Accelerating Offshore Wind Deployment through Reform of Contracts for Difference

UKERC Discussion Paper

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October 2024

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1. Summary

Offshore wind (OSW) is expected to play a major role in the UK's ambitions for power sector decarbonisation. Over the short and medium terms, policy changes offer the potential to accelerate the deployment of OSW projects, provide greater certainty to developers and the supply chain, and help reduce the total cost to consumers of OSW roll out. These changes include the way Contracts for Difference (CfDs) for OSW projects are allocated, together with seabed leasing, environmental permitting and consent, and expansion and management of the grid.

CfDs will play an important role in the continued roll-out of offshore wind. The report focuses on potential changes to CfD allocation processes, contract duration and terms, and pass through of network costs that have the potential to accelerate OSW roll out and/or minimise CfD prices. CfDs have been the primary policy tool used in the UK over the past decade to support growth and cost-reduction of OSW, taking it from a relatively expensive emerging technology to a mature industry able to deliver cost-competitive electricity at scale. As a result, the principal purpose of CfDs is now to reduce wholesale market price risk rather than to provide subsidy. The desire to balance the advantages of risk reduction for investment against the need for wholesale prices to send operational signals is at the heart of the Review of Energy Market Arrangements (REMA). Substantive changes to CfD contracts are under consideration as part of the REMA reforms, and we summarise these proposals in Annex 1. However, the report does not consider the REMA proposals in detail, focusing instead on CfD allocation mechanisms.

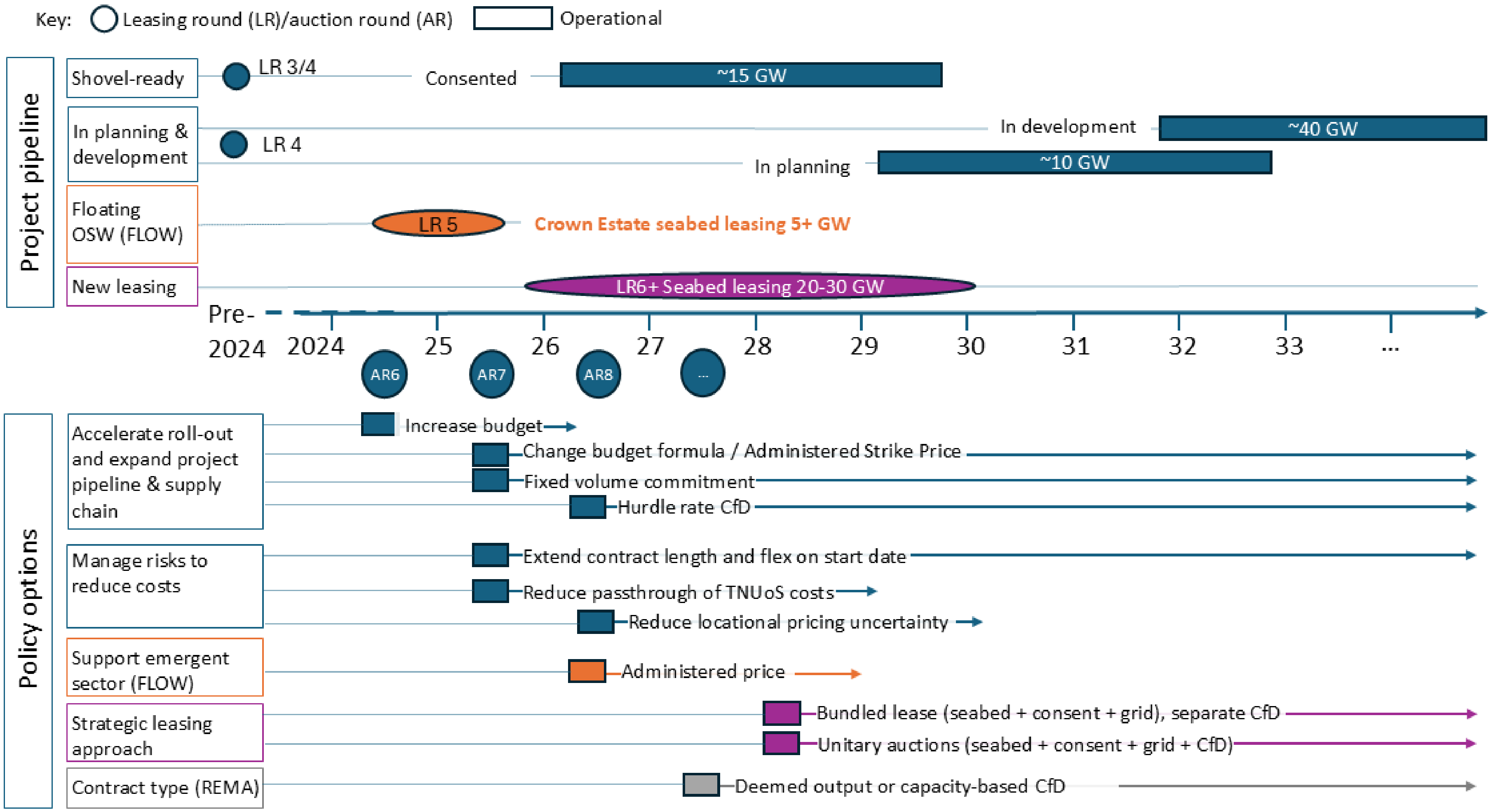
The options for modifying CfD allocation start with relatively simple **near-term actions that can be taken in the to accelerate the estimated 15GW pipeline of shovel-ready projects** that have already gained seabed leases and agreed grid connections, and now just await CfD contracts. For these projects, the biggest opportunity to accelerate deployment is to provide a greater degree of certainty over the volume of contracts that government intends to commission over the next 3 rounds of CfD auctions. There are also simple opportunities to reduce the pass-through of project costs to consumers for these projects by altering the terms of the contracts, as well as potential to re-think how network charges are handled in the auction process.

