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Dear Rebecca,

Changes intended to bring about greater coordination in the development of offshore energy networks

We are pleased to respond to your consultation on changes intended to bring about greater coordination in the development of offshore energy networks.

We support the overall BEIS and Ofgem Offshore Transmission Networks Review (OTNR). It is needed now to ensure that the infrastructure required to facilitate the government's 2030 and Net Zero offshore wind targets is delivered at the most efficient cost for consumers. In this context, we welcome the opportunity to comment on the issues raised in this first OTNR consultation particularly in relation to the Pathway to 2030 (PT2030) workstream.

The Offshore Wind Sector Deal agreed with government sets the UK an ambitious target of connecting 40GW of offshore wind generation capacity by the end of this decade. PT2030 will be critical to successfully realising the Sector Deal and thereby maintaining the required trajectory to achieving Net Zero in 2050.

ScottishPower is a leading offshore windfarm developer with a proven track record in the UK over the past number of years utilising the generator build (developer led) approach to successfully deliver offshore generation and transmission assets. Following the successful delivery of our West of Duddon Sands joint venture project with Orsted, and our East Anglia ONE (EA1) offshore windfarm with first export in 2019, we are currently in the process of divesting the associated transmission assets in Tender Round 6.

We have submitted project applications for ScotWind for both bottom fixed and floating sites. To maintain a competitive approach and allow for planning and consenting considerations, we will be looking to secure a route to market at the earliest opportunity for any of these ScotWind projects that we successfully secure. As such, we welcome the opportunity to work with Ofgem and ensure PT2030 facilitates delivery of coordinated offshore network solutions in the timely and certain manner required for these projects seeking to connect in such timescales.

Detailed responses to the consultation questions are in Annex 1 to this letter, however we would like to highlight the following points regarding PT2030:

1. **Priorities for achieving a sustainable deployment trajectory to 2030** – As set out in the consultation, offshore wind projects in scope of PT2030 constitute a significant proportion of the Sector Deal's 40GW target. In this context, it is important to ensure the momentum and trend of offshore wind deployment is not unduly paused or hampered as we transition to the reformed regulatory regime, as this could risk a less efficient "backloading" of the Sector Deal. We believe projects in scope of PT2030 could realistically be able to secure a route to market from the middle of this decade. With this in mind, we believe PT2030 should aim to have solutions in place regarding any identified coordinated network solutions in time for potential connections in the middle of the decade. In practice, this may require a prioritisation and acceleration of shortlisted regulatory issues. In particular, offshore wind developers will require certainty regarding the regulatory treatment of shared transmission assets identified as a result of coordination, specifically:
    - the boundaries between shared and sole use offshore transmission assets;
    - translation of user commitment currently used in onshore transmission, and adapting it as appropriate to apply to offshore shared transmission assets, including how the resultant liabilities are allocated between all connecting generators;
    - recovery of shared offshore transmission asset costs to be socialised across all network users via TNUoS; and
    - the allocation of risk between parties, notably liability for the delivery of the transmission assets in the various delivery options.

2. **Significant Code Review (SCR)** – An SCR appears to be the primary route by which Ofgem should develop and implement industry code changes, including charging methodologies and industry codes, required to facilitate the PT2030 reforms. As noted above, timescales necessitate as close to immediate changes as possible. This will require the Early Opportunities SCR to also develop solutions that work for PT2030 projects. Both workstreams require the scope of reforms to be the minimum and simplest approaches required to facilitate shared offshore transmission solutions where they are identified in the Holistic Network Design, recognising that more considered and perfected approaches will be implemented via the enduring coordination regime. We suggest the following approach to a consolidated Early Opportunities/PT2030 SCR:
    - As set out in 1) above, the SCR should identify aspects (some of which are noted above) of the regulatory regime relating to offshore transmission assets that are necessary to develop further and clarify for offshore wind generators.
    - To simplify matters, the default approach could be to translate current onshore rules (for the shortlisted issues) to the offshore regime where applicable. Where not appropriate, our view is that the aim should be to make as few changes to established onshore rules as possible to adapt them for offshore.
    - The SCR should be implemented by Ofgem directing the ESO to make a finite and simple set of reforms with clear minded-to positions, eg translating the onshore approach which can be implemented in short order on the basis that it is established and well known to grid users.
    - Ofgem should aim to finalise the above on the SCR in advance of the Detailed Network Design of PT2030 projects, well in advance of consent applications.

3. **Holistic Network Design (HND)**– We agree that the ESO is best placed to undertake the HND, but this is nevertheless a new area of assessment for the ESO, requiring insights into areas such as consenting and planning which are outside its current scope of activities. We would therefore recommend Ofgem ensures the ESO is given appropriate objectives, resources, and incentives to help it focus on delivering an HND output that will ensure optimal offshore network solutions are deployed for offshore wind projects connecting up to 2030.

