Consultation: Further reforms to the Contracts for Difference scheme for Allocation Round 7

Response from UCL's Centre for Net Zero Market Design, within the Institute for Sustainable Resources

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The UCL Institute for Sustainable Resources' mission is to provide evidence, expertise and training to respond to climate change and support sustainable transitions for people and planet.

The UCL Centre for Net Zero Market Design works across academia, industry, government, regulatory bodies and other stakeholders, to provide expert advice on the best policies and practices for creating and maintaining effective electricity markets as we decarbonise power systems in the UK and beyond.

This is a summary of a response submitted via the online questionnaire on the UK government website. We have chosen to answer the questions where we have specific expertise.

We would be happy to discuss this response or any of our other work. Please contact Katrina.salmon.23@ucl.ac.uk.

Chapter 2.1 - Relaxing CfD eligibility criteria for fixed-bottom offshore wind projects

2. Do you support the general proposal to relax eligibility requirements to enable projects to apply for a CfD while awaiting their planning consent? Yes, No, Unsure? Please provide any further comments to support your answer.

Yes.

There are delivery risks from the projects that do not have planning consent. They are not at an appropriate stage to progress once they are granted a CfD award, and there are many reasons why planning might never be granted. However, under very strict circumstances (as outlined below), a relaxation of planning rules may speed up renewables rollout and reduce overall costs. A relaxation should only be considered for wind farms that have submitted planning applications but not received a decision yet. Planning would also have to be obtained within a short time frame, e.g., 3-6 months after CfD award and allow for the next best bidder to fill the spot, should planning not be granted. Strict definitions are needed, as otherwise projects in different development stages would compete against each other. This means that less-developed projects with fewer sunk costs would be more competitive in the auction rounds despite delivery risks. For future CfD rounds, DESNZ should seek ways to integrate planning approval into the CfD process, as is the case in many other countries.

8. Do you agree that the Non-Delivery Disincentive should apply to unconsented projects that fail to return a signed CfD contract by the statutory deadline? Yes, No, Unsure? Please provide any further evidence to support your answer.

Yes.

In fact, the non-delivery incentive could be increased to level out any competitive advantages that may arise from including less mature projects. This could be, e.g., a doubling of exclusion time for projects that fail to take up the CfD.

9. Do you agree that certain contractual obligations and milestones should be deferred or some flexibility permitted for unconsented projects until a planning decision is issued? Yes, No, Unsure? Please provide any further evidence to support your answer.

No.

The rule should only allow for achieving planning consent after the CfD auction (where this is the only hold-up).

10. Do you support the following flexibilities in the CfD contract to accommodate unconsented projects?:

a. Deferment of the Milestone Delivery Date until a planning condition is issued. Yes, No, Unsure?

No.

This would lead to option bidding in the absence of strong penalties, and disadvantage developers with sufficiently progressed projects.

b. Ability to leave contract early without penalty if planning consent is delayed beyond a certain date. Yes, No, Unsure?

Yes.

Built-in break clause after 3-6 months, then CfD award should be granted to the next best bidder with a consented project.

c. Provision to allow unconsented generators to adjust their contracts to accommodate planning conditions imposed on their projects following consent approval. Yes, No, Unsure?

No.

16. Are you in favour of the Secretary of State having the power to see anonymised bid stack information?

Yes.

This would be useful particularly "at the margin" of the bids, to avoid the kind of cliff-edge failure to secure a large windfarm for a very small additional cost, seen in AR6. On the assumption of sufficient auction liquidity (and hence, uncertainties around clearing price as well as other information), there would not seem to be a significant problem with risks of gaming, and the benefits probably outweigh any such risks.

Economically, many debates between "setting prices [or budgets] vs setting quantities", in practice given uncertainties, result in the conclusion that mechanisms should ensure a balance at the margin of these objectives. This seems another example of that principle.

However, it is not at all obvious that there would be any benefit in the SoS seeing the full bid stack, which could have other adverse incentives: the information transmitted should be confined to that necessary for achieving the specific objective.

