO's recommendations are still applicable more broadly to the DPA (which is legally a form of CfD) and that government should follow them where possible.

With respect to comments that proposed either a corresponding pain share mechanism, or a 'cap and floor' approach, either approach could be construed as a form of minimum revenue guarantee, which would be inconsistent with the fiscal rules under which the DPA has been developed. In addition, we consider that such an approach could disincentivise the efficient operation of plants in receipt of a DPA and increases the risk of 'gaming' of a complex sharing system to push more risk and cost onto consumers. We consider that a sharing mechanism on gains only does not carry the same level of risk to the overall DPA design.

Overall, in line with NAO recommendations, we consider that a combination of price competition on the APRi (which we acknowledge may include some form of risk pricing relating to uncertainties around future market revenues) and a gain share mechanism to provide consumer protections in the event of overperformance (with an appropriate, negotiated equity IRR threshold) should ensure an appropriate allocation of market risk under the DPA.

While we acknowledge that a number of support mechanisms across other UK industries or projects include symmetric pain-and-gain share mechanisms, or allocate a lower share of market risk to the private sector counterparty, such mechanisms often specify a higher sharing factor of any gains or underperformance overall than the 30% share above a single threshold which we have put forward under the DPA. For example, under the Hinkley Point C mechanism an initial 30% share at the first equity IRR threshold is followed by a 60% share at the second threshold while in PPP/PFI contracts or OFTOs, sharing is typically on a 50/50 basis (or for certain waste PPP/PFI contracts, an Authority share of 30-50% of all additional 3rd party revenue above base case). So while the Generator takes a greater share of the market risk under the DPA, their share of any gains is higher than in these examples.

We do not consider that either gain share mechanism should impact debt financing for projects of this kind, as we would expect senior lenders to primarily consider downside risks rather than potential upside for equity investors, which is the basis of any sharing under this mechanism.

While we recognise that any gain share mechanism has the potential to reduce returns to equity/junior investors, we consider that a gain share mechanism which is applied at an appropriate and proportionate equity IRR threshold and with the 30% sharing factor proposed should not materially impact equity investors or the cost of capital. We will seek to discuss further with applicants what that threshold should be for the first DPAs.

We recognise that some respondents felt that the sale gain share mechanism was less proportionate than the project gain share mechanism. While we will retain both mechanisms in the final draft DPA, we will continue to consider the proportionality of the sale gain share mechanism specifically including taking into account the views of the shortlisted projects as part of the Phase 2 process.

Finally, we recognise that the proposals around required corporate structures may not work for all project applicants. We are willing to discuss these proposals further with projects provided that the integrity of the mechanism as a whole, and the clarity of accounting for the Generator's finances, including clarity on the recipients of any distributions in any joint venture, are clear. Similarly, we are willing to discuss other forms of credit support that may be available to projects, provided projects can demonstrate their sufficiency for the purposes of the gain share mechanism provisions.

Question 11: The proposed gain share schedule would provide for two types of gain share, 'Project gain share' and 'sale gain share', in each case where such profits exceed a certain defined threshold.

At what level of Equity Internal Rate of Return (Equity IRR) do you consider that gains should be shared under the gain share mechanism? Please provide context and evidence in your response.

Summary of responses:

Respondents to this question generally reiterated or referenced their answers to question 10 of the consultation. No respondents put forward a level of equity IRR at which sharing gains would be appropriate under the proposed mechanism.

Government response:

As per our response to Question 10 above, we consider that the level of equity IRR at which the gain share threshold is set is material to the effectiveness and the risk-sharing profile of the gain share mechanism as a whole and will further develop this, including through the Phase 2 negotiation process.

Question 12: At what level of Equity IRR for a power CCUS Project do you consider that the risk of overcompensation under the DPA is low enough that the gainshare mechanism outlined here should not be required in order to mitigate that risk? Please provide context and evidence in your response.

Summary of responses:

Respondents to this question generally reiterated or referenced their answers to question 10 of the consultation. No respondents proposed a level of equity IRR at which the risk of overcompensation under the DPA would be low enough that the gain share mechanism would not be necessary.

Government response:

As above, we consider that the level of equity IRR at which the gain share threshold is set is material to the effectiveness and the risk-sharing profile of the gain share mechanism as a whole. If projects can demonstrate an IRR and sufficiently robust and well-evidenced analytical backing for revenue projections which indicate a very low probability of overcompensation even in the event of overperformance above base case, we may consider with Generators the most appropriate application of the gain share mechanism.

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