4. **Offshore Transmission Delivery Models** – We believe given the scale of delivery required to 2030, the full range of delivery models ie developer/generator, OFTO and TO, could be retained and selected based on the circumstances of each coordinated offshore network solution. All these parties have the capability to design, consent and construct to required timescales depending on the degree of coordination. We also believe that wherever practicable, appropriate competitive processes should be applied to offshore transmission infrastructure to secure benefits for consumers and developers. While we agree the ESO is well placed to undertake the HND, we think the delivery parties are better placed to undertake the detailed network design (DND).

If you have any questions regarding this response, please don't hesitate to contact me or my colleague Haren Thillainathan (hthillainathan@scottishpower.com).

Yours sincerely,

Richard Sweet
Head of Regulatory Policy

Annex 1

CHANGES INTENDED TO BRING ABOUT GREATER COORDINATION IN THE DEVELOPMENT OF OFFSHORE ENERGY NETWORKS - SCOTTISHPOWER RESPONSE

Early Opportunities questions

We think many of the issues in this section apply equally (if not more so) to the Pathways to 2030 (PT2030) workstream. Indeed, the focus of most of our responses to questions 1-7 is their application to PT2030. Accordingly, we expect Ofgem's SCR should have the scope to cover both workstreams. In practice, given Early Opportunities relates to "in-flight" projects, there is limited scope for application of the issues and concepts below.

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

No. We believe all relevant concepts have been identified in the consultation. However, we understand that concepts should be put forward by developers in an 'opt-in' approach as part of the Early Opportunities workstream, and those developers should be the ones assessing these options in the short term.

Given the pressing timescales, these concepts must be applicable to the PT2030 workstream and provide a basis on which to develop the Enduring Regime. In this context we would like to make the following comments:

- The boundary between generator sole use and shared assets should be clearly defined for all concepts. This is critical because the treatment of shared assets is key to ensuring coordinated solutions can be delivered, particularly for PT2030 projects.

- For all options, there needs to be recognition of the size of the applications developers are likely to be considering now, and in the future, prioritizing scale over other parameters. We believe it's going to be unlikely to see grid connection applications for sites below several hundred MW. Any shared infrastructure would need to be significantly oversized to avoid interdependencies (ie in terms of construction and economics) between generators and this will factor into how competitive they can be in CfD allocation rounds.

- For all options, there is a level of detail that the schematic diagrams don't account for at the moment, 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 total capacity of 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, which has already taken place to the maximum extent possible in some projects, such as our East Anglia One and Three projects, where for example, onshore cable routes and substation sites are shared but the respective assets are entirely separate.

- Bootstraps and Interconnector options should consider the flows of power, as well as the size. Connections need to ensure the system is getting an equivalent full-sized interconnector and full-sized Offshore Windfarm (OWF) as if they were dedicated connections. Similar considerations apply for the bootstraps, as there could be wider benefits for the system such as managing network outages and reducing curtailments. This should be considered in the plan.

- In the case of interconnectors sharing infrastructure with an OWF, clarity would be required to ensure generator output was not curtailed due to interconnector operations as well as any need for the generator to comply with system requirements across two different countries simultaneously.

We believe that although the intention will ideally be to require only minor Code changes and SQSS changes, the amount of time, and the industry consensus that will need to be reached to progress with new concepts and solutions should not be underestimated.

Furthermore, these concepts are a significant divergence from the existing grid connection agreements and existing framework for DCO approvals. Opening these up for review will certainly delay project timelines and potentially change projects costs, which must be avoided if we are to meet the 2030 targets via a steady and sustained pipeline of deployment. Delay would impact the local supply chain and the number of projects in the next CfD auctions. This is why it is imperative that this workstream is on an "opt-in" basis for developers given the high degree of uncertainty that it may bring and the advanced stage of development that the projects are working at.

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. Ofgem should highlight the benefits that both coordination and integration (which are two different concepts) are adding to the industry and particularly local communities, avoiding a narrow view on what coordination means, which at the moment appears to be only based on physical asset sharing.

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

It is important to consider anticipatory investment in the OTNR context. We believe the inherent level of risk and exposure is relatively low for the following reasons:

- The 2030 Offshore Wind Sector Deal and the Net Zero target are bringing forward a continuous pipeline of viable offshore wind projects which have a high probability of securing a route to market through CfD auctions, particularly so for PT2030 projects.

- Developers in the pipeline of projects will be significantly financially committed due to inter alia:
    - having a sea bed lease agreement or commitment to enter one, which has substantial associated liabilities;
    - having secured or being in the process of applying for environmental planning consents;
    - having secured a route to market (eg contract for difference (CfD)) or being otherwise incentivised to seek the earliest opportunity to secure one.