In the medium term, there are opportunities to **accelerate the development of around 50GW of OSW currently in the planning phase**. For this cohort of projects, the most pressing need is to accelerate the build-out of transmission infrastructure and improve certainty over grid connection dates for OSW projects. Design changes to the CfD could also contribute to the acceleration of project development. Options to be considered include a 'hurdle' rate CfD where the strike price is set for several years ahead rather than through annual auctions, providing greater visibility and certainty to the market, and allowing a more strategic approach to project and supply chain development. One way to reduce the pass-through of costs to consumers for this cohort of projects is to remove uncertainty over how locational pricing will be handled in future, and to consider alternative ways of handling certain projects costs (e.g. radar mitigation).

More significant changes to the CfD process will need to be considered for the **new cohort of projects that will start to be planned as part of the 20-30GW of new rounds of seabed leasing** announced by The Crown Estate. This new round of leasing will take a more strategic approach to site selection by integrating consideration of environmental impacts and grid connectivity which could considerably reduce project risks and shorten development times. In this context, a more site-specific approach to CfD auctions may become appropriate. Finally, options are presented for CfD designs for floating offshore wind (FLOW) that are more supportive of the development of the supply chain for this less mature technology.

More policy details and a potential timeline for their implementation is shown in Figure 1. The mapping of policies to the project pipeline is indicated by the matched colours. Policy options shown are not all mutually compatible, so choices will be needed taking account of the pros and cons discussed in the report. Many of the choices reflect increasing coordination and planning. The OSW sector is operating in a highly-planned environment. Whilst not without risks, there are upsides - in terms of pace, scale and cost – from explicitly recognising the planned nature of the sector, at least over the next decade, and embracing the advantages of a more directed and strategic approach to offshore wind development.

Figure 1: Summary of CfD policy options



TNUoS = Transmission Network Use of System Charges

2. Introduction and case for change

This paper sets out options for near-term and medium-term reforms to improve the effectiveness of the UK's principal mechanism for renewable energy support, the 'Contracts for Difference' (CfD). The two key objectives of such reform are: i) to facilitate a step change in the deployment of established clean power technologies in pursuit of the UK's clean energy targets; and ii) to reduce costs to consumers.

The paper draws on previous research together with two stakeholder workshops held under Chatham House rules on the 17 May and 7 June 2024, co-convened and led by UKERC and the Royal Academy of Engineering. Participants were selected to represent a broad range of views across the industry, including investors, project developers, industry trade bodies, policy advisers and independent consultants.

The report addresses offshore wind, with a focus on mature fixed-bottom technologies. The UK Offshore Wind (OSW) sector is recognised as an international success story.[1] There has been rapid increase in scale and decrease in costs in the past 10 years,[2] to the point where it is now amongst the lowest-cost forms of power generation in the UK.[3] With competitive costs and a very large potential resource, OSW is expected to be the largest source of power generation under most UK decarbonisation scenarios,[4] hence the focus on this technology in this report.

Historical and future role for CfDs

Since 2016, the levelised cost of electricity from OSW fell from over £100/MWh[5] to around £60/MWh in 2020,[6] falling to below £50/MWh,[7] although bid prices increased slightly in the most recent CfD auction.[8] CfDs are recognised as a key driver of cost reductions over this period,[9] with auctions acting as a competitive cost driver, and significant volumes of long-term fixed price contracts helping to drive economies of scale and acting to significantly reduce the cost of capital for financing projects.[10]

Workshop participants agreed that going forward, OSW faces competing cost pressures. Whilst the maturity of the technology means that many of the quick wins have already been made, there will continue to be modest gains from economies of scale in supply chains and increased efficiencies from new generations of turbines, and from more strategic development of multi-purpose interconnectors.[11] Conversely, in the short-term the sector is facing global commodity price increases,[12] and in the longer term as the sector grows, projects will be pushed out to more challenging sites which will tend to push up costs. Combining these different drivers, the official outlook on costs for the next decade remains relatively flat from today's levels,[13] although some workshop participants were anticipating moderately rising real term costs over this period overall.

