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Consultation on changes intended to bring about greater coordination in the development of offshore energy networks

Joint RenewableUK / OWIC response[1]

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About RenewableUK
RenewableUK's members are building our future energy system, powered by clean electricity. We bring them together to deliver that future faster; a future which is better for industry, billpayers, and the environment. We support over 400 member companies to ensure increasing amounts of renewable electricity are deployed across the UK and to access export markets all over the world. Our members are business leaders, technology innovators, and expert thinkers from right across industry.

About OWIC
The Offshore Wind Industry Council (OWIC), a senior Government and industry forum, was established in May 2013 to drive the development of the world-leading offshore wind sector in the UK. It is comprised of members drawn from the leading UK and global firms in the offshore wind industry, including developers and original equipment manufacturers. The Council oversees and drive the implementation of the Sector Deal

0. Introductory remarks

0.1. RenewableUK, OWIC and our members welcome the opportunity to respond to the Offshore Transmission Network Review's first consultation on changes intended to bring about greater coordination in the development of offshore energy networks. Prior to the publication of the sector deal, we highlighted the need to move away from the current regime, which encourages point-to-point radial connections, to a more coordinated offshore network, we noted that the "future deployment of offshore generation will benefit from a more sophisticated, innovative offshore transmission network, which the OFTO regime we have today may not be able to support"[2]. Industry agrees with government that the current regime based solely on point-to-point connections is no longer fit for purpose. The Sector Deal has picked this up and run with it, and we have strongly supported the work from BEIS, the ESO and Ofgem to lead us to this first consultation.

0.2. Below, we answer the questions in detail, but would also like to make the following broad points:

The importance of 2030 and net zero targets

0.3. The UK is committed to delivering net zero emission by 2050, and the CCC recommends all but decarbonising our power system by 2035. Offshore wind will be the backbone of this zero carbon power system, and the industry is committed to

[1] We would also like to thank Scottish Renewables and Energy UK for their input and support.
[2] RenewableUK / OWIC "OFTO Review" submission to the offshore wind sector deal development, 2018.

delivering 40GW by 2030 as an essential part of this ambition, as set out in the Government's manifesto.

0.4. Changes to the regime will also take time to bring about. There is a risk that this will lead to project delays, with the potential for a hiatus in deployment as we transition from one regime to another. This must be avoided at all costs. First, it will delay deployment and put our 2030 and longer-term targets at risk; second, it will undermine confidence in the most successful offshore wind market in the world; third, it will drive up risks and costs (for example though ongoing lease and option fees), which will ultimately be passed on to consumers.

0.5. The success of the offshore wind sector to date has, in part, been built on a clear and stable regulatory regime where offshore wind developers are able to identify and manage risk clearly, including the design, optimisation and build out of offshore transmission connections. The purpose of this consultation is to prepare the ground for a new, enduring regime for offshore transmission. During this transitional process, we should not lose the strengths of the current regime, before a new one is in place.

Building skills and competencies

0.6. The consultation proposes that new actors may need to come forward to design and build coordinated or integrated offshore transmission assets. To date, this work has exclusively been done by offshore wind developers. For projects to be delivered by 2030, via a continuous and steady pipeline needed to support and develop the local supply chain, the early design work will need to be undertaken, at the latest, within the next 3 years, and construction in the second half of this decade. The UK does not currently have a full range of companies that would be able to deliver this work: for example, the necessary supply chain that may be needed to deliver a Detailed Network Design, and then build it. In developing the Pathways to 2030, we need to be sure that the solution can be delivered by parties with the right skills and experience to command the confidence of the development community and, crucially, be delivered without creating delays. Given the volume offshore wind and the associated offshore transmission assets required to deliver it, there is an opportunity for UK leadership in emerging technologies such as HVDC as well as offshore hydrogen electrolysis and floating offshore wind.

A public generation map

0.7. We are concerned that Ofgem is not seeking views on the generation map or the Terms of Reference for the Central Design Group. Both will be central to the successful delivery of a more coordinated, economic and efficient network. In particular, developers and the wider industry hold a wealth of information and data that could be highly beneficial to a high-quality generation map. A lack of consultation of this important part of the process potentially leaves decisions based on these documents open to challenge. In contrast – the prevailing onshore system design processes are subject to open governance and the NOA is subject to annual methodology consultations; in future the development of an HND should be built into the annual network design decision-making processes which includes NOA and ETYS.

Aligned incentives for all parties

0.8. We are concerned that the objectives for the Early Opportunities and Pathways to 2030 elements of the OTNR are inconsistent with the incentives placed upon Generators for early delivery of projects. Specifically, the TCE Round 4 and CES

ScotWind options for lease heavily incentivise early delivery (not least through the requirement to commit very significant sums of money up front), and CfD contracts penalise late delivery (late delivery can potentially lead to termination). Imposition of costs through these incentive frameworks will ultimately place additional burdens on consumers. It is therefore essential that the impact of these incentives are considered in parallel with the OTNR processes and steps are taken by the Government to ensure that the objectives of all aspects of its offshore wind programme are consistent; i.e. timely delivery of projects. Where necessary action should be taken to mitigate any increase in risks facing generators and to avoid introduction of additional costs that will ultimately fall on consumers.

0.9. Furthermore, it is important that the system for sharing of AI between developers and consumers helps promote Early Opportunities projects. The system must take into account that projects that will connect later in time to a shared offshore transmission asset will not be able to commit to substantial levels of AI before the project has received a CfD and has made a final investment decision. The consequence is that AI needs to be underwritten by the consumer and socialized until the later project starts generating. This is not unreasonable given that the consumer will benefit from shared infrastructure through less impact on local communities, less environmental impact and lower system costs. The system for AI also needs to include a gateway assessment process before the relevant CfD allocation round. This is necessary to reduce risk for investors as it is too late that this is assessed and approved at OFTO transfer stage.

<u>*Consenting process and issues*</u>

0.10. Whilst it is accepted that the majority of this consultation has a focus on connection issues and the mechanics of the grid regime, it is essential that the context of planning and environmental consents are considered fully and considered throughout. The fundamental lead time for offshore planning consents together with the assessments which precede an application have the potential to be materially impacted by any significant changes which occur over the course of that window.

0.11. Developers have so far taken responsibility for the consenting processes for offshore transmission connections, together with any onshore components. This has served to minimise risks and uncertainties for the development community but has also resulted in increasingly effective examples of co-ordination, between projects or between specific phases of projects, a situation which will only continue to improve. Reform of the offshore regime must not lose these benefits.

0.12. Any proposed move away from developer-led consent, via an early OFTO for example, would be a significant change, that will need to be carefully and appropriately managed in order to ensure that developers can maintain confidence in the system, are not exposed to significant delay, redesign or challenge and are ultimately supported to deliver the essential pipeline of renewable projects required to facilitate a steady pipeline of known projects for 40GW by 2030, and the longer-term contribution to net zero targets.

0.13. The risk that fundamental change to grid design, after the event, would pose to project development and consent should not therefore be underestimated or oversimplified and should form a material consideration within the consultation. The choices made by developers and promoters in relation to connections, both in terms of technology and in terms of physical location or corridor are closely linked to the overall consenting process. Restricting the choices that can be made in relation to the infrastructure required to serve a given project may have the unintended consequence of increasing the length or scale of development, placing additional burdens on the environment (at a local or national level) and will potentially lead to greater impacts upon communities. All of which would need to be mitigated by developers.

0.14. For the pathfinder projects, where shared connections require new cable corridors, these will require new consents, which may have already been received as part of the wider project. Unpacking that consent, and ultimately resubmitting would be a long, costly, inefficient process, that can take many years to complete. Such a scenario would undoubtedly have a significant impact on our ability to deliver on net zero.

0.15. As the prospect of increased co-ordination is explored by the review it is important to ensure that stakeholders and regulatory bodies are collectively focussed on the current arrangements and their limitations, it is of concern that specific demands surrounding co-ordinated activities which simply cannot be facilitated may be placed on developers unduly or at an unreasonably advanced stage in comparison to the outputs of this review. Developers are keen to see a co-ordinated approach to the design of transmission infrastructure, however equally keen to see a co-ordinated approach to the process of delivering it.

0.16. Finally, Ofgem and BEIS should bear in mind that consenting and planning regimes vary across the UK and a “one size fits all” may not be possible for all solutions, but the final rather will need to take into account national variations in planning and consenting policy.

Early Opportunities questions

1. Question 1: Are there any concepts we have not identified developers may wish to progress?

1.1. As it is our understanding that the concepts have been provided by developers with interests in pursuing them, the six options should be appropriate. Other developers may choose to bring forward other concepts but that is their choice according to the opt-in approach being taken. Ofgem should not rule out other ideas if these come forward during the engagement processes.

1.2. The following points on the six concepts identified are noteworthy and may be helpful in understanding how the options can be flexed and extended, and, how any code changes may need to be framed to ensure they can be carried into the Pathways to 2030 work and the Enduring Regime.

- For all options, assets shown in green as generator assets could be offshore transmission depending on the designs used. For example, option 1 considers two generators connecting at a common offshore transmission substation and sharing an offshore transmission circuit to shore. Either, or both, generator connections to the common offshore substation could be via an offshore transmission link with a further offshore transmission substation at the actual generation project location.
- For all options, where a single generator is shown, there could be multiple generators sharing the offshore transmission works. This could be similar with other assets such as interconnectors or energy storage.
- For all options, there is a level of detail below the schematic diagrams shown which will affect how the options sit within the existing codes. For example, offshore transmission circuits could be HVAC or HVDC, single or multiple circuit, and there could be capacity sharing where the sum of the generation connected exceeds the offshore transmission capacity.
- The options only cover electrical coordination where there is electrical connection and sharing. The options do not consider physical coordination where for example onshore cable routes could be shared but cable assets be entirely separate, or onshore substation sites be shared but substation assets separate.
- Bootstrap options should consider the flows of power, as well as the size. There could be wider benefits to developing bootstraps, such as managing network outages elsewhere. This should be considered in the plan.
- There are other concepts but if not brought forward as Early Opportunities projects, they will need to be considered as part of the Pathways to 2030 and Enduring Regime.

1.3. As noted in the consultation, the Early Opportunities projects are in-flight projects that rapidly need comfort from Ofgem to proceed and that will ideally only require minor Code changes. It is worth noting that the changes required for some of the options, particularly code changes, will be very far reaching, and will probably prevent these options proceeding in the near term. Furthermore, these concepts are a significant divergence from the existing grid connection agreements and DCO approvals. Opening these up for review may delay project timelines, and this must be avoided if we are to meet the 2030 targets via a steady pipeline of deployment. This is why a key point about this workstream is that it should be on an “opt in” basis for developers.

1.4. Ofgem should also recognise that some developments are already bringing forward shared infrastructure within a zone, for example shared cable routes or collocated landing points. These projects should also be considered alongside the OTNR options outlined in the consultation as these designs reduce the impact on local communities especially where one project is taking forward shared common infrastructure.