For this reason, offshore wind developers will have a strong financial disincentive to walk away or abandon projects. If undertaken robustly, factoring in commercial, planning and consenting considerations, the Holistic Network Design (HND) should lead to coordinated shared offshore transmission solutions in relation to highly committed generation projects. In this context, we believe the anticipatory nature of any shared transmission investments is limited as is the risk of stranding.

Nevertheless, we recognise there is a residual element of AI/stranding risk and we identify below further mitigating factors to offset this. With these mitigating factors in place we believe it is appropriate for shared offshore transmission assets to be regarded as part of an integrated transmission n system and be treated analogously to their onshore counterparts, namely that costs are socialised across all GB network users through transmission network use of system (TNUoS) charges.

Additional Mitigating Factors

We believe the following factors if introduced will reduce and offset remaining AI risk for consumers:

- We agree Ofgem has a role to play by approving coordinated shared transmission asset solutions. We think this could be implemented as a two-stage process so that Ofgem initially approves coordinated shared asset solutions identified in the HND. Subsequently Ofgem would conduct a cost assessment process once the offshore transmission developer (or any party responsible for the DND) has undertaken its DND with scope for a post-construction review. This approval process would reduce overall risk to developers reducing the costs of delivered transmission assets to the benefit of consumers. See our response to Question 5 for further details of the potential approval process.

- The concept of user commitment (UC) currently used in relation to onshore integrated transmission assets (CMP 192) could be adapted for use for offshore shared transmission assets. UC identifies the proportion of integrated assets that are effectively solely for the benefit of individual generators and accordingly calculates security and liabilities a generator must lodge to cover the risk of termination before connection. UC liabilities form part of a generator's connection agreement onshore. If appropriately adapted, UC will substantially reduce stranding in the unlikely event of termination before connection offshore. Furthermore, UC increases the generator's financial commitment in addition to the factors identified above and should therefore reduce overall AI risk. Two features we think an offshore UC would need to introduce are:
    - a methodology for allocating UC liability between coordinated generators; and
    - where generators are connecting at different times, requiring all the generators to sign connection agreements and provide UC at the same time or within a sufficiently close timeframe together.

It is essential to contextualise AI and the associated risk as we have done above and recognise that offshore is starting from a relatively low level of AI risk. With the additional mitigating factors, we believe it is appropriate for generators to offset much of the remaining risk through user commitment and consumers to bear the small residual risk by socialising the costs of shared offshore transmission assets. It can be easy to overstate AI risk which will lead to disproportionately complex and onerous regulatory solutions likely to jeopardise future offshore transmission and generation deployment.

Under the current OFTO regulatory framework, AI risk is unmitigated and is almost entirely left with the generator. This is because the current framework was developed at a time when the scale of wind generation capacity expected to connect was substantially below what is connected today, and only radial connections were anticipated. Accordingly, we don't consider the current approach has any validity going forwards with increasing coordination required and should therefore be discontinued.

Ofgem must ensure that, however AI risk is dealt with going forward, it does not allow for any funding arrangements to give certain developers undue advantages in forthcoming CfD auctions.

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

Not only for Early Opportunities, but also in the context of PT 2030 and Enduring Regime, we agree with the principle of assessing anticipatory investment for approval (see our response to Question 2) where Ofgem will need to see evidence that it is worthwhile and ultimately delivers on the objectives in achieving net zero. However, we argue that the responsibility of demonstrating the need for investment may not necessarily fall to the developer.

Projects that are to provide a wider system benefit should have the costs and benefits 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.

NGESO, the transmission owners 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, and be an iterative process. We are concerned that the urgency attached not only to the Early Opportunities projects, but also the Pathways to 2030 projects, is not yet fully recognised.

We believe a clear timetable for this approval process needs to be established with the clear aim of delivering 40GW by 2030 via a steady pipeline through the later 2020s. Furthermore, a clear process should be established providing the developer, the ESO and the regulator with timely milestones and decisions that could allow project progression.

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

Developers will be able to demonstrate reasonable expectation to connect based on the below points:

- 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 via Securities and Liabilities via CMP192) as well as set out a programme and connection date. It’s important to highlight that these securities and liabilities will significantly increase as the project gets close to the connection date.

- Projects due to connect in the mid-2020s are likely to be well-advanced, possibly with planning consent approved or due to be decided in the coming months. Projects with consent would have little flexibility to change from the consented parameters.

- Projects which have not been granted development consent may have entered into an Agreement for Lease, or be committed to signing this soon, which will attract substantial financial commitment.

In circumstances where higher user commitments may be required by the ESO, for example more TEC to accommodate multiple projects, a clear cost allocation for securities and liabilities should be in place to define how user commitments would be allocated across the zone. Circumstances in which the first project to connect bears the wider user commitment profile for the shared/coordinated asset will be unaffordable for developers, and this will require a way to socialise these costs across parties. We also see a risk of potentially creating an unlevel playing field in CfD auctions if certain developers are carrying more of the grid connection liabilities.