As technologies have matured and cost trajectories have flattened, the role of CfDs has changed from one of subsidy to one of revenue and cost stabilisation for producers and consumers respectively. CfD bid prices are currently broadly similar to average wholesale power prices, and during the recent gas price escalations CfD contracted generation offered some protection to consumers from electricity price hikes.[14] This is leading to a reappraisal of CfDs as a mechanism to more efficiently allocate risk in the sector to help create a more secure and cost-effective basis for industry to deliver the bulk roll-out phase of OSW.[15]

The purpose of the workshops was to discuss potential changes to CfDs that would facilitate this future role, with options identified that would contribute to two overlapping policy objectives:

i) **Reducing the overall cost** to consumers of scaling up offshore wind by reducing project risks and the thereby the cost of capital. Options to achieve this goal mainly relate to changes to the way CfD contracts are allocated, and some adjustments to the way auction parameters are handled.

ii) **Increasing the speed and certainty of roll-out** of OSW projects, reducing the risk of failed auctions, and improving the forward visibility of volume for the supply chain. This second objective may also help build UK-based capacity and manufacturing.

Longer-term strategic options for reducing sector costs are also discussed.

The design options considered here are separate from those discussed in the Review of Electricity Market Arrangements REMA.[16] The REMA options were not extensively discussed at the workshops, since those options focus principally on enhancing operational efficiency rather than the cost and delivery goals outlined above. In addition, they have already been discussed as part of the REMA consultation process and workshop participants felt they had already had opportunity to feed in views on their relative merits. Those options, which are covered briefly in Annex 1, entail changes to the terms of the CfD contracts, and could be implemented independently of the changes discussed in this report.

Types and timescales of CfD reforms

Accelerating project delivery will require reforms to the CfD allocation process (Section 2). Options range from relatively simple near-term changes to auction budget parameters to help to pull through shovel-ready projects, through to more fundamental reforms that could provide greater certainty and support investment in the supply chain to achieve long-run efficiencies.

Near-term options to reduce project costs and cost pass-through to consumers (Section 3) include relatively simple changes to the CfD contract terms that could be implemented in the short-term. Options are also set out for more substantive medium-term changes to the way locational pricing and other development costs are bundled into CfD prices at auction could also help reduce CfD strike prices and improve value to consumers.

Over the longer-term, streamlining and derisking the planning process (Section 4) can deliver significant improvements to the efficiency of sector development and improve consumer value. The Strategic Spatial Energy Plan will play an increasing role in OSW project selection, as the current approach of choosing projects first and building out the grid in response hits physical and environmental limits. Moves to derisk and streamline OSW planning processes, combined with strategic grid planning, will further centralise the process of defining the location and other characteristics of projects in the pipeline, which could lead to a greater role for locational CfDs, with options to move to a more integrated approach to seabed leasing and project auctions.

Floating Offshore Wind (FLOW) is at an earlier stage of technological development, but offers exciting opportunities to open up large new areas of sea space, both in UK waters and around the world. As the policy issues for emerging technologies are rather different, we discuss FLOW separately, in Section 5.

3. Accelerating near-term deployment by derisking CfD allocation

This section considers options for increasing the volume of projects to be pulled through, balancing the need to accelerate the rate of scale-up of OSW, whilst maintaining a sufficient degree of price pressure to achieve value for money for consumers.

Key messages and recommendations:

- Near-term changes to the **budget-setting** process could help pull through shovel-ready projects in the next few auction rounds.
- A **fixed volume commitment** setting the capacity to be contracted in forthcoming CfD auctions (AR 7-9) would significantly increase investor and supply chain confidence.
- A more substantial change to a **'hurdle-rate' CfD** would take this a step further by providing forward visibility of the strike price, helping start commercial negotiations earlier, and giving the supply chain more investment certainty. This may take time to implement as mechanisms would needed to be developed to adjust the hurdle-rate over time.

Budget-setting

CfD auctions have two mechanisms that were designed to protect consumers from overpaying in the context of the CfD's historical role as a subsidy.[17] The first is a reserve price, called the administrative strike price (ASP). The second is a budget cap intended to limit the total 'subsidy' paid to renewables via the CfD.

However, going forward these mechanisms introduce fragilities that may reduce the effectiveness of CfDs as a risk-management tool. This is illustrated by the failure of the fifth CfD auction round (AR5) in March 2023 to deliver any offshore wind projects because the reserve ASP was set too low to recognise the recent commodity price pressures in the sector.[18] This knocked investor confidence, potentially putting at risk the ability of the sector to deliver strategic investments that could deliver long-run efficiencies and consumer value.[19]

The following options represent ways to address these constraints and help avoid a 'stop-start' approach to sector development. Options are outlined starting with the simplest that could be implemented quickly, and moving to more substantive medium-term options.

The ASP is intended to cap prices, mitigating the risk to consumers that auctions are not sufficiently competitive to achieve downward price pressure.[20] This is a likely concern in a market with a limited pipeline of projects. In a mature market such as fixed-bottom OSW, the pipeline is well established and quite visible to all parties due to the leasing, consenting and grid connection process. In this market, the ASP arguably plays (or could play) a much less significant role in consumer protection. The ASP is currently set based on an assessment of the expected costs of generation from pipeline projects. The key risk to the market is that the ASP may be out of line with real-world costs such as were seen in AR5. This risk could be alleviated by **setting the ASP at a significantly higher 'willingness-to-pay' level** rather than an estimate of potential auction bids. This would not adversely affect consumer outcomes as long as other procedures were put in place to ensure competitive auctions.

