codling wind park
PROJECT DELIVERY TEAM

17 January 2014

Matthew Grant
European Electricity Transmission
9 Millbank,
London
0207 901 7000
ITPRMailbox@ofgem.gov.uk

Dear Matthew,

REGULATION OF TRANSMISSION CONNECTING NON-GB GENERATION TO THE GB TRANSMISSION SYSTEM

Fred. Olsen Renewables Ltd and Hazel Shore Limited as joint venture partners in the development of Codling Wind Park (CWP) welcome the opportunity to respond to this important consultation. Codling Wind Park is a consented offshore wind farm in Irish waters with a 1GW signed connection offer to the GB network in Wales. As such, we are a key stakeholder in this area.

We fully understand the wide-ranging considerations you have been asked to balance in determining an appropriate approach to regulating the connection of non-GB generation assets. In particular, we recognise there will be trade offs between facilitation of near term investments by developers and the long term strategic goals of greater cross border trading, cost efficiency and security of supply. We believe that, in order for such benefits to be realised in the medium to long term, it is vital that the the supporting regulatory frameworks put in place today support the near term investment decisions that allow such projects to be built for 2020 but also enable adaptation of the rules in the future. Longer term goals will not be realised unless the immediate requirements of the catalysing agents such as CWP are given due consideration in the design and timing of introduction of any framework.

Accordingly, our response sets out the following key points:

1. Immediate priority needs to be given to ensuring dovetailing between the OFGEM process, including the timing and substance of decisions, with the development of the Inter-governmental agreement;
2. To ensure delivery of projects by 2020, the regulatory approach needs to be based on tested working practices and it must be evolutionary. It needs to take full account of, and underpin, those factors that make such projects financeable and economically viable. These dual imperatives point to adoption of a staged approach. This should be based on utilising existing instruments at the outset but with clear commitments made by regulatory authorities to a set of guiding principles determining how these instruments will be adapted over time to achieve the best outcome;
3. Emphasis also needs to be placed on creating a level playing field in the commercial treatment between GB offshore and non-GB offshore generation projects, but recognising the scope for differences in the form of rules and regulation that will exist between the two;

4. Hence, in our view the only really viable framework would be focussed on:
    a. a 'Direct and Exclusive' asset configuration, underpinned by an interconnector licence with exemptions;
    b. It should be supported by a commitment to create a viable cap and floor revenue and cost recovery model (with consumer underpinning) for the eventual owners of interconnection assets, including an element of a fair infrastrurcture charging for the non GB generator,relfecting similar TNUoS charges levied on GB offshore generators subject to OFTO connections;[1]
    c. It should be accompanied by a commitment to standards that will build confidence that the commercial interests of the owners of generation will not be compromised by future, strategic, regulatory development; and
    d. The implementation of the model should then follow rapidly, with detailled draft rules and regulations available before the end of 2014.

We believe this model has significant distinct advantages. Most immediately it would assist the timing of project delivery for achievement of 2020 targets; and it would also form a stepping stone to the creation of an enduring and cost effective framework to allow for the delivery of further non-GB generation projects and greater market interconnectivity in the future.

An inherent feature of this approach is that it necessitates setting in place an initial regulatory framework in advance of completing detailed work on a comprehensive coordinated approach to GB and Irish market interconnection. It therefore cannot claim to be a comprehensive or complete solution for any eventual strategy developed between the two governments and the two regulatory authorities. It is a meaningful staging post that may need further regulatory interventions in the future to refine and adapt the framework if and when more strategic decisions are made. Under our proposal the flexibility to make future adaptations to regulations will be fettered as we expressly set out a prevailing need to grandfather the commercial expectations of stakeholders who came forward under the original framework. However, in our view these are necessary and reasonable compromises, taking into account the catalysing role developments like CWP are playing in facilitating the achievement of wider objectives and noting that without taking this approach it is likely that projects like CWP would be unlikely to be delivered by 2020.

To support this model the following needs to be delivered in the short term and certainly during the course of 2014:

1. Publication and finalisation of the Inter Governmental Agreement (IGA) in early 2014;
2. A defined delivery plan for the implementation of the IGA, taking into account the processes and views of the regulators in both jurisdictions in early 2014;

[1] Further consideration may need to be given to how the costs of underpinning this scheme might be shared between GB and Irish markets which is a determination that falls within the remit of the relevant governments and regulatory authorities when they consider the terms of the Inter governmental agreement and associated regulatory arrangements. It also may depend on the prospectus for interconnector use.