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

Although ScottishPower has no projects which would allow it to opt in to the Early Opportunities workstream, we foresee that some of these proposals will also be relevant to projects in the PT2030 workstream. On that basis, we would like to set out some considerations below:

Assessment and approval by Ofgem

Anticipatory investments (ie shared offshore transmission assets solutions) need to be assessed and approved by Ofgem ahead of OFTO or shared infrastructure 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 the early stages of projects. Each assessment should result in a clear 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 are very unlikely to proceed.

Assessment and approval by Ofgem should consider the benefits of the anticipatory investment, eg ultimate potential for sizeable cost savings, reduction in infrastructure and environmental and societal impacts etc, against the risk of certain projects not coming forward and the ultimate exposure of the consumer. Assessments will need the lead 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 the HND, or specific concepts such as Quasi-bootstrap, bootstrap or MPIs.

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. As such, we don’t believe attempting to quantify and allocate AI risk and benefits will be meaningful - rather we recommend Ofgem recognise the relatively low level of AI risk and adopt the approach we set out in response to Question 2.

CfD and competition issues

As noted in the consultation, the current CfD processes put competitive pressures on generation projects and create issues for coordination. We encourage Ofgem to coordinate with BEIS regarding potential opportunities for providing some level of flexibility in the CfD contracts to allow for coordination between projects. For example, allowing appropriate relief under the CfD for eg failure to connect, where the more complex sharing of infrastructure leads to later than expected connection caused by circumstances outside of a developer's control.

Also, it has been recognised that 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. Where coordination is being taken forward, developers will still be reliant on other projects securing a viable route to market such as CfD. 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.

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. If 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 need to be developed (an entirely new process to that which is done today).

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. Again, we encourage Ofgem and BEIS to work together in promoting solutions to the abovementioned issues.

How the financial cover for anticipatory investments can work

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.

Existing User Commitment arrangements (CMP192) are used to provide cover before other generators connect. Existing User Commitment arrangements would require 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, ie it has been pointless to ask a generator to provide cover against their own works and costs.

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 respect of 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, and this factor could be adapted for strategic choices in coordinated offshore 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.

It should be noted that in some cases the User Commitment sums may not provide an appropriate level of financial cover for a shared infrastructure scenario with two or more connectees, eg 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.

Focus on generator benefits in relation to risk apportionment

In several parts of the main text and in Appendix 1 of the consultation, Ofgem makes it clear that, when assessing which parties take the risk with anticipatory investments, it will assess the benefit that generators receive from the anticipatory investment. 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.

As noted above, this should not be a focus of the assessment by Ofgem because it risks ignoring the 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 all of the objectives put in place, ultimately to assist in achieving net zero in the most economic and efficient manner.

Level playing field

In several places, eg 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

For any pathfinder projects, we would like to highlight that where shared connections require new cable corridors, these will certainly require new consents. Submitting an application to amend an existing consent, or indeed submitting an application for a new consent would be a long, costly, inefficient process, that could take many years to complete, particularly where a new environmental assessment is required. Such a scenario would undoubtedly have a significant impact on our ability to deliver on net zero.

Question 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?

As noted in our response to Question 2, it is important to contextualise AI for offshore wind and transmission and recognise the relatively low level of associated risk. Taking the approach, we set out in Question 2 identifies the issues required to mitigate remaining AI risk. We believe setting out to determine how to share AI risk between consumers and developers is a pointless task in itself and not an appropriate objective for an SCR. Instead based on our response to Question 2, the objective of an SCR should be to put in place further mitigating factors to further reduce AI risk to an appropriate level for consumers, as part of this objective resolving pre-requisite issues. We believe an SCR with this more meaningful objective is essential and required as soon as possible and should therefore deliver solutions that work for PT2030 and, where required, Early Opportunities.

Timely implementation of the SCR necessitates the scope of reforms to be the minimum and simplest approaches required to facilitate shared offshore transmission solutions where they are identified in the HND recognising more considered and perfected approaches will be implemented via the enduring coordination regime. We suggest the following approach to a consolidated Early Opportunities/PT2030 SCR:

- The SCR should identify aspects of the regulatory regime in relation to shared offshore transmission assets that are necessary to clarify for offshore wind generators which we believe would comprise:
  - codification of the shared asset solutions in chapter 2 of the consultation and importantly for all solutions identifying shared and sole use assets and the boundary between them;
  - a method for socialising and recovering the costs of these transmission assets through TNUOS, likely using the same approach for onshore assets;
  - developing a form of user commitment to be applied to shared offshore transmission assets based on CMP192;
  - developing Ofgem's cost assessment and approvals process for coordinated shared asset solutions; and
  - sufficient and proportionate liabilities for timely delivery of the transmission assets.
- To simplify matters, the default approach could be to translate current onshore rules (for the shortlisted issues) to the offshore regime where applicable and, where not applicable, to implement the most minimal changes required to onshore rules to adapt them for offshore.
- Ofgem should aim to finalise the above in respect of the SCR in advance of the its launch.
- The SCR should be implemented by an Ofgem direction to the ESO comprising a finite and simple set of reforms, eg translating the onshore approach which can be implemented in minimal time given previous Ofgem consultation.