1.5. Throughout we would like to highlight the difference between “coordination” and “integration”. The consultation uses these terms interchangeably, but industry recognizes a distinction between these concepts:

- *Coordination* does not have electrical sharing and has already been demonstrated at Sofia and Dogger Bank wind farms (RWE and SSE) and Vattenfall’s Norfolk Zone.
- *Integration* implies some form of electrical sharing. This poses more commercial risks, which are not addressed in this consultation. Coordination can be delivered within the current framework where projects are sufficiently geographically close together – and delivers many of the environmental, social and economic benefits that the OTNR aims to achieve, but integration will be more challenging if commercial risks are not addressed.

2. Question 2: Should anticipatory investment risk be shared with consumers? If it should, what level of risk is it appropriate for consumers to bear?

2.1. Yes, we agree that anticipatory risk must be shared with consumers, as consumers will be the primary beneficiaries of shared connections through lower capital costs and the reduction society and environmental impacts. As noted within the consultation there are almost no examples of anticipatory investment being undertaken within the existing framework where the risk is almost entirely left with the generator. This current framework disincentivises generators from participating in anticipatory investment and is therefore not suitable in meeting the four policy assessment criteria or in meeting the interests of consumers in the longer term.

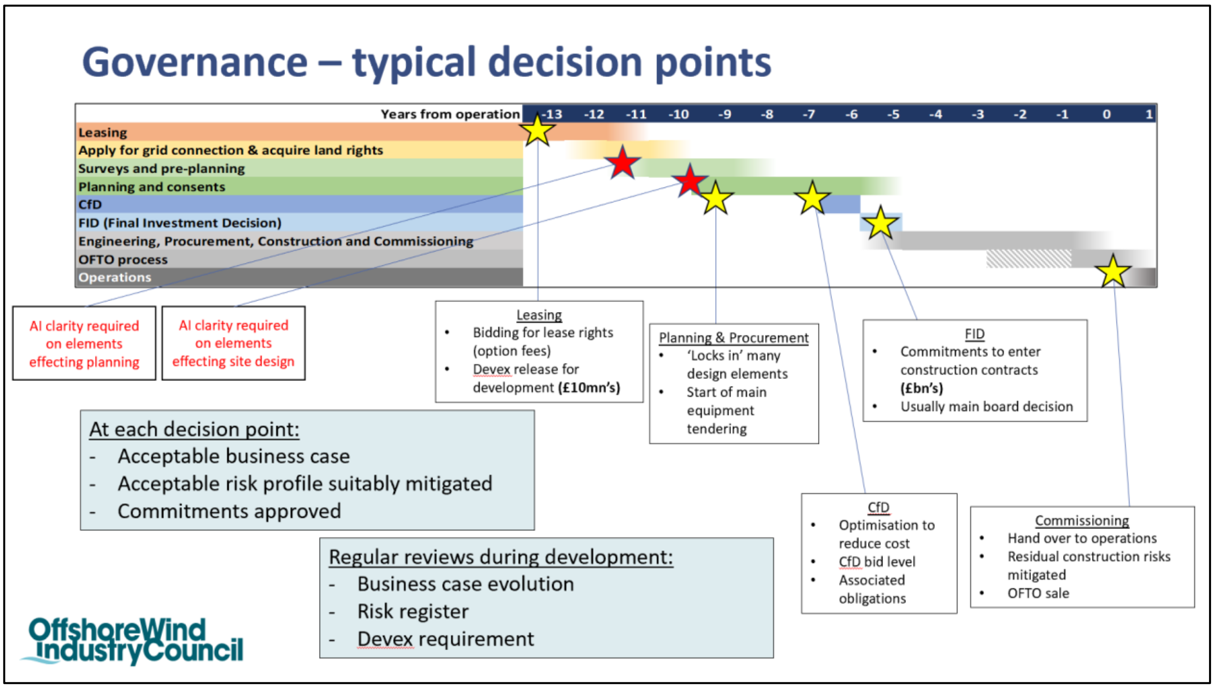
2.2. We note Ofgem’s view that, “AI risk should be allocated to those best placed to manage it’, however we also believe that the cost-benefit of AI should also be aligned to those who benefit from the investment. For example, if a second project or the consumer is benefitting from AI (due to lower infrastructure costs or reduced environmental impact) we believe that the cost of this AI should be allocated to the second project and the consumer via risk-sharing mechanisms, even if the first project may be better placed to manage the cost and risk, for example if the first project is constructing the assets. The benefits of the AI will therefore be shared between the developers and the consumer due to overall lower cost and/or environmental, socioeconomic impacts. However, this also needs to take into account a later project’s limited ability to commit to substantial levels of AI prior to the award of a CfD, as noted in paragraph 0.9.

2.3. We agree that risk should be shared between consumers and generators (and other users of the transmission system). The level of risk consumers should bear should be carefully considered, such that it ultimately delivers offshore transmission and generation projects in their interests and as a consequence, meets the policy assessment criteria of Appendix 3. This does not necessarily mean “the minimum required to secure AI investment by developers” as suggested in Section 2.42 of the consultation.

2.4. Overall, we believe that:

- A greater use of anticipatory investment is absolutely necessary to deliver a more coordinated grid and without the wider use of AI coordination will be extremely challenging. We believe that Ofgem need to stimulate this AI early in the process so early strategic decisions can be taken by developers.
- We believe that a risk model needs to be developed that is fair and doesn't compromise competition in the Contracts for Difference (CfD) auction, if projects take different development routes. Projects that are able to coordinate or integrate connections should not be placed at a disadvantage to radially connected projects in the CfD process.
- There cannot be excessive interdependence between coordinated projects: i.e. the timely and successful delivery of one project cannot be dependent on the success of another developer (e.g. in the same or later CfD rounds).
- For projects that require anticipatory investment decisions early in the process, in particular where these are required for the planning process, Ofgem could consider a gateway AI process that allows for early-stage project development to go ahead; see decision points below.
- And lastly, Ofgem may need to socialise AI elements for the first project when a subsequent project could be developed on a different timeframe (highly anticipatory investment).

2.5. We further consider that it is likely the consumer risk will vary between concepts and the details of concepts and that the system put in place will need to tolerate this variance, noting that all anticipatory investments should go through an Ofgem assessment and approval process (so there can be a cap and/or other safeguards put in place to manage risk).



3. Question 3: For concepts that intended to provide a wider system benefit, e.g. by mitigating an onshore constraint, how should the need for investment be demonstrated by the developer?

3.1. RenewableUK agrees with the principles that in assessing anticipatory investment for approval, Ofgem will need to see evidence that it is worthwhile and ultimately delivers on the objectives in achieving net zero. Some concepts deliver a reduction in the amount of offshore transmission and should be relatively straightforward to assess, the main issue being whether the risk level is acceptable to the consumer and the developer having full confidence in Ofgem's cost assessment process to recover full costs.

3.2. Projects that are to provide a wider system benefit should be cost benefit assessed by NGESO to show that the proposals are worthwhile, and Ofgem will need to sign this off. This will require some input on costs from the offshore generators and should make comparison to other options available to NGESO, to provide the wider system benefit and must take into account factors that are not purely cost related such as consenting issues and deliverability.

3.3. NGESO, the transmission owners (TOs) and Ofgem already have a wealth of experience in such matters, but development and submission of needs cases and subsequent decision (approval, or refusal, as appropriate) can take a long time. We are concerned that the urgency attached to the Early Opportunities' projects is not yet fully recognised, and we suggest a clear timetable for this approval process be established with the clear aim of delivering 40GW by 2030, via a steady pipeline through the latter 2020s. Furthermore, it may be the case that some TOs may take forward some of these concepts in the HVDC bootstraps on the east coast, for example.

3.4. If this approach were to be taken forward, we note that a clear process should be established providing the developer, the ESO and regulator with clear and timely decisions that could allow project progression.

4. Question 4: What options are available to developers in demonstrating a reasonable expectation they intend to connect to the system?

4.1. We would reiterate that the 40GW by 2030 target must be met; delays to this target will undermine the further development and maintenance of the UK supply chain. With the supply chain in mind, we cannot seek to deliver everything in 2029 and 2030. A steady delivery of the 40GW target must materialize throughout the 2020s. We note that for the Early Opportunities workstream, targeting projects aiming for CfD allocation round 5 and 6, projects should already be known and at a significantly advanced development stage. It is likely that projects would have some level of permitting in place, or possibly grid agreements. These all require financial commitments from developers. As projects progress through the development process, the developer's ability increases to demonstrate a reasonable expectation to connect by a specific date (the connection date is fixed in the connection agreement, which is signed very early in the process). Conversely, as projects progress their ability to change arrangements decreases. Therefore, a balance must be found, and the current approach whereby projects are deemed to have demonstrated commitment to connect only when they have secured a CfD cannot persist. It is at odds with the drive for increased coordination/integration in on and offshore transmission infrastructure design.

4.2. Specifically:

- Projects intending to connect to the system should have a connection agreement with NGESO. A connection agreement with NGESO will require User Commitment (demonstrating a financial commitment) as well as a clearly set-out programme and connection date.
- Projects due to connect in the mid-2020s are likely to well-advanced, possibly with planning decisions approved or due to be decided in the coming months. Projects with consent would potentially leave little room to change from the consented arrangement.
- Projects without planning may have an Agreement for Lease, or be committed to signing this soon, which may attract substantial financial commitment.
- Projects onshore are more difficult to assess and could initially be taken on a case-by-case basis, but as above, a land lease and a connection agreement could be required.

4.3. Having said that, for the Early Opportunities workstream project shareholders will not pursue options which negatively impact project programmes for connection by 2030, or which risk generating excessive project DEVEX costs which are not recoverable. The Government may need to provide some comfort that these costs may be compensated to incentivise these options.

4.4. In terms of signals, project developers investing in the development of a number of potential connection options simultaneously, with no idea whether regulatory or code changes will be made to enable the concepts, is a strong signal that these projects are progressing and want certainty prior to DCO submission. This could be taken into account.

4.5. A straightforward way to minimize the excess DEVEX as soon as is possible would be for the TOs to be extremely proactive in issuing Agreement to Vary documentation if the relevant developers are amendable to this approach (on an opt-in basis). It should not be left to developers to drive this – indeed, they cannot do so. If the same connection date can be achieved for an offshore wind farm by connection, for example, into a bootstrap that option should be offered now. This applies less to MPI connections, for which the market design implications across borders is unclear and could result in risking projects' success.

4.6. In circumstances where higher user commitments may be required by the ESO (for example more TEC to accommodate multiple projects) it is unclear which project owns the TEC and how user commitments would be allocated across the zone; where a single developer is taking all projects forward this element is less problematic

5. Question 5: To what extent do you agree with our proposals to remove barriers to the Early Opportunities concepts? Please explain your answer.

