Department for
Business, Energy
& Industrial Strategy

Enabling a High Renewable, Net Zero Electricity System: Call for Evidence

Government response

July 2021

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

Contents

Introduction 4
Responses received 6
Summary of responses 7
Maintaining growth in renewable deployment to meet net zero targets 7
Ensuring overall system costs are minimised for electricity consumers 11
Supporting and adapting to innovative technologies and business models 15
Conclusion & next steps 21

Introduction

Our Call for Evidence on Enabling a High Renewables, Net Zero Electricity System ran from 14 December 2020 to 8 March 2021. We sought views on how a wide range of policies related to the deployment of renewable technologies should adapt over the next decade, cementing the UK's pathway to net zero. These views will inform our approach to the long-term future of renewable support and the future design of the Contracts for Difference (CfD) scheme.

We concentrated on three key areas:

- **Maintaining growth in renewable deployment to meet net zero targets** – understanding more about how projects will derive revenue and the security of that revenue, the impacts of increasing amounts of low marginal cost generation and how these impacts will change over time.
- **Ensuring overall system costs are minimised for electricity consumers** – exploring how to minimise the whole system costs of renewable deployment, particularly looking at the balance between price stability and exposure to demand signals, as well as locational signals and the role of renewables in providing whole-system services.
- **Supporting and adapting to innovative technologies and business models** – learning more about the new types of projects coming forward, such as those using multiple technologies, extensions of old projects or international projects that work across national borders.

The UK's June 2019 commitment to achieve net zero carbon emissions by 2050 means all sectors of the economy will need to be decarbonised. Central to this will be cutting emissions from the power sector. This will likely mean high levels of renewable generation, supported by other low carbon technologies that provide power, or reduce demand including gas with carbon capture and storage (CCUS), nuclear and other flexibility such as storage.

Since publishing the Call for Evidence, we have seen further success for renewable electricity in the UK. In 2020, renewable electricity accounted for 42.9 per cent of total electricity generation, setting a new record and exceeding the generation from fossil fuels for the first time[1]. Wind generation in the UK has also set new records throughout the first half of 2021.

Very significantly, in April 2021, the Government announced it would set in law the world's most ambitious climate change target as part of Carbon Budget 6 (CB6). This will cut emissions by 78% by 2035 compared to 1990 levels and incorporate the UK's share of shipping and aviation emissions for the first time[2]. This will bring the UK more than three quarters of the way to achieving net zero. For the power sector, this likely means an almost fully decarbonised power system, and crucially, will need to be achieved in less than 15 years.

The CfD has been extremely successful in bringing forward renewable generation whilst also reducing the costs of technology. Since its inception under the Energy Market Reform, the CfD

[1] https://www.gov.uk/government/statistics/energy-trends-section-6-renewables
[2] https://www.gov.uk/government/news/uk-enshrines-new-target-in-law-to-slash-emissions-by-78-by-2035

has become established as a route to bring forward investment at scale in low-carbon technologies. As a price-stability mechanism, the CfD is likely to continue to evolve to reflect learnings and a changing operating environment rather than more fundamental changes in the near term, with a focus on maintaining investment certainty and stability to enable deployment of renewables at a scale consistent with a CB6 trajectory.

However, CB6 does mean the longer-term questions in this Call for Evidence require even more attention as our energy system and support mechanisms adapt to a new decarbonisation landscape. How renewable deployment adapts in the longer-term must be seen in the context of the wider electricity system. A whole systems approach is needed to effectively integrate high levels of renewables onto the system, providing a secure and stable system at least cost to the grid and consumers.

We have already started considering a systems approach and alongside this government response BEIS is publishing the Capacity Market Call for Evidence. This seeks views on improving assurance that capacity will deliver when required, and how to better align with decarbonisation of the power sector, such as enhancing participation of low carbon power. Considering the electricity system as a whole will ensure scheme evolution is fit for the next, and most ambitious, chapter of the UK’s decarbonisation journey.

Responses received

We would like to thank all stakeholders that responded to this Call for Evidence, with detailed and insightful views that have been well received by several teams across BEIS. In total we received 103 responses. The Call for Evidence was available on GOV.UK and responses were received via email and Citizen Space. A short extension was granted in light of the Covid-19 restrictions, meaning the Call for Evidence was open from 14 December 2020 to 8 March 2021. The Call for Evidence was also advertised through our CfD Bulletin mailing list, and BEIS held a stakeholder engagement event on 26 February for the Call for Evidence.