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

We have no comments in relation to the proposed approach to deliver objectives of the Early Opportunities workstream except that any models devised should not give certain generators undue advantages in the context of eg CfD allocation rounds.

Pathway to 2030 questions

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.

Yes, if executed and resourced properly, with the right stakeholder input, the holistic network design (HND) can support the delivery of a more coordinated and efficient network through identifying wider network needs, opportunities for shared connections.

We agree with Ofgem's view that 'all network infrastructure (both onshore and offshore) which is necessary to connect projects in scope of Pathways to 2030 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.

However, we would question whether an HND will always drive the most economic and efficient outcome, as this depends on whether an HND can be delivered in practice and whether a design fits with the timescale of individual projects. We are concerned that a HND may not appreciate the overall cost of the project delivery, including consenting processes and innovative technologies. This is not just a concern for the HND but for the whole offshore grid delivery value chain.

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. The 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.

We note that the government is consulting on the Future of the System Operator, and possible functions include "holistic and coordinated (onshore and offshore) network planning". If the System Operator is to have this function, it will also need to work closely with TOs and developers on the delivery of the network.

However, while the holistic design is essential, so will be the detail of the delivery. We are concerned that while the ESO holds the necessary incentives and skillsets covering the full picture required for the HND, they may not be 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 to ensure that a robust and credible design and delivery plan is produced.

Paragraph 3.5 outlines that "we envisage 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 believes the consenting process could be accelerated, reducing the overall time for project delivery. As an active participant in ScotWind, we cannot tolerate delays at these early stages of development if we are to aim for a route to market for these projects by the middle of this decade.

This issue is particularly relevant in Scotland, and therefore ScotWind, where there is an entirely different consenting regime and, in some instances, far less pressure on coastal land use compared with England and Wales. 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.

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 with the development process, currently competition is applied after the windfarm asset is generating so the OFTO tender process is not factored into development timelines.

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.

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?

In the current framework Offshore DND and pre-construction phase works are largely undertaken by developers, as a way of ensuring maximum project optimisation. We believe a DND will be subject to the offshore delivery model chosen for coordination. Therefore, there could be some merit in a detailed network design, if brought in at the correct stage of relevant delivery models.

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 in order to ensure we deliver projects in time.

As highlighted in the HND section, the party that delivers a DND needs to be correctly incentivised to deliver the optimal design, balancing technology maturity, planning risk, cost reduction and environmental constraints.

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. Detailed design is generally developed throughout the consenting process and only finalised with a detailed design at point of construction. Therefore, an overly detailed design (eg 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.

However, a DND is useful for tendering and could be used to allow for competition in the offshore delivery models.

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.

Yes. We agree that the existing developer led model should be retained for radial solutions for offshore zones where one developer is delivering the whole project portfolio or when demonstrated efficient following the principles of offshore coordination.

As indicated previously, we believe that there are currently clear incentives in place for the developers 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, the developer carries the vast majority of the cost of the grid connection (either passed through via TNUoS or disallowed if Ofgem deem it inefficient), and most importantly the grid connection is required for the project to be connected. Therefore, without a timely and efficient grid connection the windfarm cannot earn revenue or be competitive when trying to provide a cost-effective solution that brings benefits to consumers. In this context a developer-led approach, if selected, should still deliver an optimal offshore grid.

We want to 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.

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[1] 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.

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.

We believe that any of the delivery options could be contemplated as long as there is enough certainty that the parties responsible can deliver within the timeframes of Pathways of 2030 workstream. It's expected that the HND will provide the least regrets options for the coordinated approach of infrastructure, and out of that assessment, parties required to coordinate will need to assess their options for delivery trying to minimise risk and costs. Therefore, Offshore delivery options can be subject to the decision of the relevant stakeholders involved in a coordinated area, as long as they follow the principles of the HND.

The UK has demonstrated to be a world leader on delivering offshore infrastructure for the past few years, with the right level of expertise across the whole sector. However, we believe it's not a matter of expertise but mostly about having the right incentives to progress on a timely basis, particularly around consents for network infrastructure. Developers are significantly exposed to liquidated damages and connection liabilities, without mentioning timeframes for qualification to CfDs, which make them strongly incentivised to secure consents for all necessary offshore infrastructure. Placing responsibility of consents on any other third party need to come with a proper incentivisation framework that reduces the likelihood of adding further risk to OWF developers.