The AR budget limits the volume of projects that can be allocated in the auction and is a key determinant of competitive pressure in the auction. It is based on the difference between the auction strike price and a notional calculated reference price. The logic of the budget-setting process derives from the 2011 levy control framework, when renewable energy costs were much higher and HM Treasury needed to put limits on the subsidies for renewable energy that consumers paid over and above market prices under the previous Renewables Obligation (RO) and microgeneration Feed in Tariff schemes.[21] However, with CfD prices competitive with market rates, unlike payments through the RO (which were always additional to wholesale prices), it not clear that the original rationale for the budget constraints are still applicable.

This lack of clarity over the degree of subsidy embodied by CfDs is also reflected in the complexity of the methodology for calculating the auction budget, which contrasts ASP with a supposed market reference price. The reference price used is the 'capture-price' that OSW is expected to receive in the market in future. This takes account of price cannibalisation which is a structural effect on the market caused by large penetrations of low-marginal cost generation.[22] Price cannibalisation occurs in these circumstances because the market price does not fully reflect the total cost of generation. This means that consumers will at the margin benefit from below-cost prices. Using this below-cost price as the reference means that rather than acting as a subsidy, the CfD auction budget can be considered at least in part as acting to correct this shortfall, allowing generators to recoup the long-run marginal costs of generation.

For AR6, budget rule changes could not be changed, but the size of the budget is within the power of the Secretary of State to change. Under the new administration, in July 2024 the budget for offshore wind was increased from £800m to £1100m.[23]

For later ARs, **more accurately representing the true subsidy element of the CfD in the budget** could significantly reduce the impact of HM Treasury spending limits. Reforming the budget-setting process would require changes to reference price and/or Treasury imputed tax methodologies, but would not require changes to the CfD or auction process itself. As a result, the change could potentially be made quite quickly, and would not affect project development processes. Such a change would allow policymakers to focus on balancing the two main substantive factors in the budget setting process: protecting consumers by maintaining price pressure in the auction; and pulling through sufficient volumes of projects to meet energy needs and decarbonisation goals.

Fixed volume commitment

This option would remove the AR budget element completely and replace it with a **fixed volume commitment** for each auction round **(e.g. GW commissioned)**. Auction pressure would be maintained by setting the fixed volume targets below the level of the anticipated size of the pipeline so that only the more efficient projects would be pulled through. In practice, fixing volumes to maintain adequate price pressure would require the same considerations and analysis as fixing the budget, so this would be a relatively incremental change to the process.

A fixed volume commitment was considered likely by workshop participants to have more impact than simply raising the budget level in terms of regaining momentum in the market as it would provide greater certainty over the size of the forthcoming project pipeline. However, due to uncertainty in the budget implications of fixing volumes, this option does imply a change in the allocation of risk as it would reduce the state's control in terms of capping payments to the sector. The degree of material risk this presents to consumers is debateable, linked to the question raised above about the extent to which CfDs represent a subsidy vs. a cost stabilisation mechanism.

Hurdle rate CfD

A more substantive option to provide greater support to the supply chain would be the introduction of a **'hurdle-rate' CfD** as set out in the independent report by the UK's Offshore Wind Champion.[24] This would provide the market with a predetermined strike price, with a guaranteed contract for any project that was able to deliver power within that price threshold.

This mechanism will take more time to develop and is therefore likely to be of most value to the ~50 GW cohort of projects currently in the planning process, although there could be options to bring this reform forwards to also apply to the 'shovel-ready' cohort. Workshop participants were in general agreement that the forward visibility of the strike price under a hurdle-rate CfD could help remove a significant level of risk that currently arises from having to wait until near the end of the project development process to establish the route to market. Project developers under this approach would be able to start commercial contract negotiations in parallel with the other phases of project development, creating a greater visibility and longer runway for supply chains to invest and scale up their ability to deliver.

However, a potential downside is the additional complexity involved in agreeing a strike price that achieves a suitable balance between the interests of developers and consumers. Mechanisms would need to be developed to set and regularly review the CfD strike-prices. Options include:

- **Auctions**. The frequency of auctions would need to be assessed to see if it would be perceived as more or less risky or effective than the currently envisaged approach of implementing annual auctions. Concerns about the possibility of gaming (e.g. by withholding projects from auction) would also need to be addressed.
- **Administrative pricing** (e.g. open-book accounting). This would have the advantage of being able to take account of dynamics of market variables (raw materials prices, interest rates etc.), but may lose the competitive price pressure and costs discovery element of auctions.

4. Reducing cost pass-through to consumers

Some of the costs of financing OSW projects are associated with policy risks that are within power of government to reduce, which could in turn reduce the cost to consumers. This section explores these options.

Key messages and recommendations:

Contract terms:

- Increasing flexibility of **delivery dates** post-auction would allow a more strategic approach to project development that could help support the supply chain
- Increasing the **contract length** of the CfD would reduce tail-risk for developers and consequently would likely reduce the CfD price.