We received responses from a variety of stakeholders, broken down as follows:

- *Industry*: including developers, suppliers, generators, service providers, manufacturing and consultancy – 54 responses (52%)
- *Public sector organisations*: including devolved administrations, local authorities, and government agencies – 3 responses (3%)
- *Private citizens*: 5 responses (5%)
- *Delivery*: including network operators and government delivery partners – 3 responses (3%)
- *Finance*: including investment firms and organisations – 7 responses (7%)
- *Research*: including academia, thinktanks and research institutions – 12 responses (12%)
- *Public and commercial representation*: including trade associations, industry bodies, charities, advocacy groups and advice services – 19 responses (18%)

Summary of responses

The Call for Evidence was to inform our thinking and approach to the long-term future of renewable support and the future design of the CfD scheme. In this section, we have provided a summary of responses received through the Call for Evidence, giving an opportunity for stakeholders to view how others responded. This is part of an ongoing engagement with stakeholders, and further dialogue will be vital as we adapt to meet the decarbonisation challenges of Carbon Budget 6 and net zero. Further consultation will be undertaken on any future policy proposals.

Maintaining growth in renewable deployment to meet net zero targets

1. **How is the industry currently approaching developing renewables projects without CfDs? In what ways might non-CfD backed projects obtain revenue from wholesale and other markets, and secure investment?**

Three approaches were commonly mentioned by respondents as alternative routes to market outside of the CfD: corporate purchase power agreements (CPPAs), utility purchase power agreements and trading openly on the wholesale market. The majority of respondents noted the ‘merchant’ market/CPPAs for renewables is growing, but still limited in size. Reasons for this included a lack of corporate appetite for CPPAs, a lack of credit worthy offtakers, short-term contracts and lower revenue returns for renewable projects. Respondents noted that this results in higher costs for project financing given the lack of long-term revenue stability.

Similarly, respondents mostly considered that in its current form the wholesale market is not a sufficient route to market and results in similar project finance challenges given the price volatility and increasing occurrences of price cannibalisation. However, respondents felt the wholesale market should still be considered as an additional route for renewable deployment, and the Government should look to expand, incentivise and encourage such routes. Nonetheless, responses did note that past decisions to exclude onshore wind and solar from CfD auctions forced projects to find other routes to market.

Finally, responses commonly referenced the Capacity Market (or other balancing/ancillary services), storage, hydrogen, and demand side response as other potential routes to secure additional revenue streams. However, respondents noted that mechanisms like the Capacity Market have volatile prices and can be challenging to predict revenue so may have limited value in securing project finance, though in most cases respondents suggested barriers to entry should be removed as far as possible. For the other revenue streams mentioned, responses typically noted that these markets would first need expanding to reduce the risks to investment.

2. **What do you consider to be the effects of increased low-carbon deployment on future wholesale power prices and renewable capture prices?**

Respondents most commonly noted that increased levels of renewable deployment on the energy system would likely cause a decrease in wholesale electricity prices and an increase in price volatility. This was primarily attributed to the price cannibalisation effects of having a wholesale price based on short-run marginal costs, commonly set by the costs of gas-powered generation, and the very low/zero operational costs of renewable generation assets. Very low market prices can be seen in periods of high renewable generation as conventional power is pushed further down the merit order; with respondents also suggesting negative pricing would become an increasingly common feature.

Similarly, the inverse can be seen when demand for power is high, but renewable generation is low. Some respondents also suggested this would lead to increases in system/balancing costs as additional renewables capacity will create uncertainty and volatility in the wholesale market.

There were also some common themes for approaches that could be taken to effectively integrate high levels of renewable deployment onto the system to manage wholesale prices. This included flexibility such as utilising storage or hydrogen, the Capacity Market (particularly combining projects with storage (most notably long-duration storage)), additional interconnection and a diverse energy mix.

Respondents did note on several occasions that the decrease in wholesale prices will benefit consumers and industrial customers, while creating uncertainty in project revenue and investment.

3. **How viable will investment in new renewable projects based primarily on wholesale prices be in future? Could this investment case be supported if there was more extensive deployment of flexible assets such as storage?**

Most respondents felt there was not a viable route to market for renewable projects based principally on future wholesale market prices. Primarily, this was because the wholesale market is not deemed investable by investors due to future price risk, price volatility, the likelihood of more frequent occurrences of price cannibalisation, and the lack of mitigations to protect investors from these risks. Some respondents noted there are some opportunities for merchant deployment available to those willing to take on these risks but highlighted that both the pipeline of economically viable opportunities and the pool of capital seeking to invest in them is limited. Therefore, the majority of respondents considered that some form of long-term revenue certainty or government intervention is necessary.