Similarly, the delivery of timely grid connections should follow the same principle. Once consents are achieved, connections become the next critical path for developers as the risk of delays can translate into further option payments under leasing arrangements, and late delivery penalties included in the CfD contract. We believe these sources of risk; specifically, timely delivery of shared offshore transmission infrastructure should be discussed between Ofgem and relevant parties (BEIS and CES) for areas in which coordination is to be promoted out of the HND. Allowing for more flexibility on these aspects will work in favour of finding successful ways of coordination without unintentionally and unfairly leaving most of the risk to generators.

Changes on Legislation for Offshore Deliver Models

It is important that the assessment of the need for changes to legislation around any Offshore Delivery Model(s) proposed is not just restricted to "electricity regulation" matters. Ofgem, along with BEIS, should also look to arrange for an assessment of wider relevant legislation, eg planning law, and the provisions of the 1989 Act which govern compulsory acquisition of

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

rights. Furthermore, this may follow that changes to Scots law is required, and so discussions with the Scottish Government are required and a review of relevant Scottish legislation is essential.

Timings for ScotWind

We encourage Ofgem to make, with urgency, the appropriate changes to the models that are best suited to deliver the 2030 targets. However, we believe parties should be allowed to commence work ahead of the changes being implemented with a level of comfort provided by Ofgem (which should provide a clear steer on the following), eg on expenditure and cost recovery. Notably:

- Boundaries between shared and sole use transmission assets;
- Application of user commitment to shared assets, for connecting generators including cost allocation between them;
- recovery of shared offshore transmission asset costs ie to be socialised across all network users via TNUoS.

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 rely upon it immediately, with the intention that parties have a good understanding of the detailed designs to the end of 2022. This should not be hampered by having to wait for regulatory framework changes to be put in place. Ofgem should set a clear minded-to position on the changes required by early 2022, followed by NGESO quickly driving changes and implementing Ofgem's required position. For this purpose, we believe that Ofgem, and particularly NGESO, should be resourced appropriately to keep the necessary pace that the industry needs.

Considerations on the Delivery Models

We would like to highlight the following considerations around the Offshore delivery options presented in this consultation:

- **Option 1 – TO build and Operate:** although we recognise this option doesn't open competition in offshore networks, we believe existing TOs in GB have some track record of capabilities delivering offshore infrastructure such as the Western Link HVDC. However, it is clear that TOs will need to be resourced appropriately if they were to be significantly involved in Option 1, as this represents a significant addition to their existing obligations on top of the RIIO-2 price control, which is already posing a challenge for work and investment on the onshore transmission system. If Option 1 goes ahead, there should be a clear plan for resourcing TOs for such a task.

- **Option 2 – TO design, consent, build (OFTO operates):** this model resembles the existing Generator led model with the difference of having the incumbent TO running the process until the transfer to an OFTO. Although we believe this option could replicate a well-established and efficient model, we believe the TOs should be provided with the right incentives to build efficient and economic assets for generators in line with their required timescales. This would require a transparent and clear asset valuation process that runs in parallel to construction ensuring that this does not create another potential source of connection delay which generators could be penalised for.

- **Option 3 – TO design, OFTO build and Operate:** we believe Option 3 represents a good middle ground option that will allow OFTOs and potential 3rd parties to get involved in construction. We believe this is necessary for improving the overall industry's capabilities and services when moving towards the Enduring Regime but should always be subject to the readiness of the OFTO market to embrace the responsibility. We recognise that, although t the original intention of the OFTO regime, no OFTO owners operating infrastructure in GB have relevant construction credentials to date. However, we understand that if Pathways to 2030 projects are not open to competition, that will just leave a very limited headroom for offshore competition in the Enduring Regime. As per Option 2, we believe that Option 3 requires new incentives on both the TOs and OFTOs to ensure there is an economic, efficient and timeous delivery of design, creating a framework that encourages a common understanding and agreement of the infrastructure required. We also want to highlight that given the involvement of 3 parties in the process, warranties and liabilities would need to be considered to share the risk of connection delays and the potential penalisation to the generators.

- **Option 4 – Early OFTO Competition:** We believe there is a risk that the tender process could delay delivery seeing it harder to run in parallel to the delivery process. Under this option 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. This is also commented on in question 13.

- **Option 5 – Very Early OFTO Competition:** although this model would likely allow for more competition and innovation, we are concerned about how this option could be put in place on time to progress connections within the Pathways to 2030 workstream. We believe that allowing for very early competition could create inevitable delays to the process, when procuring and assessing the range of options presented by OFTOs.