Treatment of TNUoS in the auctions:

- In the short-term, changing the way TNUoS charges are handled in CfD auctions may help to reduce unhelpful rents in the sector, and reduce costs to consumers. This could be done by treating them as a **pass-through cost**, or by **splitting the auction stack** to achieve give more than one strike price depending on location.
- In the medium term, reducing risk associated with uncertainty over future TNUoS charges and future locational pricing would help reduce project costs that are currently passed through to customers.

CfD contract terms

Two relatively simple reforms to CfD contract parameters could be made in the short-term to reduce project costs and costs to consumers. These changes are broadly independent from the allocation mechanisms discussed in Section 2, and so could be carried out alongside those.

Increasing the duration of CfD contracts

The design life of wind turbines is increasing, and revenue risk (including the degree of price cannibalisation) during the latter part of the operation of the assets once the 15-year CfD contract has expired is becoming a more significant factor in project finance.

Writing down the value of the assets during this latter period tends to increase CfD prices as there is pressure to recoup revenues during the shorter contract period.

Increasing the CfD contract length (for example from 15 to 20 or 25 years) could therefore reduce the cost of capital (and the CfD strike price) with consequent benefits for consumers. Previously published research funded by UKERC indicated that this effect could be significant, reducing the cost of capital by one percentage point.[25]

Allowing more flexibility on project delivery date

This change could be implemented relatively simply by increasing the range of project delivery years included in the auction. It would bring forward projects that are later in the queue into earlier auctions which would have to be taken into account when setting the auction volumes.

The upside of this is that it would allow project developers to work more strategically with the supply chain, potentially enabling aggregation or stacking of multiple projects either into larger orders, or more planned phased orders giving the supply chain more visibility and scale in the project pipeline.

One downside is that it could reduce certainty over when projects would be delivered. The group discussed whether additional incentives were needed, but group felt these were already adequate with the TCE annual option fee, plus commercial incentives to start projects earlier when possible.

Treatment of locational charges in CfD auctions

Upgrading the transmission system is a key element of the energy transition. Minimising total future system costs requires a long-term strategic view of the optimal locations/regions for offshore wind and other renewables, taking account of the wind resource, environmental impacts, competing uses for land/see space, planning considerations, and the cost of the associated grid infrastructure. Moves are being made in this direction with the Strategic Spatial Energy Plan (SSEP) discussed in Section 4.

For the time being, spatial price signals are sent to the market through Transmission Network Use of System (TNUoS) charges. TNUoS charges are set to reflect the current costs of operating and maintaining the system. This means for example that Scottish wind projects are charged significantly more than projects in England and Wales (E&W).

These higher TNUoS charges are in turn factored into the Scottish projects' CfD bids, which effectively inflates the marginal pay-as-clear prices paid to all projects in the auction. Further work is needed to assess extent to which this distorts the selection of projects compared to a system-optimal outcome, taking account of the potential for a more strategic approach to grid reform and build out, in particular strengthening the connectivity between Scotland and E&W. To the extent that current TNUoS arrangements may not lead to system optimal project choice, reform could help reduce overall transition costs to consumers.

In the short-term, one option that could be taken independently of reforming TNUoS itself (which would be a longer-term option) is to **treat TNUoS charges as a pass-though cost** – i.e. removing them from the costs that are bid into CfD auctions, and adding them back in afterwards. This would effectively reduce the bids of the more expensive projects at the margin of the auction stack, which tend to be the high TNUoS Scottish projects. This would not only reduce CfD strike prices, but would act to reduce what might be considered some degree of excessive producer surplus paid to projects in E&W under current auction design.

However, completely removing TNUoS costs from auction bids may be a step too far, making the Scottish projects look more attractive than they really are given the higher network costs of delivering them, which could distort the selection of projects. Some degree of locational signal is likely to be needed in the project choice in order to achieve least system cost.

An intermediate option would be to **split the auction stack** so that it achieves separate strike price for the particularly high TNUoS projects. The mechanism for doing this is already established. For example, where AR4 projects that have been resubmitted to AR6 under the 'permitted reduction' mechanism are in the same volume stack as other projects, but are being ringfenced so they can only uplift each other and do not receive the overall stack clearing price. This can act to reduce rents, but a trade-off with this approach would be increased complexity, and potentially smaller and less competitive auctions, as well as some arbitrariness over how to define the boundaries of the separate auctions.

In the medium-term, work is ongoing under REMA to assess ways of accounting for locational costs,[26] including a review by Ofgem of options to reform TNUoS to better reflect locational pricing.[27] It is recognised by government[28] that uncertainty created by this reform to TNUoS charges is creating risks (and therefore costs) that are being priced into CfD bids in the auction.[i]

Similar risks also arise in relation to uncertainty over implementation of locational pricing as part of the REMA review. **Removing or reducing these risks by resolving the policy uncertainties** would be one way to reduce the pass-through of these costs to consumers, though implementation of substantive changes to locational pricing may take time.

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[i] In the AR6 ASP methodology, a risk premium of 2% is added to the hurdle rates of Fixed and Floating Offshore Wind to reflect the uncertainty of longer term TNUoS charges and wider cost uncertainties. A risk premium of 1% is added to the hurdle rate of Onshore Wind to reflect only the uncertainty of longer term TNUoS charges.

5. Long-term cost reductions through strategic planning

This section looks at the opportunity to take a more strategic approach to planning, streamlining processes to reduce risks and lower project development costs.