17. Would the Secretary of State seeing anonymised OFW bid information have a negative impact on:

See answer to Q16

18. Do you believe this proposal could increase the likelihood of a preferable outcome for both industry and consumers?

Yes ... as well as, potentially, the environment (ie. future consumers)!

Chapter 2.3 - Increasing the contract term for future CfD projects

Market failure

22. Do you expect that new renewable electricity projects operating on a 15-year CfD will be exposed to greater market price risk than was originally conceived in the EMR (2013)? Yes or No? Please explain why, providing evidence where possible.

Yes.

With rising periods of surplus renewables and the negative price rule, it seems clear that new renewables will face greater revenue risk than CfDs initiated a decade ago. The question refers to “market price risk” - which may well also be higher, but we assume the question is more broadly about revenue risk, including volume risk, which rises with growing periods and extent of surplus. Our research published last year[1] indicates and supports NESO projections, in that:

- Without significantly increased system flexibility, inflexible sources of low carbon generation could produce ‘surplus power’ during around 50% of hours by 2030.
- The volume of potential surplus equates to around 27% of total wind generation in 2030, which can be used as a proxy for *average* levels of economic curtailment.
- However, no longer in receipt of support payments, generators in their merchant tail would theoretically be placed behind all RO or CfD-supported assets in the merit order, therefore would be subject to higher than average levels of economic curtailment. Our research showed that for the wind generator at the margin, levels of economic curtailment could reach as high as 75% of total potential output already by 2030. For new generators, the expectations for post-contract value could be correspondingly

higher. High levels of volume risk should be considered alongside price-risk to assess the total revenue risk for post-contract generation – but need to recognise the corollary, limiting the additional contribution that new investments would actually make (if they start to push significant existing generation off the system).

- During such periods of surplus, one would *additionally* expect either negative or very low (near-zero due to the negative pricing rule) prices in the wholesale market, exacerbating price risk for generators, both in contract (if negative prices) and in their merchant tail.

RECOGNISING THE IMPLICATIONS: HERDING AT ZERO WHOLESALE PRICE

20-year CfDs would be expected to reduce the cost of capital, and hence CfD strike prices, as flagged in our answers to Q24 and Q25. In addition, we consider it strategically important for DESNZ to consider several other issues including impact on wholesale market operation and the political narrative **(see =>Q32),** for which the following understanding is important.

In this response we consider 'standard CfD rules" as being those with a negative pricing rule, such that generators are paid the strike price for output sold, providing day-ahead reference price is not negative. This implies that as and when periods of potential surplus are likely, **all holders of such CfDs have a very strong incentive to ensure prices in the day-ahead market do not go negative. To maximise their chances of finding a buyer, they have an incentive to bid zero** price in the day-ahead market. As long as the day-ahead wholesale price does not go below zero, they will then get their strike price, paid by government through LCCC levies.

As yet, we are not convinced that anyone has a good understanding of what this would imply for the operation of the market and related incentives. In theory, those CfD holders could even pay other organisations a little to absorb and dump surplus power whenever the day-ahead price is zero.

There is also a powerful interaction with DESNZ's decision on a post-contract regime, currently proposed (for onshore wind) as a CfD.

NESO predicts there will be over 55GW of offshore wind and 70GW of solar by 2035). Already, NESO projects **by 2035** we would have over 40GW of offshore wind and 55GW of solar bidding at zero price whenever there is the prospect of surplus.[2] It could be larger; UCL Energy Institute's Green Light scenario had around 115GW of wind and 50GW of solar by 2035.[3] Wholesale prices could be close to zero for well over half the time. Storage generators, of course, would do well; knowing this, presumably they would offer to buy at zero price.

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[2] https://www.neso.energy/document/321041/download

[3] https://www.ucl.ac.uk/bartlett/energy/sites/bartlett_energy/files/greenlight_mbarrett_041023.pdf

If DESNZ adopts policies both to have 20-year CfDs, and to use CfDs to support repowering, the implication would seem to be that by 2050, almost the entire fleet of wind and solar **(between 210-260GW** according to NESO**)** would bid zero price (UCL Energy Institute's Green Light scenario has almost 200GW of wind and 100GW of solar by then). Research by other UCL colleagues suggests there will be surplus electricity in 33% of the year by 2050 with 155GW of wind and 155GW of solar.[4] The scenarios of course have large amounts of diverse flexibility, but storage, and other supplier flexibility providers, would be happy to buy at that price, potentially for most of the time – so hours of herding at zero price would potentially be much bigger.