- **Option 6 – Generator Build:** This option is well established and involves competition. The developers are experienced and resourced to undertake the necessary work, and the process is known such that delays can be minimised through DND or OFTO tendering. It is worth noting that developers may not wish to take on the construction risk associated with wider offshore transmission infrastructure that is identified in the HND and that there is no incentive for them to do so. The liability position as between the "lead" generator and the later generators would have to be considered. They may be also an aversion for developers to see other competitors undertaking these wider works on behalf of the coordinated projects. 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. This model raises questions over what happens when a developer undertaking offshore transmission work (for others) changes their generation project plans, is not successful in securing a route to market or terminates the project altogether. It also raises issues with regard to Planning/consenting and land rights. This involves a generator/ developer seeking consents for a transmission network that is not solely required for its own generation station. This will create complications for any approvals. As an example, so far as compulsory acquisition under the 1989 Act is concerned, use of powers may encounter issues, as the power would not be being used solely for the generator's project. For this reason, we propose other potential options in Question 13.

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

ScottishPower supports the following additional models that are being proposed by industry and allow for flexibility. As discussed in question 12, we believe that a blended approach could be considered for Pathways to 2030, or an approach that chose a delivery model on a project-by-project basis. This will allow the industry to produce a learning curve of approaches that may help to design the Enduring Regime while ensuring 2030 targets are met.

Developer joint venture

A developer joint venture might be attractive where wider and shared transmission infrastructure is ultimately needed by a number of developers (at an equivalent stage of development) but no one developer wishes to take on the works in isolation. This could offer a developer led detailed design route for delivery of all the necessary offshore transmission infrastructure with OFTOs being introduced at point of pre-construction or operation. 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 or Offshore generator(s) / JV	OFTO	OFTO

Third party models

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 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. However, we believe that for this case, the DND must be agreed with the relevant OWF developers before hand-over to the construction party in order to avoid any issues at that stage. 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

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 (eg IC-led and OFTO-led) or just one? What factors influence your answer?

In the short term MPI's may allow the connection of offshore renewable power to be combined with the ability to allow power flow into constrained markets, but a structured plan to deploy these resources to optimise asset build and future cannibalisation is required. We agree in the short-term that IC-led and OFTO-led models could both be models to be utilised, minimising onshore connection points and reducing assets deployed.

For the medium to long-term the offshore grid should be centrally planned by an ISO and strategically developed to optimise the assets deployed, target the right connections with neighbouring European states and to minimise the number of onshore connection points to GB and enabling large scale, long duration storage to be strategically planned. To achieve this, the model needs to be adapted to allow for multiple license holders within the connected network. In this arrangement, the points of interconnection with neighbouring markets should be evaluated more on their ability to provide a service to the UK, in terms of improved security of supply and/or the ability to provide essential system services rather than primarily on arbitrage benefits. The best way of achieving this would be for connections within the network auctioned through a competitively run build and ownership model. The system operator identifies the need case and runs an auction process with a guaranteed annual revenue stream over the lifetime of the asset ideally 40years+ but no less than 25 years. The key performance measurement would be the interconnectors availability not the MWh's transmitted.

The offshore grid should be operated by the national ISO's where owners are incentivised mainly on availability of assets which can then be used dynamically to achieve the best outcome for their home markets and allows for uncertainties in the evolution of the generation mix to be managed over the operational life, this model also decouples generator and transmission risks, allocating them where they can best be managed.

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. 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).

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.

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

Until legislation and the licensing regime can be changed it might be necessary to have multiple owners but regulations should not be a barrier to the future structure of the market, extending some of the principles from the onshore network and moving to an annual revenue stream model for offshore assets could help asset classification so that whilst the offshore grid will have multiple purposes in the future, consideration could be given to amending legislation to create a single asset class. The availability of system data, the rigorous application of ringfencing, central operation by an independent system operator and a revenue mechanism linked to an annual revenue stream model could simplify the structure of the emerging network for all parties.

Question 16: What are the commercial, operational and regulatory factors that would drive a developer's 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?

The key element in attracting investment and providing certainty to the offshore renewable industry is certainly on grid connection date. For MPI projects, from a developer's perspective, this must be the primary consideration to allow coordination with other investors. Failure to deliver could have consequences for investor confidence for future developments, therefore the assets that couple the generator to the home market in either scenario should be prioritised. The most effective system operation model for an offshore transmission network connecting renewable generators, would be one where the offshore grid is centrally planned and strategically developed to optimise the number of assets deployed in connecting with neighbouring European states. In this arrangement, the points of interconnection with neighbouring markets should be evaluated more on their ability to provide a service to the UK, in terms of improved security of supply and/or the ability to provide essential system services. Interconnection capacity should not be the primary purpose and evaluation should not be solely based on arbitrage benefits. It's important to recognise that the assets required by the generator to get their power to market should not be subject to the interconnector restriction to make 70% availability for trading. To make the most of power generated from renewable sources, offshore wind developments should have unrestricted access to their home market, any curtailed generation due to onshore restrictions should be stored or redirected at no detriment to the developer.