Key recommendations:

- For the approximate 50 GW of projects currently in the planning phase, the most important action is to accelerate transmission investment and reform the grid connection queue
- A further 20-30 GW of new seabed leasing by 2030 has been signalled by The Crown Estate (TCE)
- For these projects, there is scope for more fundamental reform of the planning process to streamline the development and approval, and take a more strategic approach to site and project selection
- This will require greater coordination between key institutions including TCE, Crown Estate Scotland, the Environment Agency, DESNZ and the ESO
- Decisions will be needed regarding how far to go down this path towards a more regulated and planned approach

Strategic grid planning

For the approximate 50 GW of projects currently in the planning phase, the two most important actions are: i) **to speed up the building of transmission upgrades**, and ii) **grid connection reforms** which prioritise projects in the queue which can demonstrate deliverability (e.g. consents, land/seabed rights, supply chain capacity) and are critical to net zero pathways. This includes much of the capacity arising from the ScotWind and Innovation and Targeted Oil & Gas (INTOG) leasing rounds in Scotland, as well as some of TCE leasing round four (LR 4) in E&W. Workshop participants recognised the significant progress made in reforming grid connection queues in the UK,[29] although identified remaining risks associated with uncertainty over grid connection dates.

Looking ahead to future leasing rounds, there is a potential to significantly improve the linkage between grid planning and project site selection through a more strategic and integrated approach to planning of offshore resources. As part of this approach, TCE announced in the 2023 Autumn Statement between 20-30 GW of new leasing by 2030, to delivered by 2040. This signalling of a longer-term timetable for future leasing rounds has partly been in response to lessons learned by comparing ScotWind with previous leasing rounds in E&W. ScotWind provided a greater visibility of the pipeline of projects in Scotland by leasing a large volume of seabed at the same. This had some advantages compared to more staged E&W auctions, in that it provided visibility of a large volume of projects to give confidence for the supply chain. However, the downside is it has meant that current grid roll-out plans may be skewed towards those visible projects in Scotland and less likely to capture more strategic considerations around the future pipeline of projects that have not yet been leased in E&W.

For leasing round 6 and beyond, the need for a more strategic approach to grid development will play an increasingly important role in the way projects are selected and awarded contracts. Significant steps have already been made in this direction, with the Electricity System Operator's Holistic Network Design (HND) and Beyond 2030 reports providing grid connection dates for 50 GW of OSW projects in the pipeline. The Strategic Spatial Energy Plan (SSEP) and Centralised Strategic Network Plans (CSNPs) will be a further step in the direction, providing greater contractual certainty over connection dates, and helping to coordinate OSW developments with other related marine infrastructure.

This will lead iteratively to a greater degree of alignment between transmission development and the choice of sites to be developed for OSW, which in turn will have a big impact on the way OSW is planned and procured. Taking this to its logical conclusion, in a world where decisions about the location of the grid have already been made, wind projects will need to be built in these same locations. In this scenario, it may no longer make sense to hold geographically neutral CfD auctions, instead auctions may need to become more project- or location-specific.

Participants also discussed the need for greater coordination across Northern Europe to account for structural changes in the energy system at a continental level including through greater collaboration with the North Seas Energy Cooperation group.[30] Key issues include coordinating the balancing of supply and demand, linking spatial planning (including linking ENTSO-E with SSEP as well as coordinated marine spatial plans for the North Sea). Coordination needs to include assessment across multiple sectors, not just OSW, including the role of hydrogen pipelines, and to consider the UK's role in integrating plans for OSW in the island of Ireland with Continental Europe.

Streamlining and accelerating the planning process

For seabed leasing round 6 (LR6) and beyond, reforms to the planning process are being considered that could accelerate and de-risk the development process, potentially resulting in faster and lower-cost delivery of the pipeline. Various streamlining steps were enacted the 2023 Energy Act and Levelling Up Act. The impact of those reforms are yet to be seen as they are only just starting to be implemented, but they are broadly aligned with the concept of more plan level work being done by TCE, including more strategic approaches to compensation with an option to implement compensation via paying into a central "marine recovery fund".

There is potential for a much greater degree of coordination between the major agencies involved in the process, so that streamlining decision making is clear between multiple agencies (particularly TCE, CES, the Environment Agency, DESNZ and the ESO).

A big option here is to **bundle together the consenting and grid connection approvals into the seabed leasing process**. This would ensure that the seabed leases were aligned with the SSEP grid rollout plans.

On consenting, a key step would be to agree a plan-level Habitats Regulations Assessment (HRA) for each leasing round that would provide substantial cover and derisking of the subsequent project-level HRAs. This would require plan-level HRAs to define key design criteria that projects would have to follow (or show equivalence to), including e.g. foundation type, turbine size etc.

Taken together these reforms would mean the UK is heading towards a much more pre-planned system, in terms of the location and specification of future projects. To some extent this may be an inevitable consequence of the need to take a more coherent approach to grid rollout and marine spatial planning as we reach increasingly large volumes of OSW.