Several respondents noted that the current CfD design exacerbates the issues of price volatility and price cannibalisation. This is because projects are insulated from market signals and this becomes a barrier to the deployment of renewable projects without government support. Responses to other questions in this Call for Evidence included similar messages, that as more renewable generation is procured through the CfD, the more challenging 'merchant' deployment becomes. Around half of respondents also stated the current market structure needed to change as it was not designed to accommodate intermittent or low marginal cost generation, and therefore does not provide suitable investment signals in renewable projects. Carbon pricing was also commonly noted by respondents as a method to provide these signals, but at present, felt the future trajectory was too uncertain to invest against.

Most respondents also provided views on whether extensive deployment of flexible assets would support the investment case for renewable projects. Most responses noted there needs to be a significant increase in flexible assets, and that such deployment would reduce the erosion of wholesale market prices and price volatility and could mitigate other risks such as curtailment. However, while the majority of respondents acknowledged the need for flexibility, most considered that this could only partially mitigate some of the risks of price cannibalisation and price volatility; and would not be enough to increase viability of merchant deployment. This was primarily due to price forecasts already accounting for significant increases in flexibility, however given the inherent risk that deployment of flexible technologies may fail to materialise, most therefore noted this cannot provide the basis for investment decisions.

4. **How much longer after the 2021 allocation round should the current CfD be used? Is a price based on a short-run marginal cost market the most effective basis for a long-term renewables contract?**

The majority of responses were positive about the CfD scheme continuing, whether in the short-term or longer-term, as it provides investment certainty and regulatory continuity. Most respondents recognised the crucial role the CfD has played in significantly reducing costs of investment (particularly offshore wind). However, respondents also indicated changes to the CfD should be undertaken to potentially improve the scheme.

Only a few respondents considered the CfD should end after Allocation Round 4 (AR4) or Allocation Round 5 (AR5). This was primarily due to the CfD having achieved its target of reducing technology costs and the insulation from wholesale prices was now causing detrimental impacts to the market. This included raising the costs of levies and charges, increased payments to landowners, not delivering UK content in the supply chain, increased system costs, lack of system integration, presenting barriers to innovation, disincentivising the exploration of other revenue streams and creating market distortions/price cannibalisation.

A common theme for potential changes to the CfD included a focus on the system integration of renewable energy, such as through developing or providing support to storage, flexibility, hydrogen, demand side response, grid reinforcement, balancing/ancillary services, other less mature technologies and small scale and community energy. Another common suggestion was to hold the CfD auctions on a more frequent basis (e.g. yearly), as some technologies (onshore wind and solar) can deploy faster than others and this could avoid the potential "stop-start" construction of projects.

There were fewer responses to the second half of this question, with most covering general suitability of basing wholesale prices on short-run marginal costs. Responses generally followed common themes expressed in other questions in this section, notably the potential need for wider market reform and a whole systems approach, the ineffectiveness of basing wholesale prices on short-run marginal costs in a high renewables/low operating cost system, and the inability of these prices to provide long-term investment signals for renewables and other low-carbon technologies.

5. **Are there any changes or alternatives to the wholesale market that might facilitate merchant deployment?**
6. **How can market participants be encouraged to provide contracts to secure low-cost investment in renewables?**

These questions included detailed and varied responses on how (and to what extent) markets should be reformed, as well as alternative mechanisms to support further merchant deployment.

For Question 5, one of the most common themes from responses was that wholesale electricity markets lack sufficient liquidity and do not have sufficient volumes of traded power for proper price discovery. Responses noted that the UK needs a liquid active power futures market to reduce the cost of trading to encourage new, non-generator players to participate.

Across both questions respondents included a wide range of different ideas regarding wholesale market arrangements and alternative mechanisms to support merchant deployment, including: government to underwrite wholesale market contracts/CPPAs, mandating large corporates to procure wind/solar through long-term PPAs, a decarbonisation obligation on energy suppliers, expansion of financial instruments or other financial markets (e.g. derivatives market), a floor price/revenue guarantee mechanism for the CfD, locational/nodal pricing, development of the Capacity Market to allow separate pots for renewables and storage, and sufficient carbon pricing.