5.1. RenewableUK agrees with some of the principles and proposals, but not all. In addition, there is a need to work up the proposals with more clarity and detail before they can be taken forward with code changes and similar. Our considerations are set out below.

Assessment and approval by Ofgem

5.2. Anticipatory investments need to be assessed and approved by Ofgem ahead of OFTO transfer processes and cost assessment. This must cover all types of anticipatory investment. Ofgem should provide those undertaking anticipatory investment with up to two assessments and one of these will need to be at early stages of projects. Each assessment should result in an approval to proceed with the anticipatory investment (if deemed appropriate), implying that it will not be a disallowed cost at cost assessment. Ofgem may wish to frame these as Gateway Assessments. If Ofgem does not provide these assessments and approvals, then those considering undertaking anticipatory investment will not proceed and we shall be left with an uncoordinated situation as we find ourselves in today. For projects considering a shared infrastructure this Gateway Assessment needs to approve principles for any anticipatory investments before the relevant CfD allocation round. This is necessary to reduce risk for investors as it is too late for this to be assessed and approved at OFTO transfer stage.

5.3. Assessment and approval by Ofgem should consider the benefits of the anticipatory investment, e.g. ultimate cost savings; reduction in infrastructure and environmental and societal impacts etc against the risk; risk being judged on the expectation of all connectees delivering; and, the ultimate exposure of the consumer. Assessments will need the support of NGESO and this could be an agreement that the anticipatory investment is appropriate, economic and efficient, or, a more detailed cost benefit analysis as might be required for a quasi-bootstrap or bootstrap concept.

5.4. Cost assessment should still seek to ensure that approved anticipatory investments have been delivered in an economic and efficient manner. Unapproved anticipatory investment would be expected to be disallowed, however, could be readmitted, potentially at a later date, should the situation change, e.g. the anticipatory investment was deemed too risky but that risk did not crystallize.

5.5. We note that Ofgem have included “Annex 1 Treatment of AI in Early Opportunities concepts” in the consultation and this provides useful information for developer. However, we would welcome more information on the proposed calculation and methodology to determine how “AI risk is shared between subsequent project(s) and consumers in proportion to the potential benefit the developer(s) of the subsequent project(s) expect to derive from their project(s).” We believe that calculating the developer and consumer benefit could be subjective and that the proposed “desirable features of charging arrangements” could lead to an increased risk profile for developers if the only consumer element derived by Ofgem’s apparent interpretation of “clear system benefit” is boundary relief. We believe that, to incentivise Early Opportunities coordination, a broader assessment of the consumer benefits would be required. The OTNR’s objectives are to find “the appropriate balance between environmental, social and economic costs”.

5.6. However, Appendix 1 focusses purely on the economics. It is reasonable that, where benefits are purely accrued by the consumer, this is reflected in cost recovery. We note that recovery of the consumer AI element through a TNUoS benefit only seems to apply to the MPI solutions. We would welcome more clarity on the recovery of consumer AI for the non-MPI concepts.

5.7. We believe that the “user commitment” element of cost recovery may need further consideration. Firstly, there could be a significant cashflow impact for developer 1 if they are taking forward development and construction work for developer 2, and then reimbursed later in the process. Secondly, there could be significant pre-FID commitments for developer 2 if the conclusion of the OFTO tender process is prior to the project 2 FID, or even CfD award.

CfD and competition issues

5.8. The current CfD rules have brought forward world-leading levels of investment in offshore wind, at incredibly low costs to the consumer. However, by design they ensure that all individual offshore wind projects are in competition with one another.

5.9. As noted within the consultation, the current CfD processes put competitive pressures on generation projects and create issues for coordination. There will still be projects where a radial connection is the only option (due to a lack of proximity to other projects, for example) or circumstances where commercial considerations may make coordination impossible. However, where coordination is being taken forward, developers will still be reliant on other projects being successful in their CfD bids. Furthermore, coordination will require detailed design of network assets, which are reliant on individual project specifications. BEIS and Ofgem need to consider how these specifications can be shared, without influencing competitors bidding strategies.

5.10. Even if risk sharing between coordinating/integrating developers is resolved to enable this to be commonly investible, the CfD bid dependency will be an issue that must be resolved. Two coordinating projects enter the CfD auction in round AR-X, but only one project wins a contract, then the delivery plan upon which the bids were built doesn’t hold. The first developer’s project is also not “terminated” at this point and so user commitment payments would not be needed – the project may choose to amend its connection agreement, and bid and win in AR-Y. Therefore, contingencies may be needed to be developed (an entirely new process to that which is done today).

5.11. Finding solutions to these issues, whilst broadly retaining the current CfD design, is essential to creating an investible framework for developer-led integration at lowest cost to the consumer. OWIC wrote to BEIS and Ofgem in November 2020 to highlight these commercial risks.

Transfer of funds at OFTO tender process completion

5.12. Whilst we agree that risk and cost should be appropriately shared with the consumer in taking anticipatory investments forward, we are concerned over the cost reimbursement process identified in Section 2.40 – 2.41 and illustrated in Figure 10 of the consultation. This process will require new regulations and is quite different to current arrangements. For example, generator commissioning requirements could require careful consideration across coordinated projects that are delivered in stages, considering commissioning of subsequent connectees may be beyond a 24-month generator commissioning timescale of the first connectee.

5.13. Under the current regulations, a developer who has transferred offshore transmission assets to an OFTO is reimbursed the Final Transfer Value by the OFTO alone. Transmission Use of System charges are then levied by NGESO to recover the transmission costs, these being partly made up of sums from the relevant and newly connected offshore generator(s) and also from other users of the transmission system (effectively the consumer). NGESO then allocates the correct sums to the OFTO and other transmission owners.

5.14. Ofgem's proposals appear to show the payment of the Final Transfer Value (to 'Developer 1') including as OFTO payment, plus the transfer of User Commitment sums (underwriting sums) from 'Developer 2' (understood to be a connectee at some stage to the new offshore transmission) to 'Developer 1', plus payments to 'Developer 1' (who has just transferred asset to the OFTO) from Transmission Use of System charges. There is no arrangement currently whereby Transmission Use of System charges are collected and allocated to a Developer (Generator). Additionally, User Commitment is lodged by developers (in this case Developer 2), but these sums are only collected should the developer terminate its agreements to connect. In such a case, NGESO collects the sums and uses them as cover for stranding. There is no arrangement whereby User Commitment sums are used to make payments to other generators.

5.15. We believe the arrangements as set out are inappropriate and would in any case require significant change. This will not allow delivery of the Early Opportunities' projects. However, we consider that Ofgem has identified the key mechanisms of financial cover and payment for transmission works, be they anticipatory or not. We further believe the existing mechanisms of User Commitment and Transmission Use of System charging can be used to achieve the desired outcomes of the Early Opportunities' projects with (generally) only small amendments. We further outline this below.

How the financial cover for anticipatory investments can work

5.16. Generators (or other parties) build anticipatory investments as part of the offshore transmission works and receive the full Final Transfer Value from the appointed OFTO as per normal.

5.17. Existing User Commitment arrangements are used to provide cover before other generators connect. This will need the existing User Commitment arrangements to be extended to cover Generator Build scenarios. To date this has not been done, as all offshore transmission has been delivered by a generator who is the sole user, i.e. it has been pointless to ask a generator to provide cover against their own works and costs.

5.18. The existing User Commitment arrangements require parties seeking connection to the transmission system to provide financial cover for the key works being undertaken to connect them as far the nearest existing MITS node. The cover is based on the parties' share of the cost of the works according to its TEC (MW capacity) versus the (MW) capacity of the works. A factor is applied to reflect the ability of assets to be used elsewhere if ultimately not needed as planned, and a factor is applied to reflect strategic decisions by NGESO in regard the works. To date this strategic factor (distance factor) has been used to decrement cost where NGESO has made a strategic choice which results in more cost than the connectee would otherwise have been exposed to – this factor could be adapted for strategic choices in coordinated networks and to reflect a level of consumer cover. These User Commitment sums only crystallize should the generator terminate its grid connection agreements (not proceed), in which case the sums are taken by NGESO to provide cover against stranding.

5.19. It should be noted that in some cases the sums may not provide a low level of cover, e.g. when second project connection dates lag four years or more behind the delivery of the offshore transmission works. These cases will need to have been carefully considered during anticipatory investment assessment and approval. These cases may either require increased consumer risk and/or other mitigating measures. Other mitigating measures could include clear decision milestones allowing the anticipatory investment to be dropped or the design to provide for later additional work when later connectees are ready. As noted above, such considerations need to take into account that a later project is not in a position to commit to substantial levels of AI ahead of the certainty of a CfD and having passed FID.

5.20. Once the offshore transmission works are operational, the existing Transmission Use of System charging arrangements are used by NGESO to recover costs for payment to the OFTO. As noted within the consultation this currently implies around 20% of the cost of offshore transmission is recovered from consumers. In the case of stranded assets, then cover would be obtained from the User Commitment arrangements with any shortfall being picked up through the Wider Transmission Use of System charges. As the connected generator would pay Wider Transmission Use of System charges based on its share of the costs, any shortfall would effectively be covered by charges on other transmission system users (effectively consumers). We consider that the current Wider Transmission Use of System charge arrangements for offshore would mostly need only minor amendments to cover off the Early Opportunities' concepts.

Shared offshore transmission concepts

5.21. This relates particularly to the consultation's concept 1 but also other concepts such as the OFTO led MPI (option 4).

5.22. We welcome the removal of Generator Focused anticipatory investment (GFIA) as set out in Section 2.52 of the consultation and concur that all anticipatory investments should be treated in the same manner.

5.23. As noted in our response to Question 1 of this consultation, all the Early Opportunities' options could involve electrical system integration by generators or other parties albeit this is more likely to be the default in the Pathway to 2030 and Enduring Regime given the Early Opportunities' options are driven by specific real projects that have been under development for a long time.

5.24. We are extremely concerned by the proposals which appear to suggest that much the same as the current approach (through GFAI), all the risk will be placed with the generators (or other connecting parties). This is drawn out by Table 6 of Appendix 1 in the consultation which hints that if Ofgem believe the benefits accrue to the connecting parties then they will take all the risk. This is also suggested by Figure 11 that where Ofgem does not see a system benefit, the expectations are that the developers will take all the risk. If this approach is taken, it can be expected that the sharing will not proceed much as the case today.

5.25. It is important to note that electrically integrated offshore transmission (e.g. as illustrated in Ofgem's concept 1) will not come to bear unless it is incentivised as part of the OTNR policy decisions. This is not to say that coordination of transmission infrastructure without electrical sharing will not bring any benefits (it can and will deliver on the OTNR policy assessment criteria in many cases). Both of these should be objectives for "coordination" as outcomes of the OTNR workstreams, where benefits compared to the counterfactual can be demonstrated.