As well as potentially speeding up projects, this would significantly change the nature of project development, with much decision-making and risk-taking that is currently taken by private project developers essentially shifting across to the state. This would have certain pros, cons and byproducts:

Pros	• Consolidation and streamlining of the consenting process at the wider plan level could be quicker and more efficient, reducing costs to consumers • Reducing risk in the project development process could also reduce the costs (and room for profits) of project development, which could reduce costs to consumers • Specifying key project characteristics at the plan level could help the supply chain consolidate around particular technology specifications could help achieve economies of scale.
Cons	• This could reduce the scope for innovation by project developers which could reduce project-level efficiencies.
Byproducts	• This approach might attract a different set of project developers. The scope for decision-making, risk-taking and consequent profit-making would be reduced, and the task would become more focused around routine project delivery • This might also attract a different set of upstream investors.

The process for allocating CfDs will likely need to adapt to the above changes. A shift towards greater specification of the location and design of projects in the planning process will lead to pressure to prioritise those projects in the allocation of the CfDs. The design of the CfD in these future rounds might consequently need to take greater account of the differences in cost structure associated with projects in different locations. Conversely, the implied standardisation of project design characteristics and derisking approach may result in a reduced scope for price discovery from the CfD auctions.

One option, which would take this approach to its logical conclusion, would be to **combine the CfD auctions with the seabed lease auctions**. This would result in a series of project-level auctions that would include the grid connection agreement, consents, seabed and CfD in one unitary process. Similar approaches are taken in various countries in Europe. This would have the advantage of creating a clear pipeline of derisked projects that would be aligned with strategic spatial planning, which could send strong signals to the supply chain and infrastructure developers.

However, a downside to bundling the CfD auctions with seabed leasing would be that it might remove innovation and optionality in developing different routes to market, including for example Corporate PPAs, Green Hydrogen, Power-to-X and other merchant alternatives to the CfD.

A significant factor facing the sector is the degree of coordination of approaches taken in Scotland and E&W, particularly the degree to which grid development and consenting is can be jointly agreed and accelerated. This will affect the viability of options discussed above regarding the potential bundling of CfDs with seabed leasing.

The workshop discussed the idea of **mega-projects (single projects above 15GW each**) raised by the Offshore Renewable Energy Catapult.[31] The pros identified for this approach is that it could provide a bigger runway for the supply chain, allowing them to more easily exploit economies of scale. The cons identified were that delivering these as a single project might prove unwieldy, and could actually slow down the development process. In practice they might need to be split up into manageable chunks which would essentially bring us back to the status quo.

Treatment of radar mitigation costs

Another planning reform to consider which could streamline the development process and reduce the cost of projects would be to **remove the burden of the radar mitigation** from the sector,[32] and shift the responsibility for coordinating and funding this to the MoD which could carry out the function in a more strategic way aligned with future marine spatial planning. This would remove this cost element from the CfD auction bids, acting to reduce CfD strike prices, although the costs would have to be picked up elsewhere in the public budget.

6. Tailored approaches to floating offshore wind

Key recommendations:

- Up to 4.5 GW of floating offshore wind projects are being leased in the Celtic Sea (delivery after 2030), together with 19 GW in Scotland under the ScotWind[33] and 5GW under the INTOG leasing round aimed at supplying offshore oil and gas installations[34]
- The technology and infrastructure for delivering these projects is relatively less mature, making project costs more uncertain
- In this context, an administered price approach, similar to the FID-enabling CfD used in the early stages of development of deployment of fixed-bottom offshore wind projects may be the most appropriate way to bring forward this pipeline of projects.

Up to 4.5 GW of seabed leases for floating offshore wind (FLOW) projects in the Celtic Sea could be developed under TCE Leasing Round 5. FLOW is relatively less mature than the fixed-bottom projects implemented in earlier rounds. In addition, the infrastructure for delivering OSW projects into the Celtic Sea are significantly less developed than for equivalent projects in the North Sea. It will only make sense to build out such infrastructure, such as port facilities and associated supply chain manufacturing facilities, together with the required human resources, if there is firm visibility of the project pipeline. Without this ecosystem, FLOW in the Celtic Sea may not achieve economies of scale needed to bring down costs.

Removing inter-technology competition by having a ringfenced CfD for FLOW auctions is one relatively simple way to help strengthen confidence in the sector, and increase the visibility of the pipeline. However, sizing of the auction budget for AR6 is complicated by the fact that there is a mix of smaller ‘stepping stone’ test and demonstration FLOW projects together with the much larger “Green Volt” INTOG floating project in Scotland.

However, the workshop raised concerns that a competitive CfD auction may not be the most cost-effective process for these projects to achieve a route to market. Instead, one option would be to **move to an administered price process**. For example, this could follow a similar approach to the FID-enabling CfD that was used in the early stages of development of the fixed-bottom OSW projects. A suitable process of price discovery would need to be developed that balances the interests of consumers and the supply chain.

Actions to accelerate the planning process and speed up the roll-out of the required grid infrastructure will also be essential components of bring these projects to market quicker (as discussed in Section 3).