Ensuring overall system costs are minimised for electricity consumers

7. **How could intermittent renewable generators change their operating or investment behaviour to respond to wholesale price signals?**

A range of different options were provided in responses. The most commonly highlighted was the potential to invest in storage, both short and long duration, to shift output (and therefore revenue streams) to times of higher prices. The next most common option included altering the location of sites, specifically to avoid a correlation of generation with similar technology types. However, responses did mention that siting decisions are taken a long time before the project is built, so would be difficult to alter quickly should incentives change.

Other approaches were also mentioned in responses, including: the production of hydrogen, installation of tracking solar panels (to capture more generation than regular solar panels), scheduling maintenance at times of lower wholesale value, and more efficient turning down of generation output.

Responses also included information on how renewables can already respond to price signals, including frequency response and turning generation output up or down. It was suggested that better visibility of data on what the system needs would allow operators and developers to optimise how their assets are run.

8. **What would be the impact on the cost of capital of introducing greater exposure to the market price for power?**

The majority of respondents considered that increasing exposure of renewable projects to market signals would add to the cost of financing renewable projects. Some of these respondents also pointed to the impact on the type of investor that would be attracted to renewable assets if exposure to market signals increased, citing a reduced ability to attract low-cost debt into projects.

Conversely, a small number of respondents considered that the costs of capital would not rise if exposure to market prices was more prominent, citing greater value from wholesale market revenues, or a removal of distortions to price formation, and therefore improving confidence in short-term wholesale markets.

9. **In your view which of the potential options for providing increased exposure to market signals offers the greatest benefit to the consumer? Are there any other options that we should be considering?**

This question included several potential options to increase exposure of renewable projects to market signals. While responses were varied, the most common option cited moving to a price floor mechanism, primarily because of the retained protection this would offer renewable projects against times of low wholesale prices, with many also noting the increased incentive to take advantage of periods with high prices. There was also support for moving to a revenue floor. This was seen as potentially offering greater protection for investors, while allowing generators to respond to the full range of market signals and prices available. For similar reasons, responses commonly noted support for a model paying renewable projects for deemed generation rather than physical output.

Outside of the potential options listed in this question, responses also noted the potential for wider market reform, possible decarbonisation obligations on suppliers and making prices relating to balancing actions more cost reflective and transparent to facilitate renewable generators to respond to them. Finally, multiple responses expressed that government should only introduce changes gradually and with industry consultation, giving stakeholders time to develop strategies to adapt and respond to any price signals.

10. **Should CfD generators be incentivised to account for flexibility and wider system impacts, and/or to provide balancing services to the system operator? How could this be achieved?**

Overall, more responses agreed that generators should account for flexibility and wider system impacts, but through additional incentives, not mandatory requirements. Some respondents noted that the focus should be on ensuring CfD generators can take part in balancing services, removing barriers and encouraging entry to existing markets. For example, some responses pointed to generators being paid for deemed generation would improve behaviour and encourage participation in balancing services.

The primary counterargument to incentivising flexibility within the CfD was that this should be done through improved general market design outside of this mechanism. The main concerns raised were: potential for double counting, risk of a more fragmented market, potential inefficiencies of incentivising flex at the individual plant level rather than at system-wide level, and whether it is appropriate for CfD generators to bear the costs.

11. **Should the CfD mechanism incentivise minimum grid stability requirements (in CfD plants) to minimise system costs and help ensure secure and stable operation? How could this be achieved and what are the barriers?**

Many responses noted that grid code changes would be a more effective method of bringing forward grid stability requirements rather than incentivising through the CfD. However, some responses considered that there could still be incentives above and beyond the minimum requirements from grid code that could be utilised. Some respondents also noted that the focus should be on ensuring that Electricity Systems Operator (ESO) markets encourage renewable generators to participate. For example, ESO Power Available innovation project is trying to give ESO better visibility of wind projects and facilitate their participation in balancing markets[3].

12. Do CfD projects receive the right incentives to locate in the optimum locations?

The majority of respondents noted the CfD does not provide location-based incentives directly, but interactions were noted with other regulatory measures that do provide these incentives. Views were mixed on the effectiveness of those regulatory measures and whether resulting changes to CfD arrangements should be explored. Optimum locations were considered to be those where there is high quality resource, low-cost generation, diversification of supply, and favourable planning and environmental factors.