The implications for the market are hard to discern, but if this is the broad picture, the implication for the structure of bills is that only a small part of the cost of generation would be reflected in dynamics of wholesale prices; most would be comprise LCCC payments to CfD generators, paying the difference between zero and the contract strike prices for most of UK generation, much of the time.

See also our answer to =>Q28 for a suggestion of one way to tackle this problem, which we emphasise, is speculative and would benefit from further consideration (and so unlikely a candidate for AR7).

23. In your view, do you have concerns about the economic viability of CfD assets once they have reached the end of their CfD term? Yes or No? Please explain why, providing evidence where possible.

Potentially YES. See above. We have not had access to specific data on costs of asset lifetime extension / repowering etc, but the current situation would imply:

- As above, rapidly rising periods of 'potential surplus' generation, with our research indicating there could be surplus power for 50% of the year already by 2030 without a significant increase in system flexibility. High levels of economic curtailment of output from renewables post-contract could be expected as they would likely place last in the merit order of inflexible low carbon generation. [5]
- Tens of GW of assets with an incentive to bid negative prices, particularly over the next decade, during said periods of potential surplus. Note, however, that this section's question is about extending the term of *new* CfD contracts; by the time new contracts have reached 15 years, all the assets with an incentive to bid negative will have come off contract (excepting Hinkley Point). The extent of negative bidding behaviour from generators in their merchant tail is then about the nature of any post-contract support.

[4] https://www.sciencedirect.com/science/article/pii/S0360544222023325

[5] https://www.ucl.ac.uk/bartlett/sustainable/sites/bartlett_sustainable/files/working_paper6_generating_surplus.pdf, https://discovery.ucl.ac.uk/id/eprint/10194430/1/UCL%20ISR%20REMA%202%20response%20updated.pdf

- A rising capacity of assets with a negative price rule, which would incentivise ‘herding behaviour’, bidding close to zero during periods of surplus, posing significant risk to the ability of post-contract renewables to accrue sufficient revenue to cover costs.

In practice, given construction periods, new CfDs from AR7 / AR8 would still be on contract well into the 2040s - the mid (for 15-year CfDs) or late (for 20 year CfDs) 2040s. Providing all new contracts have a negative price rule or equivalent, the issue would be the frequency of very low / zero prices, rather than negative prices *per se,* but the implications for overall revenue risk and therefore investor risk are similar.

Obviously, negative or close-to-zero wholesale prices would occur for only part of the time. It is impossible to predict exactly how frequently because it depends on the interaction of new and old CfDs, post-contract arrangements, the scale and operation of storage / other flexible demand response, and also whether or not there is zonal pricing (which would have opposite implications in different regions depending on regional generation/demand balance and structures).

It may well be that, post-contract, continued operation with some form of life-extension / ongoing maintenance would still be viable and profit from periods without surplus. This would depend critically on what drives wholesale prices in such periods, including the terms of gas operation.[6]

24. If yes to 22 and/or 23, where possible, please provide evidence quantifying the impact you believe this may have on CfD strike price bids (% and/or £/MWh).

In the following, we assume that the question refers to CfDs as currently designed, i.e. paid strike price for output sold to off-takers, providing day-ahead reference price is not negative. (which in this response we term ‘standard’ CfDs),

The implications for Deemed or Capacity CfDs could be rather different; for these, post-contract would represent a sharper financial cliff edge. For standard CfDs, revenue expectations might already be for revenues to decline over time even during the contract period, due to rising volume risk; the big post-contract change would be the price received for volume sold.

This impact of post-contract expectations on the strike price of new CfDs itself depends on many factors.