7. Conclusions

A key finding from this work was the emergence of a widely-held view amongst stakeholders at the workshops that the offshore wind industry is now at a critical and finely balanced stage where the industry is poised to be able to rapidly expand to meet the scale of national ambitions for decarbonisation. For better or worse, the key levers which can drive this accelerated rate of deployment lie in the hands of publicly-owned institutions and utilising them requires a greater degree of coordination and planning across public agencies (including the National Energy System Operator). These drivers include seabed leasing, environmental permitting and consent, management of the grid connection queue, and the route to market via CfDs. Improvements to all these drivers are needed to achieve the necessary acceleration of deployment.

Though not all workshop participants agreed in principle that CfDs should remain the dominant route to market for OSW (due to an implied reduction in competitive pressures), there was widespread agreement that given the highly-planned nature of the other key drivers, there is at least an internal logic for them to do so. Furthermore, many participants acknowledged that there are significant gains to be made – in terms of pace, scale and cost – from explicitly recognising the fundamentally planned nature of the sector, at least over the next decade, and embracing a more directed and strategic approach to sector development which reflects this reality. This includes the need not only to accelerate deployment of planned projects, but a more strategic approach to scale-up of the supply chain needed to service these projects, and to grid connection and environmental assessment.

Embracing this logic would justify an increased appetite for policy to derisk the project-development process. This would bring CfD allocation risk more into line with other risks in the OSW sector, where public institutions play a significant role in project identification and selection. Reducing the CfD-allocation component of project development risks is likely to be cost-efficient, could lead to net reductions in overall costs to consumers, as well as helping to speed up deployment.

This report has highlighted potential CfD allocation process reforms ranging from near-term quick-wins that could speed up deployment of shovel-ready projects and reduce the cost of these to consumers, through to deeper strategic reforms that can help maintain momentum and contain costs of deployment to offset cost pressures as OSW penetrates into deeper and more challenging remote waters.

The options for reforms are summarised in the table.

Time	Pipeline	Approx size	Lease Round	Design options to accelerate build out	Design options to reduce costs and cost pass-through
Near-term	Shovel-ready projects	15 GW	LR 3&4	• Improved CfD auction budget-setting creates greater certainty over route to market for shovel-ready projects, facilitating project development	• Reduce project risks by increasing CfD contract length and more flexibility on delivery dates. • Reduce pass-through of network charges (TNUoS)
Med-long-term	Projects in planning	50 GW	LR4, ScotWind INTOG	• Accelerate transmission infrastructure build-out and improve certainty on dates of grid connection[ii] • Replacing auctions with fixed price ‘hurdle-rate’ CfD creates longer line of sight for project and supply-chain development	• Reducing risks associated with uncertainty over how locational pricing will be handled in future reduces cost pass-through to consumers. • Remove pass-through of radar mitigation costs to consumers.
	New leases	20-30 GW	LR 6	• Strategic approach to site selection for seabed leasing by The Crown Estate, and improved coordination with grid investment plans creates greater certainty over deliverability and reduces project development costs.	
Med-term	Floating OSW	5+ GW	LR 5	• Administrative pricing improves certainty and line of sight to project development for the emergent supply chain.	

[ii] This is outside the scope of CfD design, but delays to grid infrastructure build-out and risks associated with the grid connection queue were identified as key barriers for this tranche of projects, so have been highlighted.

Annex 1: CfD design options considered under REMA

The current Review of Electricity Market Arrangements (REMA) is considering changes to the CfD contract to address a number of shortcomings with current design. The workshop only addressed these options briefly since they have been covered in detail in the recent REMA consultation in May 2024,[35] to which workshop participants have already submitted their responses.

Two key policy options discussed in REMA relate to the introduction of a capacity-based CfD (linking payment to installed capacity) or a deemed-output CfD (linking payment to a calculated output potential). Whilst their designs differ, they would both have the effect of removing the negative price rule that exists with the current CfD design. This is where the state is unable to make payments to renewables projects during times when the wholesale price goes negative. The negative price rule is imposed at least partly because of state aid rules, and whilst it has some theoretical advantages, it can lead to perverse incentives in the market, and overall increases project risk which previous UKERC research suggests could significantly raise the cost of capital by of the order of 2 percentage points.[36]

Broadly, there was support for the idea of taking away volume risk for project developers by effectively removing the negative price rule (i.e. where CfD payments are not paid to generators during hours in the year when prices become negative). Removing the negative price rule could help to reduce CfD prices because the volume risk would no longer be factored into auction bids. Part of the savings to consumers associated with this price reduction would be offset by the need to pay generators when prices turn negative. However, the reduction in risk would be expected to reduce the cost of capital, with real-terms reductions in system cost that should feed through to lower consumer bills.

However, this view was not unanimous – some argued that exposure to the negative price rule is positive because it helps to incentivise developers to find innovative ways to manage volume risk e.g. by developing storage solutions, and that there is evidence of this in practice under current arrangements.

There is also a potential reputational risk / risk of backlash associated with making payments to wind farms when they are not generating, but this may be offset by the associated reduction in CfD strike prices that would be expected.

Of the two mechanisms set out in REMA to remove the negative price rule, the ‘**deemed output’** option was considered by workshop participants to be the most appropriate. As noted in the REMA consultation, there are still many design factors and potential trade-offs to be resolved with the detailed design of deemed output contracts which the workshop did not delve into.

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