5.26. A decision to incentivise and promote electrical integration of offshore transmission by generation and other parties (subject to appropriate assessment and approvals) would meet all of the network design criteria of Appendix 2 of this consultation and the OTNR policy assessment criteria, as set out in Appendix 3 of the consultation, namely:

- It is readily deliverable and can significantly contribute to net zero and 2030 targets.
- It aids deployment with no adverse effects on competition and risk can be sensibly apportioned.
- It results in a significantly reduced environmental and societal impact through reducing the amount of offshore transmission infrastructure.
- It results in positive consumer and transmission benefits by reducing offshore transmission costs.

This would therefore be supportive of also meets Ofgem's legal duties aims to act in the consumers' best interests of current and future consumers.

5.27. Sharing of offshore transmission infrastructure by generators and other parties may in some cases result in (economic) benefits to the generators, but in others may not. However, this should not be a focus of the assessment by Ofgem because irrespective of this, sharing of offshore transmission will invariably be of benefit to the consumer both economically and with wider objectives in mind. It is therefore essential that both coordinated and electrically integrated offshore transmission concepts are incentivised (especially in cases where there is a cost to generators) along with other concepts through assessment and approvals from Ofgem and sharing of risk with consumers, so as to deliver the best outcome of the OTNR. Without this, we believe that coordination will be significantly hampered and reduced.

<u>Focus on generator benefits in relation to risk apportionment</u>

5.28. In several parts of the main text and in Appendix 1 of the consultation, Ofgem makes it clear that in assessing which parties take the risk with anticipatory investments, it will assess the benefit the generators may realise from the anticipatory investment in apportioning risk. In simple terms we expect that this approach will act to disincentivise coordination as generators will effectively be asked to take the risk and pay for the potential benefits they might see. This is essentially taking the same approach as present which to date has led to hardly any coordination, and no integration across different developers that OWIC/RUK is aware of.

5.29. As noted above, this detracts from the consumer benefit that follows. Therefore, attributing these risks/benefits solely to developers should not be a focus of the assessment by Ofgem because coordination of offshore transmission will, subject to appropriate assessment and approval, invariably be of benefit to the consumer both economically and with the wider OTNR policy objectives in mind. The focus should not therefore be centred around what benefit a generator may or may not see, but whether the proposed anticipatory investment will deliver on the OTNR objectives put in place, ultimately to assist in achieving net zero in the most economic and efficient manner, delivering benefits to current and future GB consumers.

5.30. Further to the above, Ofgem makes it clear in Figure 11 that where it does not see a system benefit, the expectations are that the developers will take all the risk. We understand 'system benefit' in this context to mean some form of wider transmission system benefit such as boundary relief. This would mean that Ofgem's expectations are that for most of the Early Opportunities' concepts, the risk will wholly be with the developers. If this is how system benefit is defined, then we do not agree with this approach. Such an approach also does not assign any consumer value to environmental or local community benefits, which is not aligned with the aims of Early Opportunities workstream or the objectives of the OTNR.

5.31. Where the Early Opportunities' concepts meet the network design criteria of Appendix 2 of this consultation and the OTNR policy assessment criteria, as set out in Appendix 3 of the consultation, they will be in the consumers' best interests and should be incentivised through sharing of risk. This is certainly the case for some of the concepts where the overall amount of offshore transmission infrastructure is reduced through sharing, and hence costs to the consumer are reduced along with environmental and societal impacts. Other concepts will need assessment by Ofgem as discussed to ensure they are delivering a wider benefit in the terms of the aims and objectives set out.

Level playing field

5.32. In several places, e.g. Figure 11 item 3, Ofgem sets out its intentions to create a level playing field. In the terms of the OTNR and aiming for net zero, we believe this is reasonable. The treatment of TNUoS costs for the Generator in an interconnector led MPI concept are unclear in table 1. We would welcome more detail from Ofgem on this element and would be interested to understand how a level playing field can be maintained across the different MPI solutions, especially where developers may be competing against each other for a CfD.

Consenting issues

5.33. For the pathfinder projects, where shared connections require new cable corridors, these will require new consents, which may have already been received as part of the wider project. Unpacking that consent, and ultimately resubmitting would be a long, costly, inefficient process, that can take many years to complete. Such a scenario would undoubtedly have a significant impact on our ability to deliver on net zero.

Question 6:

6. Do you believe a Significant Code Review is required to give effect to a potential decision to 'share' AI risk between consumers and developers?

6.1. We do not believe a Significant Code Review is required, and would take too long to complete. We have outlined what we believe is the best way to implement the necessary changes through the existing codes. Given the importance placed on this reform by BEIS and Ofgem, these code change should not simply be left to developers to progress; both Ofgem and the ESO need to take a bigger role in driving the required code changes there should be dedicated resource within the ESO to support and fast track the necessary code changes (see paragraph 7.5 below), and support their implementation among developers. We recommend Ofgem direct the

ESO to lead this work, to deliver the necessary code changes within the necessary time frame.

7. Question 7: Do you agree with Ofgem's proposed approach to deliver the objectives of Early Opportunities workstream?

7.1. Please see also the response to Question 5 of the consultation. Our response to this question relates to the process of delivering the necessary changes.

7.2. We welcome Ofgem's proposal to "intend to make a decision on proposals this year" and "then consult stakeholders on the changes required to the framework that will facilitate implementation, for example licence conditions and Cost Assessment Guidance" (paragraph 2.82). As highlighted above timing of AI sign off, timeliness of charging and code modifications, and licencing and tender amendments or derogations will be key to delivery of the Early Opportunities workstream.

7.3. We note that the projects under consideration are likely to be entering CfD Allocation Rounds 5 and 6, therefore project development and key decision points will continue in parallel to OTNR activity. We believe that, alongside a clear commercial case to trigger delivery, Early Opportunities concepts require clear regulatory guidance and early barrier removal. Ideally, Ofgem should aim to consult on the final models as soon as possible, with a clear timeline for implementation. We also believe that risk analysis should be published alongside the final proposals.

Cost assessment guidance and processes

7.4. We agree with Ofgem's proposals to update the cost assessment guidance (and process) for anticipatory investment related to offshore transmission as noted in Section 2.51 and 2.52 of the consultation. We also agree with Ofgem's proposals to update the cost assessment guidance (and process) for interconnectors in so far as this needs change as noted in Section 2.54 of the consultation.

Charging and User Commitment (underwriting)

7.5. In relation to the CUSC and in particular User Commitment and Use of System charging, we believe that only minor amendments need be made. However, we are concerned that following the normal processes, with an expectation that individual parties and NGESO will bring forward individual and sperate modifications, will take too long. Therefore, we suggest that Ofgem directs NGESO to create a dedicated team which will examine the concepts with developers, possibly via a Task Force style approach that was used for BSUoS reforms recently, and bring forward CUSC modifications, which are then fast tracked. This approach could implement changes within a 12-month timeframe.

Grid Code and SQSS

7.6. Changes to other codes may be more difficult to understand and to bring forward in short timescales. We therefore believe that some derogations are likely to be necessary. This is particularly the case with the Grid Code which is already overly complex. In relation to the SQSS, this needs review and a level of wholesale change in relation to offshore wind and offshore transmission, therefore derogations against the existing SQSS are likely to be necessary, at least as a holding position. Developers will need a dedicated resource from NGESO to understand the key issues in these codes and decide on how best to overcome them.

Other Codes

7.7. It is not clear whether other codes may be affected, notably the STC and BSC. This will need to be assessed also with NGESO and a best route forward developed. Again, this may require derogations.

Pathway to 2030 questions

8. Question 8: We consider that a holistic design will result in a more coordinated, economic and efficient network. Do you agree? Please give reasons for your answer.

8.1. Yes, if executed properly, the holistic network design (HND) can support the delivery of a more coordinated and efficient network through identifying wider network needs, opportunities for both coordinated and electrically integrated connections. We agree with Ofgem's view that, "all network infrastructure (both onshore and offshore) which is necessary to connect projects in scope of this workstream is designed in a coordinated manner with an optimum engineering solution" and believe that a holistic view is essential to delivering an efficient offshore grid at speed.

8.2. However, we question whether an HND will always drive the more economic and efficient outcome, as this depends on whether an HND can be delivered in practise and whether a design fits with the timescale of individual projects. If the HND process delays the delivery of 40GW of offshore wind by 2030 (which requires 2-3 GW deployment each year in the 2020s) or leads to a network design that cannot be delivered this may not be an economic and efficient approach.

8.3. The current system incentivises offshore wind developers to build the most economic and efficient grid connection within the scope of the regulatory environment. Under this process the developer has to consent, design and integrate a grid connection that allows the windfarm to function in the most efficient and innovative way. The developer carries the vast majority of the risk of costs of the grid connection prior to OFTO transfer (although costs which Ofgem deem inefficient cannot be recovered), and most importantly the grid connection is required for windfarm to earn revenue and recover costs. This means the developer has to balance these competing factors to deliver a connection that is the most economic and efficient for their windfarm. If these elements are broken up, and the correct incentives are not in place, it may be the case that parties are only incentivised to deliver their elements effectively. This could mean an HND that does not appreciate the cost to the project of delivery, cannot be consented or does not utilise the most innovate technology. This is not just a concern for the HND but for the whole offshore grid delivery value chain.

8.4. We assume that the ESO will lead the development of the HND. This will require input from the TOs, The Crown Estate and the Crown Estate Scotland. On the latter point, we note that the HND may be published before the outcome of the ScotWind Leasing Round. The HND cannot prejudice the outcome of this commercial process, but the two must be aligned. Initial offers to successful bidders are expected in January 2022, but final confirmation may not be expected for a number of months. It follows that the HND must cater for all credible outcomes of ScotWind when it is published so that it does not require substantial re-work when ScotWind is finalised.

8.5. We note that the government is consulting on the future of the ESO, and possible functions include "holistic and coordinated (onshore and offshore) network planning".

We agree that that a potential future System Operator should have this function, but also work closely with TOs and developers on the delivery of the network.

8.6. However, while the design is essential, so too is the delivery. We are concerned that while the ESO holds the necessary skills for design, they are not best placed to fully understand how the network will be built and delivered, which is an essential part of the process to ensure that the necessary network assets are brought forward in the correct order and at the right time. This is because the ESO does not itself have extensive experience of building and delivering offshore networks. In the design of the HND, the ESO must work closely with delivery partners (see below) to ensure that a robust and credible design and delivery plan is produced.

8.7. We would like to set clarity on how the HND will be delivered alongside the Network Options Assessment (NOA), and the production of the HND should not delay the publication of the NOA, which is essential for wider network development. As noted in our introductory comments an updated HND should be integrated within existing NOA/ETYS processes in the longer term to form a holistic approach for an enduring network design and planning regime for future network investments and design.