The majority of respondents identified the locational nature of transmission charges as one of the key factors in incentivising a CfD project's location. Views were mixed on the appropriateness of the resulting charging signals. Some argued that it is essential for costs to be borne by those generation projects locating in areas which are driving those costs, as this would drive efficient network investment and minimise constraint spending. In contrast, other respondents considered that the existing approach to transmission charging acts as a significant barrier to investment in certain locations, and ultimately to achieving net zero. Furthermore, some respondents considered that existing transmission charging arrangements are outdated as they are largely based on sending signals to fossil fuel generators, rather than renewables, which often have less flexibility on where they can optimally site.

13. Are there actions which government should consider, outside of Ofgem's current electricity network charging reviews, to help incentivise efficient market behaviour regarding the location of renewable assets?

Responses included a diverse range of views on the actions government could consider. There was a particular interest from respondents in government taking an increased strategic role in aspects of energy development. Some of the actions and priorities noted by respondents included:

- A 'system architect' to help provide strategic oversight of grid network planning;
- Targeted anticipatory investment in network infrastructure;
- Long-term renewables contracts directly including locational signals;
- Shared infrastructure developments encouraged through the CfD;
- Addressing the volatility of transmission charges;
- Expanding Ofgem's remit to focus on enabling a zero-carbon transition based on renewable energy;

[3] https://www.nationalgrideso.com/news/power-available-unlocking-renewables-potential-help-balance-electricity-system

- Shortening and streamlining the planning process.

14. Should the CfD do more to enable the sustainable growth, cost reduction and competitivity of UK supply chains and how could this be achieved?

Overall, there were three key themes from responses. Firstly, that incentives or requirements for supply chain development should be more intrinsically linked to success in the CfD auction process. Responses commonly suggested that the CfD mechanism places too much emphasis on the cost of bids and fails to consider the relationship between CfDs and other components. Respondents noted that the CfD should take a more rounded assessment of the “value” of bids by putting a higher weighting on local content, supply chain commitments and environmental impacts, rather than a sole focus on ensuring the cheapest possible price. Other responses suggested incentivising CfD returns based on the level of UK content, while others proposed imposing specific requirements or strict enforcement on CfD bidders.

Secondly, responses commonly suggested increasing the forward visibility of future CfD auctions, including budget allocation and capacity caps for each technology pot, to give the supply chain greater confidence to make investment and scale-up decisions. Several respondents also noted moving to annual auctions would provide similar benefits to the supply chain and project pipeline in terms of investment and confidence.

Finally, several responses also noted the need for targeted government support to overcome challenges in the supply chain where UK content is potentially uncompetitive, however, responses were mixed as to whether the CfD, or a separate mechanism should be used to support this. Several responses also noted the need for enabling infrastructure such as ports to facilitate supply chain development, and the importance of convincing international suppliers to come to the UK.

Supporting and adapting to innovative technologies and business models

15. What are the benefits of renewable projects using multiple low carbon technologies or being co-located with low-carbon flexible assets? Should the CfD support these projects and why?

The majority of responses considered there was value in co-locating renewable projects with low-carbon flexible assets. The most frequently noted benefits included:

- Optimising the use of grid connections and infrastructure, which was also recognised as minimising environmental impacts and reducing grid balancing costs;
- Potential to provide additional system services, such as inertia;
- An additional route to market for flexible technologies, which could lead to greater levels of deployment;
- Potential to facilitate sector-coupling[4];
- Reducing development and capital costs and allowing developers to benefit from economies of scale, strengthening business models for flexibility technologies;
- Efficiency for developers leading to reduced costs for consumers.

However, many responses were more neutral in their view of co-location. These responses noted that barriers should be removed to enable developers to pursue, if desired, co-location between flexible technologies and CfD assets. However, many noted that it is not always advantageous to co-locate flexibility, in particular storage, with generation and will typically depend on a case-by-case basis. A common theme from these responses was that delivering greater flexibility is a wider system challenge that may be more effectively addressed through other mechanisms outside the CfD.

Finally, some responses held concerns on co-locating flexibility and generation technologies. This was primarily due to a lack of perceived synergy between the two technologies. Responses noted the CfD is focussed on capacity and renewable generation, whereas flexibility is better aligned with security of supply and therefore should be addressed separately, for example through the Capacity Market or Balancing Market. These responses also shared a common theme with others, that government should take a wider systems approach to incentivise low-carbon flexible assets.