- The frequency of periods with surplus *vs* deficit of must-run / renewables generation, even assuming that frequency of actual *negative* wholesale prices will be negligible (see answer to #23).
- The extent of storage and other absorptive flexibility, in reducing the de-facto extent of close-to-zero wholesale prices; more storage would, however, correspondingly reduce

[6] If gas is in-market: the gas price, the carbon price, and whether gas pays the cost of any CCS or whether that is subsidised.

the frequency of very high wholesale prices. Estimating the revenue implications properly would thus require assumptions and modelling of storage, of various durations, more than 15 years ahead.

- Price expectations for periods insufficiently covered by renewables+storage would (interconnection aside) presumably depend on terms of gas operation as noted in the response to Q23; assuming that government subsidises most CCS operating in the 2040s, but the capacity is still moderate, expectations for wholesale prices in periods of renewables deficit might get much higher if gas is moved into a strategic reserve, with a (high) trigger price.
- The composition and terms of finance, in particular, the extent to which relevant finance discounts the value of revenues beyond 15 years, and also, critically, how this may be affected by uncertainty.

Potential benefits

25. Do you agree that increasing the contract term will reduce cost of capital? Yes or No? If yes, please state the breakdown of impacts on i) cost of debt, ii) cost of equity, and iii) gearing. If no, please explain why, providing evidence where possible.

Yes.

Longer contract will decrease the cost of capital. Revenue risks are reduced at the tail end of the contract. Even though uncertainty about the negative pricing rule, will mean lower revenues, the added certainty that at least some hours will be remunerated through the CfD scheme allows or financial predictability, and quite likely raises the P90 scenarios substantially, thus lower financing costs. Some industry data is available for this[7], which suggests that cost of equity could be reduced by 100 basis points, and debt-gearing increase by 3-4% percentage points.

26. If yes to 25, where possible, please provide evidence to quantify the impact you believe this may have on CfD strike price bids (% and/or £/MWh) via i) reduced cost of capital, ii) increased subsidy period, and iii) details of discount rates applied.

These cost of capital changes could lead to a not-insignificant reduction in LCOE. Based on the numbers in #25, LCOE could decrease by some 15% when going from a 15-year to a 20-year timeline. Numbers will vary for different wind farms, of course. The overall financing cost share of total LCOE cost could reduce by some 5%age points with the more favourable financing conditions. Given inevitable uncertainties, the ideal would be if DESNZ could devise a way to actually find out the scale of strike price reduction (and total contract cost impact) of the choice between 15- and 20-year CfDs. One option might be to require bidders to submit price schedules for both 15- and 20-year contracts, though it seems possibly they might then

[7] i.e. https://jeromeaparis.substack.com/p/tariff-design-and-lcoe

artificially elevate prices for 15-year contracts given the natural preference of bidders for 20 year contracts.

27. To what extent would a potential reduction in strike price from longer contracts be limited if there was insufficient competition in auctions? Please provide evidence where possible, specifically, detail on the justification for your assessment of the extent would be appreciated.

We cannot see why longer CfD contracts would lead to less competition, in fact, longer contracts should encourage more bidders to partake in the auction. However, if developers think they can predict the market well enough, through a lack of competition or otherwise, they will naturally seek to increase their rent. However, this is a general auction design question, not related to the contract length.

28. Are there any further changes to auction rules or design that the Government could make to increase the likelihood that project cost savings feed through to strike price bids, and so billpayers, and/or offset the limitations from insufficient competition?

We have alluded (Q23) to the apparent problem of large-scale herding, with 10s of GW bidding zero price in the wholesale market, which would not reduce consumer bills which are determined by the strike price (for as long as renewables remain on CfD contract). Since the implications of this are not clear, the impact on overall system costs and costs to consumers are also unclear. All future CfD allocations would, from the outset of operation, face the same uncertainty about how offtake would get allocated in periods of surplus renewables and bulk day-ahead bids at price 0. It is not obvious that PPAs, or bidding in forward markets, would necessarily solve the problem as it could still inject some price risk relative to the day-ahead reference price.