8.8. Finally, paragraph 3.26 states that "We expect the HND to be delivered according to a robust methodology cognisant of, and consistent with, the requirements of the RIIO processes." These requirements are focussed on the economic costs and benefits of network investment decisions, and currently leave little room for the role of anticipatory investment. Ofgem will need to make clear how they expect anticipatory investment to come forward within the existing RIIO-2 price controls, (and promote such investment). For instance: will re-openers be required? Does the existing RIIO-2 framework (e.g. under LOTI) enable the pace of developments needed? It is essential that the HND is able to take into account long-term network requirements and accept a level of risk on anticipatory investment, including highly anticipatory investment. The Generation Map will assist with this.

8.9. Paragraph 3.5 outlines that Ofgem "envisage[s] the new approach will speed up later development steps, including the consenting process…". This is not within the remit of Ofgem to determine and no evidence has been provided to suggest that this aspiration is realistically achievable. The consultation goes on to say: "while planned reforms may result in delays in the early development steps, we envisage the new approach will speed up later development steps, including the consenting process, thus reducing the overall time for project delivery." As the planning and consenting processes (in England and Wales) are based on Statutory timelines, with a clearly defined process, we would be interested to understand how Ofgem believe the consenting process could be accelerated, reducing the overall time for project delivery.

8.10. This issue is particularly relevant in Scotland, where there is an entirely different consenting regime and, in some instances, far less pressure on coastal land use compared to, for example, East Anglia and Lincolnshire. Development delays represent a significant cost that ultimately gets paid by consumers and will have adverse impacts on the reduction of greenhouse gas emissions. Delivery of the onshore transmission system infrastructure will be the critical path for all Round 4 sites and ScotWind sites that will be delivered before 2030 and therefore any network delivery delays will have a direct knock on to the delivery of 40GW by 2030.

8.11. Furthermore, the CION process is a critical element of the consenting (and compulsory purchase) process, to demonstrate projects are following due process. If the CION is to be replaced by the HND process, this will need to have the same legal force and recognition among relevant stakeholders to avoid undue challenge and delay to network build out.

8.12. We do agree that changes to the current system could lead to delays in the early development steps and could increase uncertainty whilst policies are defined; this risk is increased if the competitive element associated with grid development/operation is applied to the pre-construction process and cannot be run in parallel to the development process. Currently competition is applied after the windfarm asset is generating so the OFTO tender process is not factored into development timelines.

8.13. It is not clear what the remit or authority the central design group has within the context of the other TO/SO licence conditions. For example - will the recommendations from the group give stakeholders sufficient confidence to progress with investment to progress the proposed reinforcements? Will Ofgem seek to approve the outcome of this group in order to provide such confidence?

8.14. Paragraph 3.25 outlines that "a classification decision will have to be made to determine whether to apply to onshore or offshore licencing regime." Who will make this decision and what will the basis of this decision be? When will this decision be made? Without clear delineation of responsibility, there will likely be a high risk of delays.

8.15. Furthermore, we are concerned that the accelerated timeline for the HND will mean that the CDG cannot effectively consult with local communities and industry, as outlined in 3.23. This is a particularly high risk for Scotland where there is much higher uncertainty about the location and size of generation likely coming forward in the Pathways to 2030 timeframes.

8.16. We believe that a 5th Network Design Objective should be included in Table 3: "Efficient delivery of offshore wind projects, ensuring that individual project delivery is not delayed."

8.17. We note that the consultation does not include any questions on the Generation Map, again we believe that developers hold a significant amount of data related to the offshore environment and should be consulted on during the Generation Map processes, especially if the generator map identifies areas of the seabed that are most appropriate for cable corridors or restricts development in certain areas.

8.18. Last, we welcome Ofgem's view that an HND, the NOA and ETYS will be aligned to deliver a holistic approach on and offshore.

9. **Question 9: Do you agree with the planned work for a detailed network design offshore?**
And
Question 10: Who do you believe is best placed to undertake the detailed design for assets that are in offshore waters?

9.1. First, we note that for the Leasing Round 4 projects the early stages of offshore DND have already begun and are being undertaken by the winning developers – in line with the current framework. In the current framework Offshore DND and pre-construction phase works are largely undertaken by developers, as a way of ensuring maximum project optimisation. It is not clear what detailed network design will provide in addition to this work that is already undertaken by developers to ensure project optimisation. Introducing a DND phase may simply delay progress and insert an additional level of analysis that will be repeated at a later date when the delivery body starts its work and detail of the offshore projects connecting are known.

9.2. We are not clear on the concept of Detailed Network Design (DND) that Ofgem has in mind. The HND should deliver a sufficiently functional specification, albeit probably very high level, for delivery parties to move forward. We do not believe there is a need for a separate DND at this point in time and consider that the development of a DND will create an unnecessary delay whilst it is worked up. The following points are noteworthy.

- Given a high-level functional design from the HND, a delivery party's next steps will be to consider the design options that meet the HND and develop them at a relatively high level so as to provide a platform from which to progress the consenting.
- Design is generally developed throughout the consenting process and only finalised with a detailed design at point of construction.
- An overly detailed design (e.g. DND) post HND and pre-consents will be inappropriate. It will not (generally) allow for changes which are quite possible during the overall delivery process due to changing requirements and technology options.
- An up-front attempt at DND will probably involve a delay of around 6 months. We have around 9 years to deliver on 2030 targets. Six months would be an immediate and unnecessary delay of 5% of the available time; a year delay would add an additional year of option fee payments for leases.
- A DND is useful for tendering. The only tendering in the delivery models (other than to the end contractors on the ground) is to appoint an OFTO and this is only relevant in models where an OFTO is entering earlier than operation.
- The onshore TOs are going to be very busy delivering the onshore reinforcements and placing the burden of responsibility on these parties too will likely slow down development, rather than speed it up.

9.3. There could be some merit in a detailed network design, if brought in at the correct stage of relevant delivery models (see below). We believe a party that has experience of both grid management and the marine environment would be best placed to undertake a DND offshore. The DND should be carried out by organisations with a track record of operating offshore, with relevant technical capability and a strong understanding of offshore technology.

9.4. The DND needs to include the specific technical requirements of connecting the offshore windfarms, which may not be available at an early stage. As highlighted in the HND section, the party that delivers an DND needs to be correctly incentivised to deliver the most optimal design, balancing technology maturity, planning risk, cost reduction and environmental constraints.

11. Question 11: Do you agree that the existing developer led model should be retained and applied where the HND indicates a radial solution should be used? Please explain your answer.

11.1. Yes. We agree that the existing developer led model should be retained for radial solutions and for offshore zones where one developer is delivering the whole project portfolio. However, the developer(s) should retain an option to not proceed with Generator Build as per the existing regime. In the existing regime, a developer can elect for Generator Build or an OFTO model and this is established at the time of applying for and signing connection agreements with NGESO, i.e. if an OFTO model is used then it would be a (very) early OFTO model. Section 3.35 of the consultation recognises this and suggests this is the preferred way forward which we agree with. We recognise that any option to not take offshore transmission forward under Generator Build may not necessarily mean it will be initially taken on by an OFTO and this should be recognised in setting out the options.

11.2. This option could include a clear decision point for a developer led vs third party approach, and greater coordination would still be driven by the HND

11.3. As noted in paragraph 8.3, we believe that there are currently clear incentives in place for the developer to deliver economic and efficient offshore connections. Under the current process the developer has to consent, design and integrate a grid connection that allows the windfarm to function in the most efficient and innovative way. In this context a developer led approach, if selected, should still deliver an optimal offshore grid.

11.4. Section 3.7 of the consultation also recognises the choice that the existing regime allows developers. However, we are concerned that it states that this would exclude radial links from the delivery models (as discussed in question 12). We do not see this as an either / or choice but rather a blend, where delivery models discussed under question 12 could be used for any offshore transmission with developers retaining a degree of choice as to whether and what they take forward with Generator Build.

11.5. With respect to the above, we note that radial solutions could be shared with other parties and or be split between offshore substations. For example, a generator might connect to an offshore substation using a radial offshore transmission link, but there could then be another radial shared link to shore. The generator may or may not wish to take on both sections of the radial links through Generator Build and the regime will need to recognise and accommodate this flexibility.

11.6. Further to the above, and noting also, that question 12 of the consultation relates to the use of the developer led model in a wider context, i.e. beyond just radial solutions, we believe that the principles of choice should be considered in the extent to which a developer can take on offshore transmission works via Generator Build. Overall, there is likely to be a point at which developers will not want to take on offshore transmission works which are more substantially shared. It may be that radial and shared radial sections can be developer-led by choice, whereas wider offshore transmission works which are more substantially shared are taken on by another party.

11.7. Finally, we disagree with Ofgem's statement that "we do not think there is a need to change it [the OFTO regime]". The issues highlighted to Ofgem by OWIC in their 2019 paper[3] on "short-term changes to the OFTO regime" have not yet all been addressed, and will not be as part of the scope of OTNR. We refer in particular to issues regarding fair allocation of risk and asset health for transmission assets.

12. Question 12: Please provide your views on each of the delivery options we have described in this document. In providing your views, please comment on the issues we have raised. Please also give your views on the implementation issues we have raised.

12.1. As noted in paragraph 11.1, the existing regime works well, and is the solution most likely to deliver the connections needed to meet the 2030 ambitions and limit project delay risk. It is understood by developers and minimises both risk and cost. If this can be integrated into the HND, to bring forward coordinated/integrated connections, this is most likely to deliver on the objectives set out in the OTNR, subject to the commercial issues addressed in paragraphs 5.8-5.11. We also make the follow general observations:

Urgency for 2030

12.2. It is currently Q3 2021, with Ofgem looking to consult on a delivery model in Q4 2021, and a prospective implementation in late 2022. Round 4 offshore wind projects are already known, and developers are already working on delivering those projects, including under the existing regime with what would likely be radial connections to shore. ScotWind projects will shortly also become known with developers wishing to progress those projects. With many developers' progress investment is at risk in order to ensure 2030 delivery can be achieved (despite substantial ScotWind leasing process delays). In both leasing rounds, developers have already made significant resource investments in moving projects forward and have signed connection agreements with NGESO. The projects in question can contribute materially to the reduction of greenhouse gas emissions. Therefore, time is of the essence and delays in establishing delivery models that allow forward movement will be at the detriment of delivery for 2030, something that is not in the interests of present and future consumers.

12.3. The ESO and TOs (and OFTOs) are not sufficiently incentivised to progress timely delivery of consents for network reinforcements. These parties are not exposed to liquidated damages, for example, to ensure that connections are consented and approved on time for individual connections. This is in contrast to developers, who are strongly incentivised to deliver consents for all the necessary offshore infrastructure, because they bear very material commercial consequences if there is delay. Placing the consenting responsibility on the ESO/TOs/OFTOs could result in delays simply as a result of poor incentivisation adding risk to offshore developers. This misalignment of drivers will therefore result in inefficient outcomes for consumers.