16. What are the benefits of projects with assets in different locations, including projects paired with flexible assets? Should the CfD support these and why?

[4] Where one part of the energy system becomes linked to another e.g. using electricity to produce gasses that can be stored and burned as fuel for industry, heating or other processes.

Responses included a diverse range of views. A common benefit from those in favour of allowing projects in different locations to be awarded CfDs was the ability for small-scale generators to aggregate into a single, larger project through a virtual power plant (VPP). Overall, responses noted this could improve the economics of individual projects, increase competitive tension, allow for further economies of scale and lower strike prices. Additionally, some responses considered that different assets aggregated into a VPP could alter output and offer less intermittency to the grid, removing the need for extensive balancing products. Some respondents noted that aggregated projects bidding for support is occurring in some EU nations already. Finally, other responses considered this could provide community projects with a route to market.

However, there was a similar number of respondents who were not in favour of altering the CfD to incorporate multi-locational projects. These responses highlighted the existing ability of developers and asset owners to diversify their portfolios by acquiring or developing multiple projects with separate CfDs, with some noting incentives for aggregation could provide perverse outcomes. It was also noted that aggregation of larger projects could minimise competitive tension in CfD auctions, with some suggesting limiting the size of projects being aggregated. Responses also raised the complexity in designing a system for multi-locational projects, noting the need for cross-stakeholder agreement between National Grid, the Low Carbon Contracts Company (LCCC) and Elexon to collectively review rules and principles on grid metering. Some considered assets of a VPP must be metered together virtually to be accounted against a single Balancing Mechanism Unit (BMU).

17. **What changes would government need to make to the Contract for Difference regime to facilitate the coordination of offshore energy infrastructure, what would be the benefits and costs of making them, and could there be a similar case for other renewable technologies?**

Responses included a variety of detailed proposals to alter the CfD to facilitate coordination of offshore energy infrastructure[5]. However, the majority of responses considered risks that could arise if multiple projects were to share a transmission asset. These risks included: one party in a shared project failing to secure a CfD or different parties getting CfDs at different times; a project not being able to bear their share of transmission costs until Final Investment Decision (FID) and certainty of a CfD; missing a CfD round due to grid development delays; missing CfD milestones due to construction delays and as a result missing on part of CfD payment; and disclosure of sensitive information to competitors.

[5] Several responses included considerations that do not fall within the scope of this Call for Evidence, but these have been noted by the relevant BEIS teams: technology to enable coordination (high voltage direct-current (HVDC), circuit breakers) and innovation support, speed of the Offshore Transmission Network Review (OTNR) to deliver integration, Offshore Transmission Owner (OFTO) rules discouraging/preventing benefits from storage, strategic investments linked to leasing outcomes, deploying electrolysers in conjunction with offshore wind assets, coordinated approach to planning & consenting, environmental concerns, international dialogue.

Responses proposed a variety of detailed proposals to address some of these issues, including:

- Allow joint bids and avoid projects competing against one another that share infrastructure;
- Allow flexibility in CfD milestones to recognise increased risk of delays/timing misalignment in projects sharing infrastructure;
- Change eligibility criteria to address risks from grid delays e.g. relaxation of the requirement to hold connection offer;
- Removing the need for competition through CfD regime and replacing it with a market-wide price floor.

Responses highlighted some of the potential costs of these solutions, including the risk of stranded assets and projects "sitting on CfDs" if coordinating parties win at different times, potentially higher strike prices if changes undermine the competitiveness of the bidding process and increased complexity of CfD contracts if they are to account for intricate interdependencies.

18. What changes would government need to make for the Contract for Difference to facilitate deployment of offshore wind as part of a hybrid offshore wind-interconnector project, and what would be the benefits and costs of making them?

Many respondents noted the general benefits of such hybrid projects. This included the ability to contribute to the Government's 40GW offshore wind and 18GW interconnection target by 2030 while utilising less infrastructure and reducing risk of curtailment. Responses highlighted the need for a holistic, coordinated approach for projects to be implemented outside the CfD and welcomed the progress of the Offshore Transmission Network Review (OTNR).

The majority of respondents were supportive of facilitating hybrid projects through the CfD as a method to de-risk investments. Respondents considered the CfD framework should be adapted to remove barriers to deployment through the scheme. However, responses also noted the need to avoid distorting auctions and a desire for a level playing field with other offshore wind projects, with offshore grid charging highlighted as a key issue.