Attracting private investment to construct and own these offshore assets will be key in delivering value for money to bill payers and making the transition to them an affordable proposition. Private ownership of offshore transmission networks should be coupled with the day to day operation and dispatch of these assets being carried out by the national system operators. This will likely ensure the most effective utilisation and lowest overall system operating costs.

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.

As per question 16.

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?

Codes need to be amended as required to meet the needs of users and a future interconnected system with multiple asset owners if it's to provide best value for all stakeholders.

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?

It is difficult to predict the exact use of an MPI asset over its lifetime as net zero futures will require extensive change to the power system as we have known it over the last 50 years. These assets should be considered as strategic for the security of the GB system and as such should be centrally planned and considered for development following an assessment of national requirements and a comprehensive needs case. This could include assessments against other options like long duration large scale storage solutions. This assessment should be led by the ESO/FSO involving the relevant stakeholders and European partners. Availability of strategic assets is the key consideration and whilst parts of the system is down for maintenance or non-planned outages from time to time the availability should be considered in line with the technology being deployed and move towards performance levels associated with comparable onshore assets over time. Retention of a time of year outage availability weighting system would be preferable for assets directly connected to windfarms.

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?

We cannot identify any particular issue in "transposing" conditions from one licence to another, at a high level. Section 7 of the 1989 Act contemplates substantial flexibility as to the conditions that can be included in a licence. Transposing of one licence to another should be carried out as required to meet the needs of the interconnected system and remove any restrictions surrounding their ability to provide improved security of supply to the GB without restriction.

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?

We believe the exemption provision with the Act removes the required need to define an assets primary use when defining interconnector or OFTO (eg 70% interconnector requirements) and allows for the asset to be prioritised for GB system supply and security.

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?

Offshore windfarms are developed on the basis of a clear understanding of access rights and likely export levels, and any changes to the surrounding network must not result in an adverse alteration of such rights and reduction of expected export levels.

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? (eg 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

The UK is creating a world leading offshore wind industry and this early momentum must not be lost in any changes that take place in the future. Decarbonisation of the economy is not an easy challenge and it is important that we deploy sufficient MWs of capacity to meet our future aspirations.

Efficient transmission systems are key to ensuring that as much power is harnessed and that it is transported to either end users or storage facilities that have the capability to time shift it to cater for the lower outputs from the renewable generators. Developing a system that encourages private investment into these different areas is fundamental to the success of the energy transition.

[In the long term] we believe the most effective system operation model for a highly integrated offshore transmission network connecting renewable generators with MPI's, would be one where the offshore grid is centrally planned and strategically developed to optimise the number of assets deployed in connecting with neighbouring European states.

In this arrangement, the points of interconnection with neighbouring markets should be evaluated more on their ability to provide a service to the UK, in terms of improved security of supply and/or the ability to provide essential system services than primarily on arbitrage benefits.

Once identified, the project should be competitively tendered or be subject to a cost assessment process for construction and ownership over a typical operational asset life of the technology deployed, thus ensuring the lowest possible cost for UK consumers and intergenerational sharing of the benefits. As has been seen in the UK and other countries, applying an open market test to offshore asset deployment can result in consumer savings, and centralised planning under an ISO could minimise the deployment of duplicate assets that might otherwise result in higher costs and stranded assets in future.

Due to the inherent uncertainties that come with a shift to a very high penetration of intermittent renewable generation on the system, investment will best be secured through offering an annual revenue stream model linked to the availability of the asset.

This would allow the ISO to manage the operation of the asset to trade energy and services across the link without reference to the asset owner, potentially providing more open access than the current cap and floor model. The day to day operation of the links for dispatch and balancing would also be carried out by the FSO within the agreed asset operating limits, and the transmission owner would be responsible for routine and corrective maintenance.

Continuing with a cap and floor regime could risk a situation where several interconnectors have low annual energy flows and result in floor payments being made on a regular basis - a situation which is good for neither bill payers nor investors. In contrast, a regulated revenue stream can be set to reflect the efficiently incurred costs of constructing and operating the MPI and provide assurance to connecting parties that the MPI developer has sufficient incentive to build and commission the transmission assets to the required timescales and standards.

As the network with in GB and Europe transition to a system with high RES penetration and less commercially viable fossil fuel stations then it is feasible that the interconnectors will remain unconstrained assets in practice and may become less able to provide security of supply to the GB or European markets at times of low wind. Therefore, a regulatory and commercial framework needs to be to identify for strategic large-scale long duration storage assets in order to attract private investment that incentives them to construct and own them.

ScottishPower
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