Since we expect substantial periods of surplus generation already by 2030, those risks are already present for new generation. But, each successive CfD round would face increased risks and uncertainties about actual offtake and/or price, right from the start of operation: they would be competing on equal terms with the accumulated generation from past contracts. **Investment in all CfDs might thus have to incorporate some element of offtake/price risk, from the outset, *with uncertainties growing over time, including through any contract extension.***

In our paper ‘Generating Surplus’ we concluded that the *underlying* problem can only be resolved through increasing storage or other absorptive capacity, making economic use of surplus; for investors, it remains unclear the extent to which this may help, especially in the early years of contracts.

One speculative idea, for consideration in future AR rounds, could be for what might be termed a **‘ramped CfD’.** The rule that generators would not receive their strike price when the day-ahead wholesale price is *zero* is, after all, a more-or-less arbitrary threshold. It could be possible to say that the threshold would rise during the contract period: starting with zero, and for example rising by £1/MWh each year. After 15 years, the generators would only receive their strike price if the day-ahead market is above £15/MWh – still very low, ensuring they are prioritised before gas, etc; the rule would only be relevant in times of surplus renewables generation. But it would, in effect, establish a 'contract merit order' to avoid the cliff edge of zero. Specifically, this would ensure that the newest generators are prioritised in the day-ahead market. Since finance always discounts for time (and uncertainty), this would seem to result in the most efficient finance (lowest cost-of-capital), compared to a situation in which offtake uncertainties arise from day one of contracts.

By prioritising offtake "from newest to oldest" in this way, alongside reducing the cost-of-capital, the obvious corollary would impact the value of a 5-year extension: for a given generator, day-ahead offtake uncertainties would grow over time, making a 5-year extension less valuable than it otherwise would be; instead, there would be a growing need over time to find other routes-to-market than bidding in the day-ahead market.

Costs / unintended consequences

29. Do you agree that increasing contract term for CfD assets would increase wholesale electricity price cannibalisation? Yes or No? Please explain why, providing evidence where possible.

Yes, given zero price rule.

It is hard to see any other outcome, as with standard CfDs, the frequency and scale of herding at zero price would inevitably rise over time, for as long as those CfDs operate.

Note also, it seems implausible that storage or other absorptive flexibility could realistically scale to alleviate this consequence. UCL studies of 'optimal' systems in 2050 indicate total VRE capacities in the range of 200 GW (wind) and 100 GW (Solar).[8] Even accounting for electrification of most end-uses, demand never reaches close to such levels. The optimal systems do, therefore, include spilling of surplus renewables at times of high output. Increasing periods of zero wholesale prices seem hard to avoid anyway; with 20-year CfDs it seems likely that this would become the norm during the 2040s.

31. Do you consider that increasing the contract term would materially increase overall investor confidence in the renewable electricity industry? Yes or No? Please explain why, providing evidence where possible.

(Likely) No.

Projects with 15-year contracts are already 'bankable', but they have a respectively higher cost of capital, compared to 20-year contracts. Investors would presumably take some view on risks to the final five years of contract, whether from the scale of cannibalisation, or risks of structural or legal challenges under future governments.

[8] https://www.ucl.ac.uk/bartlett/energy/sites/bartlett_energy/files/greenlight_mbarrett_041023.pdf

32. Do you consider there are any unintentional consequences that this policy change could create which have not been considered within this consultation? Yes or No? If yes, please provide evidence where possible.

Yes. At least three things merit some consideration.

a) Longer CfD contracts mean more money paid out in total. This could be used politically to counter the immediate benefits of cheaper CfD prices by pointing to the larger overall costs of contracts (i.e., smaller versions of the Hinkley Point C dubbed “£85bn+” total contract cost). Borrowing from the Danish Thor wind farm auction, total caps on the money paid from the LCCC to the generator or vice versa (which might indirectly also constrain the scale of "zero price herding"?).
b) In our answer to Q22, we explained the likelihood of CfD generators herding at zero price bids in the day-ahead market. Notwithstanding the value of investor security, it is vital that DESNZ fully understands and considers the implications of extending this pattern through towards 2050, implied by 20-year CfD contracts.
c) In economic terms, there is an attractive feature of renewables investment emerging at present, in that the capacity of renewables coming off contract will grow over the next few years (probably 5 -10GW by c.2030). This could visibly inform a political narrative that our past investments in renewables is now paying off, with a growing volume of extremely cheap generation. From the early 2030s, this will include generation from the first CfD contract rounds. The implication of 20-year CfDs is that, for new investment, consumers would not see this benefit until almost 2050, because they would still be paying the CfD strike price until then. This potential narrative drawback should be considered.