There were mixed views on whether hybrid projects involving wind farms in Great Britain (GB) should be fully supported by a CfD, or whether the CfD should only support generation that was exported to GB. However, responses noted support schemes and wider policy should be aligned to avoid market distortion and ensure power flows are optimised correctly. Respondents were typically more negative about the potential for wind farms outside of GB to be supported by a CfD.

Responses included a diverse range of potential options to facilitate hybrid projects through the CfD, such as: separate metering for generation and interconnection, the potential for direct export to third countries and the possibility of using reference prices outside of GB, and modifications to the CfD process to account of the different delivery timescales interconnectors have compared to typical offshore transmission assets.

19. What role could international renewable projects play in our future generation mix in GB? Are there benefits to supporting these projects with government schemes and how could this be achieved?

Responses commonly indicated government should prioritise supporting GB based projects over international projects. Respondents considered there are enough potential GB projects to achieve the Government's decarbonisation objectives and would provide greater UK economic benefit in comparison to supporting international projects. Several responses noted that greater levels of interconnection would provide a more efficient approach to managing intermittent renewable output while offering the benefits of access to international markets – which is the Government's current strategy to support the balancing of the electricity system, through regional interconnectors providing the opportunity to import and export electricity.

However, some respondents did favour exploring the potential for international projects if they can be delivered at low cost to the consumer. Projects commonly referenced as potentially beneficial were offshore wind (fixed bottom and floating) located in the Irish, Celtic, and North Seas, while being paired with the island of Ireland and the continental mainland. Some developers of international projects also took the opportunity to set out the potential benefits of supporting international projects, including lower cost decarbonisation and greater system stability.

20. Should part-built project continue to be eligible to compete for CfDs after the fourth allocation round? Are we considering the right implications and what are your views on these?

The majority of responses were in favour of part-built projects continuing to be eligible to bid into the CfD. Common themes raised in these responses included:

- Promotes rapid deployment of assets as projects are typically "shovel ready", therefore accelerating the decarbonisation of the energy system and contributing to net zero;
- Would ensure projects are completed and not abandoned/paused halfway through;
- Could increase competitive tension and value for money for consumers as part-built projects may be cheaper than new build projects;
- Potentially encourage merchant deployment and new investors to the market who could use the CfD as a fall-back option, possibly reducing the cost of capital and investment risk. By not allowing part-built projects to compete in CfD, projects may avoid building on a merchant/part merchant basis.

However, a small number of respondents said part-built projects should not be eligible. This was primarily because these projects will typically have already made investment decisions and deemed to be commercially viable, while others noted concern that these projects may bid speculatively without signing a contract.

21. Can cost savings be achieved by developing extensions to existing projects, if so, how great are these cost savings, and what is the justification for these projects being supported through CfDs or any other government mechanism?

The majority of responses noted that cost savings could be achieved by developing extensions to existing projects, and highlighted several areas where this could be realised, including shared access, site assessment and operations (for example operation and maintenance (O&M) facilities), infrastructure, transmission costs, grid connections and construction logistics. Most considered this would benefit consumers, developers, and the system; but of particular benefit to offshore wind projects.

However, many respondents also noted overall cost savings for extension projects were limited, and in some cases overstated, with the magnitude of savings dependant on the type of project, which may not always be cheaper to deliver. Some respondents considered extension projects might offer some development expenditure savings, however, capital expenditure savings would largely remain level and projects would likely still require their transmission assets. Full planning processes, re-negotiation of the landholding/lease arrangements would also have to be conducted. Responses also referenced existing sites would continue to be exposed to high levels of uncertainty associated with grid charging arrangements, which is a large proportion of operational expenditure and a significant consideration for those located away from demand centres in the north of the UK.

Most responses supported eligibility of extension projects in the CfD scheme, with many noting there was good justification if projects were properly evaluated, and learnings incorporated. Most respondents considered extension projects to be essentially new projects, which still carried high upfront costs and investment risk. However, some responses did suggest support for extension projects through the CfD could be altered to ensure the deployment of new projects are not undercut, for example by having separate pots. Several respondents were also concerned that including extension projects in the CfD would entrench incumbent market participants rather than encourage new entrants who are essential to promote effective competition and innovation. Respondents also noted that government should not create specific market interventions encouraging extensions as this would only add cost to the system.