[3] OWIC, 2019 "Transmission Review: Short term solutions" https://www.owic.org.uk/documents

12.4. Delayed connections expose developers to increased financial costs and risk. Specifically, the developers can be exposed to further option payments under TCE R4 or ScotWind Options for Lease, and also to late delivery penalties under the CfD. There may be penalties under commercial offtake contracts too. In the likely event that protections are not provided commercially then it may be necessary for the Government (or its agents) to provide those protections or mitigations instead.

12.5. In addition to the above, whichever delivery models are taken forward, the most fundamental tenet they must be judged on is their ability to deliver 2030 targets. They must therefore facilitate suitably experienced parties to move forward quickly and effectively without any delays which could otherwise be avoided.

Ofgem's role and the need to facilitate up front work

12.6. We understand and agree with Ofgem that the models set out will all require a degree of change in the regulatory frameworks. Ofgem has outlined the work it sees for itself in this respect and, given the imperative of achieving 40GW by 2030, we encourage Ofgem to make, with urgency, the appropriate changes to the models that are best suited to deliver the 2030 targets. Parties should be allowed to commence work ahead of the changes being implemented with a level of comfort provided by Ofgem, e.g. on expenditure and cost recovery. We further note that the HND is expected from NGESO by January 2022 and that from this point on, delivery parties will be in a position to move forward. This should not be hampered by having to wait for regulatory framework changes to be put in place.

12.7. Further to the above, we note that initial tasks by delivery parties following delivery of the HND will be relatively low cost and low risk, involving initial scoping of outline designs and initial reviews of consenting options. To put it another way, delivery parties should be enabled to undertake this low cost and low risk work whilst the frameworks are finalised and put in place.

OFTO tendering

12.8. As Ofgem appreciates, OFTO tendering processes can take around a year (more than 10% of our available time to 2030). Therefore, if a model with an OFTO is used, it is essential that the point at which OFTO tendering is undertaken can be run in parallel with ongoing design, consenting and construction so as to not introduce a delay. The current Generator Build model illustrates this well. Models that effectively pause delivery while OFTO tendering and appointment are undertaken should not be considered.

Capability

12.9. To date, the delivery of the infrastructure associated with offshore wind has only been delivered by developers. This means that any third party delivery model, be that OFTO or TO, will require significant capacity building within that party. This includes the design, consenting, construction, supplier relationships and the integration with the windfarm. In addition, the only party that has a detailed understanding of the operational aspects and marine environment are the OFTOs. We believe that building this capability and understanding will take time, and could add risk to project delivery – particularly if the third party is focused on one element and is not properly incentivised to deliver a holistically efficient value chain.

12.10. Furthermore, building this capability and capacity to deliver connection from the middle of this decade will be a significant addition to the obligations of the TOs, falling in the middle of the RIIO-2 price control, which already requires significant work and investment on the onshore transmission system.

Option 1 – TO build and operate

12.11. This model extends existing monopolies. This is not in the interests of the consumer and should merit no further consideration unless it is clearly the only model to be able to deliver the offshore transmission infrastructure required for 2030, in whole or in part. This may be the case in zone with one or more wind farms connecting to a TO-owned/developed/constructed HVDC bootstrap, for example.

12.12. We agree with Section 3.64 of the consultation that the onshore TOs do not have significant experience in delivering offshore infrastructure, as noted above. We are concerned that TOs may not be able to build their capabilities on the existing timescales. To date only two major TO owned offshore infrastructures have been delivered, (i.e. Caithness-Moray HVDC and the Western Link HVDC) although other similar links are in development phases and there are smaller capacity connections to Scottish islands.

12.13. We would also question whether onshore TOs are appropriately resourced to take on this additional workload. The experience of many RenewableUK members to date is that the TOs are already extremely busy in delivering and operating onshore transmission. Resourcing is, however, probably an issue for all organisations taking on and delivering additional major new infrastructure beyond existing workloads and having a clearer picture of offshore infrastructure would assist onshore transmission infrastructure..

12.14. Furthermore, legislative changes would be needed if this option is to be pursued. To provide offshore transmission an offshore transmission licence is required (or an exemption to this). Section 6C(1) of the Electricity Act 1989 give powers to the Authority to make regulations to determine, on a competitive basis, the person/organisation to whom an offshore transmission licence is to be granted. The TO would need to be granted an Offshore Transmission Licence to transmit electricity generated in offshore waters as is proposed in this scenario. However, the option is inconsistent with the legislative requirements as the licence would not be determined on a competitive basis.

12.15. Finally, we do note Ofgem's comments that this could be relatively speedy given one party will be responsible for everything end to end. This is a reasonable comment, although many would argue the incumbent TOs are far from speedy or efficient compared to other parties. The TOs do however have a good appreciation of the design, consenting and construction processes, albeit from onshore.

12.16. We would note some positive aspects of this option: a single party reduces interface risk. There will be one party delivering the entire development, design and construction phase for a zone interfacing between the onshore grid, and therefore offshore grid and windfarms may be less of a risk. Also, the asset the O&M costs should be fully considered up front and the TOs might be able to incorporate innovation earlier in the design process.

Options 2 and 3 – TO design, consent, build (or OFTO build)

12.17. Unlike option 1, these options do not extend existing monopolies and do introduce competition, but we believe that the risks associated with TO deliverability still remain. There are still questions to be asked over the resource and low level of experience of the onshore TOs in designing and consenting offshore infrastructure (and building it for option 2), also for the OFTOs were they to take on the build phase.

12.18. Probably a key downside for options 2 and 3 is that there is little incentive for an onshore TO to take forward infrastructure it will not own.

Option 2: TO build; OFTO operate

12.19. This model would be similar in many ways to the Generator Build model and this is a well-established and relatively efficient model after over a decade of use.

12.20. This model will require transfer of assets from the onshore TO to an OFTO via a competitive tender. Whilst the tender process will take time, it can be run in parallel with construction in a similar way to Generator Build OFTO tendering currently typically runs in parallel with construction. This means less time is lost.

12.21. Another important advantage of this model is that not only does it mimic the existing and well understood Generator Build model, but it has many synergies with the (late) CATO proposals meaning there will be efficiencies in developing and running it given much effort has already gone into CATO.

12.22. This model might provide better incentives for the TO to build an efficient and economic asset if disallowed costs are not recovered via the divestment or through the RIIO reopener process, and it could allow the constructed asset to benefit from cost of capital optimisation associated with the OFTO process. This would require a transparent and clear asset valuation process to remain in place.

12.23. We also note that OFTOs have experience operating offshore transmission networks so might be better placed than the TOs to take on this role.

12.24. Late competition should not delay the connection of offshore wind assets, as the transaction takes place after the windfarm and grid are operational, which is important bearing in mind the tight timescale to reach 2030 targets. However, the GCC clause might need to be assessed for larger coordinated assets.

12.25. We note that, TOs might not consider the grid asset holistically if they do not face any costs of ongoing operation (under the current process developers still face these costs via TNUoS). So clear incentives need to be in place to ensure that the design and construction is also optimised from an O&M perspective.

Option 3: TO design; OFTO build and operate

12.26. Whilst option 2 is very similar to the current Generator Build model, option 3 allows OFTOs the option to increment their involvement into construction. This will improve their overall capabilities and service offerings moving towards the enduring regime where a more involved OFTO (possibly even early OFTO) may be a necessary and/or desirable way forward. This was the original intention of the OFTO regime. OFTOs have also shown to date the efficiencies they can bring from the private investment sector.

12.27. Option 3 also introduces fundamental risk as the incumbent OFTOs lack the necessary expertise to undertake construction activities. Therefore, a new form of OFTO which does have this expertise would need to come forward in a short time.

12.28. Additionally, it is not clear that it would make commercial sense for a party to construct and operate assets it has not designed and optimised in the way this model suggests. Most of the procurement of long lead items and high value works of these projects will need to begin early in the pre-construction phase. Giving this responsibility to the TO would mean OFTOs will have minimal ability to leverage their commercial experience to optimise the construction model, suppliers and commercial contracts. It is not clear how this would impact the cost assessment process. On the other hand, later construction and procurement work would be undertaken by counterparties who have a greater understanding of the technology and the marine environment (albeit only from an O&M perspective). We also note that TOs have consenting knowledge from an onshore perspective.

12.29. We also believe that bringing in late competition could optimise the associated financing during the capital development stage – we would note that could be higher than current OTFO transactions seeing OFTOs have not delivered the construction element of a windfarms grid delivery before. From a windfarm developer's and consumer perspective this could ensure that TNUoS costs are minimised.

12.30. We believe that the model would require additional incentives on both the TO and the OFTO to ensure that, the DND is based on a holistically economic and efficient design, rather than simply the easiest design to consent. Additionally, there must be a clear and transparent process to ensure project design information flows freely between the TOs and the OFTOs, and that OFTOs are engaged early in the process. There may need to be clearer incentives for the TO to deliver a timely and high quality DND. This would reduce the risk of delays outside of the windfarm developer's control and the risk of unexpected costs. It might also allow for innovation to be factored in earlier in the development process. We note that compared to the TO driven models, OFTOs will be better incentivised to deliver assets that de-risk their long-term stable returns, meaning that construction delivery and quality will be within their interest. OFTOs will be incentivised to deliver the construction programme timely, as incentives and their revenue model should also be linked to achieved connection dates.

12.31. We note that the application of competition in the development process could add time to the delivery of pre-2030 offshore windfarms, and Ofgem need to ensure processes can be run in parallel to tender award, perhaps during the consenting process. If this is not the case then the tender process could put the 2030 offshore wind targets at risk; as an example, the current OFTO process takes upwards of one year. We recommend that a successful OFTO should be known early in the pre-construction phase, to ensure efficient procurement can begin.

12.32. We also note that under this model interface risk is higher with three parties involved in the process, and warranties and liabilities will need to be duly considered. Overall, we recommend that the risk of delay to the windfarm should be underwritten by the TO or OFTO, depending on which phase the project is in.

Options 4 and 5 – (Very) Early OFTO

12.33. Both of these options will require OFTO tendering after the HND is completed by NGESO. At this point, and during the OFTO tender processes there will be no party progressing the design and consents of the offshore transmission works until an OFTO has been appointed. As already noted in comments above, this will result in a delay of around 12 months, whereas other options avoid this. For this reason and given that speedy delivery of the offshore transmission assets is the key aim, we believe these options should not be taken forward as part of the Pathway to 2030 work.

12.34. Notwithstanding the above, options 4 and 5 can promote competition and innovation and allow for flexibility and design change during the consenting process and may be the most appropriate means to deliver some of the ‘wider’ shared offshore transmission infrastructure in the longer term. Given also that a very early OFTO was the original intention of the offshore regime, these options should be taken through for consideration in the enduring regime.

12.35. In relation to Option 4, we have already commented on the concept of DND above noting that it will introduce a delay of around 6 months and is probably an unnecessary element of the delivery process as proposed.