Finally, a move to 20-year CfDs – especially if combined with repowering CfDs – would suggest that the government has no ‘exit strategy’, and that the entire sector will depend on government decisions and government contracts, rather than market connection of generation with demand value. Whilst 20-year CfDs have a clear financial and legal attraction, this may strategically make investors uneasy about the policy and political sustainability of UK energy policy.

Implementation

33. Considering the factors of i) the impact on the wholesale market and security of supply, ii) the impact on CfD strike price bids and billpayers, and iii) overall investor confidence in the renewable electricity industry, in your view, what contract term best balances these factors? Please provide evidence to support your view.

The UCL Centre for Net Zero Market Design has not yet reached a consensus view on this. Our submission has aimed to lay out the many factors that DESNZ needs to consider.

34. Do you consider that an alternative approach to price indexation (currently CPI) may be required in any additional years of the contract to better balance the risk between generator and consumer? Yes or No? Where possible, please set out which mechanism you believe is most appropriate and why.

Yes.

Indexation to the Producer Price Index (PPI) would better reflect the price pressure than CPI.[9] Alternatively, indexation to raw commodities and labour cost would also work, as employed by NYSERDA.

35. Do you consider that increasing the contract term from 15 years should apply to all renewable technologies currently supported under the CfD? Yes or No? Please explain why, providing evidence where possible.

Fair competition between the technologies happens (implicitly) through the auction results in different pots. Technologies with a lower headline CfD (i.e., the one with longer contracts), may be politically more viable than others, though opposition could point to the larger overall contract cost and apparent enduring need for dependence on government contracts (=> Q32). These would seem to be considerations across most renewable technologies, though some (eg. tidal lagoons??) might benefit from particularly long time horizons.

Chapter 4.1 - Repowering of onshore wind

42. Do you agree with the proposed changes to the Contract Allocation Framework proposed above? If you disagree, please tell us why and support your answer with evidence.

No. Would have preferred if there were a "not sure" option, but the issues seem as follows.

1. Need to distinguish whether repowering goes into a separate auction. It seems likely that new build would be more expensive than repowering (additionally so if existing wind is on sites with the strongest winds)? If joint auctions with new onshore, does one then risk giving additional profits to projects that have already made a lot of money on ROCs (particularly, given the highs of energy crisis). If there's a separate auction, how is it defined? How the government precisely defines repowering will largely define what companies do? Also - a dilemma is that an auction only works if someone doesn't win. Yet, it would be a poor outcome if some sites simply closed down. Need to understand the implications of both avenues - those who lose out in a single auction are probably those with highest repowering costs and therefore those most likely to shut down without a CfD.
2. Is there a chance of doing a pilot on this? Risk is low auction liquidity.
3. See our responses to questions on a move to 20-year CfDs. This includes crucial observations on the problem of herding at zero day-ahead bid price given the negative price rule. Clearly, this would be exacerbated further in the event of CfDs for repowering.
4. There is in principle, a huge narrative benefit in terms of windfarms coming to the end of their current contracts - in principle, they should offer a flow of very cheap electricity,

[9] (https://reports.electricinsights.co.uk/q2-2023/offshore-wind-held-up-by-the-inflation-storm/)

and could be taken as a visible demonstration of the longer-term benefits of investment in renewables. It would seem that repowering CfDs would clearly put questions over this benefit, and would greatly exacerbate the additional narrative challenge that we point to in our response to => Q32

The UCL Centre on Net Zero Market Design is currently embarking on more comprehensive research around options for post-contract generation (which are not confined to just merchant operation on wholesale. Unfortunately, this research will not be available (beyond a scoping study) in time to aid DESNZ in decisions relating to repowering in AR7.