22. Similarly, can cost savings be achieved by repowering older projects, if so, how great are these cost savings, and what is the justification for these projects being supported through CfDs or any other government mechanism?

The majority of respondents noted some potential for cost savings for repowering projects. Responses highlighted areas where savings could be realised, including site identification and acquisition, grid connection, environment assessments, and re-use of existing site infrastructure. As with Q 21, respondents considered the magnitude of savings would differ depending on the type of repowering project. Several responses did note other benefits (outside of cost savings), including the pre-existing community engagement and that repowered projects are potentially more environmentally sustainable.

However, many respondents noted most costs would remain for repowering projects. For example, responses referenced how repowered sites would normally have higher site capacity requiring new export cables; how full repowering would typically require new, larger turbines to be installed; in some cases, a full site re-design would be required that could include the replacement of foundations, access tracks and crane-pads, as well as the cost of decommissioning the original asset; and new planning permission as repowered projects would effectively be a new project built on the site of an old one.

Most respondents supported CfDs (or other government mechanisms) being made available to repowered projects, however, some caveated this should only be for partial or fully repowered projects rather than life extension projects. A common reason was the significant upfront costs involved with repowering projects and that the revenue certainty provided through the CfD will remain critical to attract competitive financing rates. Respondents also noted how repowered projects could be incorporated into the CfD scheme. Several responses highlighted careful consideration of auction parameters and pot sizes with some suggesting the use of separate pots for repowered projects. Some responses also considered how allowing repowering projects to compete in the CfD would help maintain competition and lower costs for consumers into the 2030s when these projects will likely begin to appear.

Conclusion & next steps

The Government's June 2019 Net Zero announcement and the more recent announcement in April 2021 of Carbon Budget 6, firmly puts the UK on an ambitious decarbonisation trajectory. Vital to this will be ensuring the continued long-term success of renewable deployment and ensuring the wider electricity system is able to fully utilise the opportunities of high levels of renewable generation. The responses to this Call for Evidence have been insightful and well received by teams across BEIS, including Flexibility & Storage, Smart Systems, Network Infrastructure and Future Markets.

The Government's current renewable support mechanism, the CfD, has been hugely successful in delivering its objectives. It has brought forward low carbon generation at scale while reducing technology and consumer costs. The CfD has become established as a mechanism to drive decarbonisation. Given the immediate challenges of CB6, the need will likely remain to focus on unlocking the required investment in renewable generation at low cost to the consumer.

However, we are aware that challenges have emerged over time in procuring renewables through the CfD, such as the interactions with locational signals, flexibility, repowering, merchant deployment and innovations in renewable projects. The Call for Evidence responses have highlighted two aspects to this: the need for short-term incremental improvements and longer-term change. For the near-term, responses will inform the design of future allocation rounds from Allocation Round 5 – particularly how we strike the right balance between supporting investment in new projects, while exposing projects to the right market signals to drive efficient behaviour. Further consultation will be undertaken on any future proposed policy changes.

Longer-term, responses will inform the Government's view of its role in supporting renewable deployment, including the use of the CfD within broader market arrangements in the long-term. We recognise any longer-term changes will need to be considered holistically as part of a wider approach to the electricity market, ensuring we remain on track to deliver the deployment and energy system required for CB6 and net zero.

In this regard, the Government is also publishing alongside this response the Capacity Market Call for Evidence. This seeks views on potential actions to better align the Capacity Market's design with decarbonisation of the power sector, such as removing barriers for low-carbon technologies and potentially introducing a separate auction for low-carbon power, as well as how to improve assurance that capacity will deliver when required. The Government will also bring forward the Net Zero Strategy, to be published before COP26, that will set out the Government's vision for transitioning to a net zero economy[6].

Although the CfD and other government mechanisms will adapt to meet our new decarbonisation challenges, it is clear we will need to adopt a system-wide approach and

[6] https://www.gov.uk/government/news/uk-enshrines-new-target-in-law-to-slash-emissions-by-78-by-2035

consider electricity policies and markets in the round. BEIS is currently working with Ofgem and ESO to ensure we have the appropriate market mechanisms in place to deliver our decarbonisation targets securely and cost-effectively. Building on the evidence provided in this Call for Evidence, we will work closely with industry, academia, and wider stakeholders to further consider how our policies and markets should continue to evolve.

This consultation is available from: https://www.gov.uk/government/consultations/enabling-a-high-renewable-net-zero-electricity-system-call-for-evidence

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