Option 4: Early OFTO competition

12.36. This model may allow the OFTO to better utilise innovation and supplier relationships to reduce the cost of offshore grid delivery and this can be optimised earlier in the process. The model should ensure that an offshore grid design balances contenting and delivery risk, as the OFTO is leading both these processes, however post-build cost assessment may be required to ensure that delivery is cost optimal. We also believe that his approach reduces the risk of integration challenges as one party is leading multiple elements in the process.

12.37. We believe that the OFTO tender must be delivered efficiently, and there is a risk that the tender process could delay delivery seeing it harder to run in parallel to the delivery process. Under this model we assume that the DND will drive the tender and therefore a tender will need to take place after the DND but prior to pre-consenting works. To mitigate the risk of delay, Ofgem could consider whether third parties (TO or ESO) could undertake some of the pre-consenting activity including survey work whilst the tender is underway.

12.38. Under this model we believe that OFTOs should be incentivised to deliver the construction phase on schedule, ensure connection dates are met, and underwrite the risk of delays. We also believe that cost assessments need to be in place and a suitable milestone plan is clear and transparent withing the delivery phase, to ensure that OFTO capex is efficient and optimised, when determine the TRS value post-construction.

12.39. We note that OFTOs have not consented or delivered offshore grid connection assets in the UK to date, therefore there are still challenges around the skills gap and capacity required to deliver projects. However, we note that this could be lower than the TO delivery model as each OFTO will only focus on delivering specific assets, not the whole offshore network in their regulated area. Developers are still concerned about the risk of delay and the quality of connections, and we note that competition is only useful where there is enough liquidity to drive a lower price – in this instance Ofgem may wish to confirm the appetite among OFTOs to take consenting risk.

12.40. This approach is highly reliant on a deliverable DND, as the DND will likely drive all the tender and consenting works. This could require the ESO/TO to be incentivised to ensure that DND does not cause delay to the construction process, for Ofgem and the ESO/TO to ensure a successful transition and that a high-quality design meets consenting requirements.

12.41. This delivery model could encourage a level playing field during the OFTO tender as the DND will be known and fixed for all bidders, however, it may remove the ability for an OFTO to introduce innovative technical solutions that add competitive edge to their bid. The transition to the OFTO earlier in the process should ensure that the OFTO is able deliver procurement effectively and efficiently.

Option 5: Very Early OFTO competition

12.42. We believe that the very early OFTO solution is somewhat similar to the early OFTO solution, therefore the majority on comments raised above are also valid for this model.

12.43. However, there are some differences. For example, a DND undertaken by the OFTO might allow better synergies from a procurement and innovation perspective and could reduce interface issues between parties.

12.44. This scenario might prove challenging to assess from a tender perspective because the scope of delivery is not clear, meaning that there could be a wide range of solutions and costs. If this route were to be taken it would require Ofgem to perform significant due diligence on the proposed solutions to ensure that they are deliverable and fit for purpose.

12.45. We also believe that Ofgem should test the appetite amongst OFTOs to deliver the DND alongside the consenting, we note that if there's limited competition in the market this could reduce the options for delivery, may increase delivery risk without gaining the full cost reduction benefits.

12.46. As per option 4, the OFTO must be incentivised to ensure that they meet the delivery obligations throughout the project phases, underwriting any delay risks.

12.47. The HND will likely set out the key parameters of the design and as such limit the ability for innovation. Innovation can also increase the operational risk profile – increasing the cost of capital to deliver and operate the assets which is likely to outweigh any innovation advantage. Further, there are likely to be such high degrees of uncertainty associated with the final solution at early stages of design, it is highly uncertain that any significant innovation would ultimately be used as part of the final solution.

12.48. Thus, the cost assessment process should be reviewed (as noted in the 2019 OWIC paper). As with the current OFTO regime rules, innovation can also be thwarted because of the uncertainty of the cost assessment process. Developers are often put-off from innovating due to the uncertainty associated with cost-recovery processes and the pressures from CfD bid preparation to keep costs known and as low as possible. The interaction between the OFTO-build and the cost pass through to developer should be assessed. In addition, as it is unclear what entities would be likely to come forward as OFTOs in this Option it is therefore difficult to say if innovation is likely.

12.49. This model locks-in a licensee at a very early stage. This inevitably reduces the scope for strong competition on cost variables during the construction and operational stages of the licence term – including financing, which the current OFTO regime has very successfully delivered – and is likely to result in higher consumer costs overall.

12.50. Finally, the consultation puts forward a number of options for network design and delivery, but does not set out who is expected to undertake the consenting process for the network. Under the current regime it has been developers, who take on the risk and have the experience. If this work is to be led by an OFTO or TO, developers will need absolute confidence that the consenting process can be managed in a competent and timely fashion, which does not leave projects open to challenge or review and does not undermine economic confidence in the industry. It is suggested that specific thought also be given to the co-ordination of Environmental Impact Assessment, cumulative impact, and survey works. Where any transition is proposed, it will be essential that well-planned and carefully considered transitional arrangements are put in place which ensure that no developer or development is subject to undue delay or uncertainty.

Option 6 – Generator Build

12.51. We have already commented extensively on the developer led (Generator Build) model in our response to Question 11 of the consultation. This option is well established and efficient and involves competition. The developers are experienced and resourced to undertake the necessary work, and there are no delays through DND or OFTO tendering.

12.52. It is worth noting that developers may not wish to take on wider offshore transmission infrastructure that is identified in the HND and that there is a lack of incentive for them to do so. The main incentive to undertake Generator Build at present is in ensuring delivery of the offshore transmission assets for the developer's own project(s) and controlling spend and risk therein.

12.53. This model also raises questions over what happens when a developer undertaking offshore transmission work (for others) changes their generation project plans or terminates the project altogether. We would hope this is manageable with other involved developers who might step in. We address some of these points in our answer to question 13, below.

General conclusions on delivery models for 2030

12.54. Within the context of the HND there is a high likelihood that some Pathway to 2030 projects will have a radial connection. To secure these projects within a 2030 timeframe it is essential that Option 6 is made available to developers. Whichever model is pursued, Ofgem and BEIS must put in place adequate incentives to ensure the connections are in place on time.

Delivery Model	Key Considerations
1. TO Build and Operate	Option 1 does not facilitate competition. Suitable for concepts involving connection to TO-owned bootstrap in early opportunities. Could be explored further during enduring regime.
2. TO Build > OFTO Operate	Introduces mid-late stage competition. Offshore build experience required within onshore TO for option 2 or OFTO for option 3. There is little incentive for onshore TOs to take forward infrastructure it will not own in option 2. New form of OFTO with this expertise will need to come forward in a short time to enable option 3.
3. TO Design > OFTO Build and Operate	
4. Early OFTO Competition	Both options 4 & 5 can promote competition and innovation, and allow flexibility of design. For option 4, Detailed Network Design (DND) stage could present delays around 6-month. Option 5 locks in OFTO licence at early stages and could reduce scope for competition across later stages (construction and operation).
5. Very Early OFTO Competition	
6. Developer design and build, OFTO operate	Option 6 is well established, efficient and involves competitions with no delays due to DND or OFTO tendering. Transmission solution is optimised for a developer's own project, and raises questions of risks to other developers for shared offshore transmission approaches.

12.55. In parallel with this, extending the mandate of the existing TOs to design, consent and potentially build offshore (with transfer to an OFTO) would provide a mechanism for wider system works to be undertaken as an alternative to developers.

12.56. In practice, the HND will be a determining factor as to what each party can most suitably do and the HND itself should be designed to facilitate delivery and the best delivery models. This may mean that the HND is not the cost optimal design but is still a reduced-cost design that can be suitably carved up and delivered according to the strengths and capabilities of the parties and models assigned to deliver for 2030.

Additional points:

12.57. For models 1-5: Where known defects are identified in the transmission assets constructed by a party other than the generator, what indemnification will the generator get for when such defects cause outages or require outages for repair? Generator Developers are required to indemnify OFTOs for such defects on the basis that they have constructed the assets. Where the generator has not constructed the assets it should have the right for uninterrupted availability to transmit its power, equivalent to what onshore generators receive.

12.58. In models 2 & 3: Will the TO indemnify the OFTO for defects in the asset and underwrite the construction risk where the OFTO is unable to get insurance on certain transmission assets? Similarly, how will the generator be covered for outages arising from latent defects that arose in the construction phase?

12.59. Finally, it is important to recognise the significance of the (mis)alignment of incentives between the developer and any other party (TO or OFTO) that is charged with Pre-construction and/or construction works. The OFTO build model has not been pursued to date because the developer is best placed to minimise risk and optimize solutions.

Moving away from this model carries significant risk for developers that government must either manage or mitigate, and this will bear some cost.

13. Question 13: Please describe any feasible delivery options that we have not set out in this document.

Developer joint venture

13.1. A developer joint venture might be attractive where wider and shared transmission infrastructure is ultimately needed by a number of developers, but no one developer wishes to take on the works in isolation. This could offer a developer-led (Generator Build) route for delivery of all the necessary offshore transmission infrastructure with OFTOs being introduced at points of construction or operation. This is essentially option 6 with greater potential to take on more of the necessary works; or this could take the form of an OFTO led developer JV EPC, as discussed in the Ofgem 2014 OFTO developer build paper. As noted above for early models, the tender process could delay the start of works, so this may need to be run while the DND is developed.

Delivery model	HND	DND	Pre-construction	Construction	Operation
Developer joint venture	ESO	Offshore generator(s) / JV	OFTO	OFTO	OFTO

Third party models

13.2. Third party models are also worth considering. This could be a party willing to progress the offshore transmission works but not wishing to either construct and own, or own, at which point an OFTO is introduced. There are many organisations which are geared to consenting infrastructure and then selling it on, and that are geared to delivering infrastructure but not owning it. Many of these organisations are used to dealing with tight timelines and appropriate contracting structures, including incentives and penalties such as liquidated damages for late delivery. Perhaps the main issue with a third-party model is its relatively late introduction to the OTNR process and the need to put the frameworks in place for it as opposed to adapting the existing transmission frameworks.

Delivery model	HND	DND	Pre-construction	Construction	Operation
Third party models	ESO	Third party	Third party	OFTO	OFTO

MPI questions

14. Question 14: Do you think we are focusing on the right models at this stage, or are there other models we should be considering? Is it also necessary to consider the evolution of such MPIs from pre-existing assets? Ultimately, should Ofgem accommodate multiple MPI models (e.g. IC-led and OFTO-led) or just one? What factors influence your answer?

14.1. The models suggested appear sensible. Generally, MPI opportunities are quite unique in their nature. These opportunities are heavily dependent on their geographical position of assets and the delivery plan of host projects, be it offshore windfarms or interconnectors. MPIs require alignment across assets, construction schedules and regulatory regimes on both sides of the project, ultimately this alignment should allow for the MPI to de-risk each element and move forward through FID as a coordinated project.

14.2. Ofgem should accommodate both IC-led and OFTO-led models, particularly as in the Early Opportunities and Pathways to 2030 workstreams (as compared with the Enduring Regime) both are equally likely to be deliverable as the other.

14.3. For the IC-led MPI model, existing IC assets can be extended to include an offshore generator. For OFTO-led MPIs, the project Kriegers Flak connecting Denmark and Germany demonstrated how an existing offshore connection system can be enhanced to become an IC-system. Therefore, we believe it is indeed necessary to consider the evolution of both MPI models from pre-existing assets.

14.4. The decisive factor from a developer's point of view is predictability, irrespective of the choice of one model or the other. Consequently, it is essential that MPI development plans are binding and guarantee risks/costs sharing as well as timely completion of the interdependent assets.

14.5. The concept of energy islands also exists, and whilst we agree that IC-led or OFTO-led MPIs are likely to be frontrunners in terms of delivery, Ofgem should ensure that regulatory and Code changes to facilitate MPIs do not exclude potential future energy island concepts (nor are they new models in their own right).

14.6. It may be that assets (either windfarm or interconnector) earlier in the development cycle could have more scope to move between the two models assuming that any change does not delay or put their individual assets at risk.

14.7. We do not consider that MPIs would arise from pre-existing assets due to the technical need for electrical sharing of transmission assets to be planned from the early development phases of both generation and interconnector projects. If Ofgem are to consider the evolution of pre-existing assets into an MPI it is important that, either through regulatory or commercial means, the existing assets are 'kept whole' and that they are treated on an 'opt in' basis.

14.8. As an example, an offshore windfarm would need to retain its grid connection agreements (under the current regime) – as these are vital for both the CfD eligibility where the windfarm requires, an"agreement to connect to the national transmission system for Great Britain" and where the windfarm has to meet technology specific grid connection checks,"where the Applicant has specified in the Application that a Direct Connection or a Partial Connection applies or is to apply to the relevant CFD Unit, there is nothing in the Connection Agreement that indicates that the technology of the CFD Unit to which the Connection Agreement applies is not the same as the category of Eligible Generating Station for the CFD Unit specified in the Application".

14.9. In addition to the CfD point, the developer will need to continue with the development works and development process in order to meet the project delivery timescales and changing/novating the grid elements may delay this process. We also note that windfarms are developed under connect and manage and interconnectors are developed under invest and connect, therefore it is important that the appropriate grid connection regime does not delay the project timelines and is compatible with the whole MPI solution.

14.10. We also believe that currently the developer is best placed to deliver the grid works for an offshore wind project in late-stage development, in this instance the offshore developer is incentivised to deliver a timely and high-quality grid asset to allow connection of the windfarm. The inverse of these point will be true for parties with late-stage development interconnector assets.

14.11. We note that the that current legislative arrangements were never developed with MPIs in mind . However, we do believe that existing legislation (with some legislative and regulatory flexibility), licences, codes and methodologies can, in combination with exemptions and derogation be made to work for early MPIs. It may be beneficial to consider a coordinated set of changes to legislation, licences, codes and methodologies for an enduring solution.

15. Question 15: Do you agree with this position with regard to ownership structures of MPIs under the current framework?

15.1. We agree that the current legal framework foresees separate responsibilities for ownership of connected transmission and generation assets and that any changes to that require significant legal changes. Looking at MPIs under the OFTO-led model, the current framework adds a third party which has to be involved in coordination processes, adding complexity in the context of MPIs being realised in the 2020s, in particular via the IC-led MPI model.

15.2. Whilst MPIs represent a more efficient use of transmission infrastructure as compared with a counterfactual of radially connected offshore wind farms in the same geographic area as interconnectors, the lack of a clear regulatory framework for near-term development and long-term operational conditions of MPIs is currently undermining the business case for these types of assets. This is all very closely linked with the Trade & Cooperation Agreement (“TCA”) between the UK and the European Union, and subsequently would require primary legislation to reduce complexities.

16. Question 16: What are the commercial, operational and regulatory factors that would drive a developers preference for either the OFTO-led or IC-led MPI model? and do you envisage a different usage of the component assets of an MPI depending on the MPI model?

16.1. In an IC-led MPI, coordination between two territories’ regulatory provisions is needed, which adds complexity and may therefore delay the project. This is of particular relevance when developers must pay option fees for their lease as it is the case with the Leasing Round 4 developers. From a developer point of view, the OFTO-led MPI model would limit coordination responsibilities and therefore support the timely completion of projects.

16.2. If the MPI evolves from existing assets, the actual capacity of L1 and L2 may foster the application of one or the other model. If the MPI is designed as such from early development phase, we don’t currently envisage a different usage of its component assets.

16.3. There are several elements that could drive a developer's preference for either an OFTO or Interconnector led MPI model. These elements are often related to the development cycle for host project, or the 'first' assets – where the developer has to keep the development on track and maintain optionality if the MPI solution does not materialise. The core elements that a developer (of the interconnector or windfarm) would consider are:

- De-risking the primary host assets under development – be that an offshore windfarm or an interconnector. MPIs are complex and require significant alignment across geographies, projects, regulatory landscape and technology therefore the option to continue to develop individual host projects is important. In the pre 2030 workstreams the primary host assets are generally significantly far down the development pathway.
- The commercial framework to ensure that both the windfarm and the interconnector (and OFTO) are not adversely affected by an MPI solution. For example, will the windfarm still be eligible for the CfD and the interconnector still eligible for the Cap and Floor. What will the arrangements be the network charging, balancing, TEC?
- The timeline and complexity of regulatory change: is there a need to change primary, secondary and European legislation, as well as grid codes, and a route map and timeline to do so?
- Smooth operability of the whole MPI asset during the whole lifetime: does the solution allow the MPI to optimise market to market flows from day ahead to physical delivery, and how will the balancing and asset maintenance be managed?

17. Question 17: How would the line to shore (L1) be used in practice and what would you consider to be the primary and secondary activities from a practical perspective? Please provide views for both the IC-led and OFTO-led models, highlighting any differences between L1 usages across the two models.

17.1. From a practical perspective L1 will be used to evacuate offshore wind and to manage market to market cross border flows. Under the proposed MPI solutions (both OFTO and Interconnector led) offshore wind would require physical assess to the grid assets, indicating that cross border flows will be optimised around the offshore wind forecasts and delivery. The exact use of L1 would depend on the sizing of the line, and whether cross border flows are available at maximum wind output

18. Question 18: Are there any barriers within the current frameworks, such as definitions within the CUSC, SQSS or other industry codes, that might prevent the line to shore (L1) being classified as either an OFTO or an interconnector while undertaking other secondary activities?

18.1. To date, we have not identified any elements of the industry codes that would prevent the line to shore (L1) being classified as either an OFTO or an interconnector. We note that L1 would require bi-directional electricity flows.

18.2. However, there are still code (and code related) challenges related to the MPI assets that we would like to consider further. These include the treatment of TNUoS costs within an MPI model (under current conditions, interconnectors are exempt from TNUoS cost, but offshore wind farms are not), to ensure that the charging base does not disadvantage any of the assets in an MPI configuration. In some cases, derogations may be required.

18.3. As noted above (paragraphs 6.1 and 7.5) We believe that a ringfenced and dedicated resource is required within the ESO to enable code changes at pace. There is a risk that, if left to the current code change process, the timetable for code evolution could delay or reduce early opportunity projects.

19. Question 19: What are your views on the feasibility of adopting a regime that requires developers to submit evidence to support their licence application (for assets that form part of an MPI) and commit to regular performance reports? Would this be practicable, proportionate, and effective? Are there other options that work well for industry that we could explore further?

19.1. We welcome Ofgem's view that flexibility may be required in the way MPI assets are regulated, and we believe that MPI developers may need to work with Ofgem to consider this point further.

19.2. Developers would presumably only ever assume the generator license and we see no necessary changes to this one license over time that would require regular reports to re-assess said license. Any re-application requiring a performance report should not be necessary within the first estimated life span of the generator of 20-25 years.

20. Question 20: What are your views on the practicality of transposing obligations from one licence into another, which obligations would be the most important to incorporate into a remaining licence?

20.1. In our view, this concerns the IC- and OFTO-licenses, not generation. We therefore leave the consultation to the relevant stakeholders. Although not a licencing restriction, the 18 month GCC clause might need to be considered for MPIs to ensure that commissioning can take place across the whole system.

21. Question 21: Do you think the exemption provision with the Act offers any solutions to licencing MPIs within the current framework, even if only a temporary solution until a potential enduring solution is implemented?

No comments

22. Question 22: Are there any aspects of the priority dispatch and curtailment arrangements, the TCA, or the cross-border trading arrangements that are adopted in UK that might influence the choice of MPI models?

22.1. We believe there could be a challenge with the "margin available for cross border trade" and the associated 70% rule. In this context we welcome any engagement between the UK Government and the EU commission on this point, and clarity should be sought on whether this rule applies to MPIs on the third country border, or whether derogations are appropriate. This regulatory barrier is a significant risk and could impact on the delivery of early opportunity MPI projects.

23. BEIS Question 1: What do you consider to be the key challenges to the establishment and operation of MPIs in the UK presented by current and proposed regulatory requirements applicable in EU Member States or other countries which MPI projects may connect with, or by the TCA? (e.g. regarding the efficient operation of MPIs under both the Home Market and Offshore Bidding Zone approaches). Are there further domestic challenges to these possible market design options

23.1. We believe that the OFTO-led MPI can be better implemented under a Home Market solution.

23.2. We note that on an EU Member State level both offshore bidding zones (OBZs) and home market solutions are being considered for MPI developments. For pre-2030 MPI projects, we do not believe that the bidding zone model is appropriate and believe that an OBZ approach is unlikely to be realised in time for investment decisions.

23.3. For UK offshore wind projects both the ‘home market’ solutions and the ‘OBZ’ solution would need to be CfD compatible, and maintain the price hedge provided by the CfD instrument. If the windfarm is disadvantaged under the MPI trading arrangements compared to radially connected windfarms this will have a knock-on effect on CfD bidding, and ultimately project realisation.

23.4. We also note that wind developments generally take FID on known and stable regulatory and market arrangements. These arrangements impact the cost and financing of a project. Therefore, a move in market design, from home market to OBZ during the operation period of a windfarm would need to carefully be considered especially where any negative impact on the windfarm revenue could have a knock on effect on investor confidence. We recommend that original market solutions are retained for the operation life of the windfarm, and at the very least the windfarm is kept whole if market designs do change.

23.5. However, for both these market approaches, many regulatory questions remain, and EU regulation is not yet harmonized in these regards. Challenges and open questions include uncertainty regarding applicable regulation, tender and TSO responsibilities, promotion schemes, general cost-benefit-distribution and, with regard to all of these aspects, public acceptance in the connected territories.