3. In early 2014, synchronous agreement on the regulatory treatment of transmission assets by regulators in both jurisdictions in early 2014 and a decision on the choice of legislative framework route capable of supporting pre-2020 investments. This would be accompanied by a delivery plan and statement of principles that will guide further development of the regulatory framework, and build confidence amongst developers and investors;
4. Publication of draft regulations and ancillary documents (synchronising with any proposed code modifications) before the end of 2014;
5. Final determination by the Department of Energy and Climate Change (DECC) confirming the Eligibility of non GB(?) generation for low carbon support, in early 2014; and
6. Detailed drafting development for the CfD as applied to non GB generation by Autumn 2014 summer/early 2014 (before CfD allocation rounds begin).

We further explain our rationale behind our suggested approach through our answers to your questions in the attachment to this letter.

We look forward to discussing these further with you in due course.

Yours sincerely

Nick Emery
Director

Codling Wind Park Limited
2nd Floor
64-65 Vincent Square
London SWP 2NU

codling wind park
PROJECT DELIVERY TEAM

ANSWERS TO CONSULTATION QUESTIONS

CHAPTER 1

Question 1: *What are the key milestones for the delivery of non-GB generation and connections pre-2020? How does the decision on the regulation and licensing of non-GB connection fit into this timeline?*

There are two aspects to consider – milestones related to the government, regulatory and legislative horizons and critical path milestones at the project level. Both are intrinsically linked by the requirement for sufficient regulatory certainty to be in place to support a ramp up in project level investment.

Regulatory, Government and Legislative Milestones:

In the first instance, the immediate priority will be to ensure that the OFGEM process reflects and dovetails with the intent and spirit of the IGA being developed by the UK and Irish governments. In January 2013 the UK and Irish governments signed a Memorandum of Understanding (MoU) to evaluate the case for trading renewable between the two countries. The trading would involve the physical export of electricity from renewable sources from Ireland to the UK. It is essential that the MOU timetable and work programme are delivered as soon as possible. In particular, the scope and level of detail of the subsequent IGA is of key importance. The associated regulatory framework will need to both facilitate and support the objectives of the IGA. As such, it is important that the Regulatory Authorities in both jurisdictions work closely together and provide advice to their respective governments as part of the IGA process, with a focus on arrangements that are available now, rather than waiting for its outcome. This will prevent inadvertent barriers arising to delivery of the required outcomes and ensure that the overall timetable is as efficient as possible.

Turning to the specific question of defining the substance and timing of the regulatory approach it is important to note that CWP fully supports the goal of delivering greater coordination and wider use of connection assets for non-GB generation,where appropriate. However, if there is a serious intent to facilitate the completion of projects like CWP before 2020 then the approach adopted by OFGEM and other stakeholders must be pragmatic and should be designed around three key considerations:

1) **Evolutionary and staged, not revolutionary**:

The priority should be adaptation of existing, well understood frameworks to facilitate longer term strategic interconnection aims, but not to the detriment of delivering the transmission and connection requirements of near term generation projects. Approaches involving the creation of new institutions, new legislation together with supporting codes and regulations, and/or protracted procurement processes should be rejected. These would take time to design and implement and could add considerable complexity and uncertainty to an already cluttered regulatory landscape.

2) **Aligned with the commercial necessity of generators to build and energise prior to 2020:**

In our view, an approach which seeks to design and implement a full regulatory framework to cover an extensive offshore network capable of facilitating market-to-market trading, and/or the multiple connection of non-GB assets would take several years to deliver. Success would depend on an extensive and wide-ranging regulatory work programme. OFGEM has rightly ring fenced the Irish export element from the ITPR Project in recognition that there are real difficulties facing projects which need to deliver before 2020. The risk of delay to delivery is now the critical consideration and the ability to support projects wishing to build and connect before 2020 is a key driver behind the Intergovernmental Agreement (IGA). Any approach should be cognisant of the paramount importance of ensuring that developers who are ready to build generation assets by 2020 are given the best opportunity to do so.

3) **Capable of providing investment certainty**:

The practical issues associated with delivering connection with market-to-market flows, multiple users or GB balancing capability as well as transmission to the orginal 'genesis' generation projects should not be underestimated. It is crucial that early certainty is offered around the suppoting institutional and regulatory arrangements so that physical transmission assets will be available to allow projects to get their power to market, and that there is confidence amongst investors to provide the necessary capital to achieve this.

Investors will be very concerned that projects such as CWP will be able to recover the costs of any anticipatory build-out and/or any further incremental investment associated with facilitating multiple use of connections in a manner that is economically viable. They will also want to be confident operationally that generation assets are not stranded at considerable financial risk. These are fundamental considerations in the assessment of any business case. It is debatable whether CWP could raise the necessary finance if there were material doubts on these matters.

In summary, we believe that a satisfactory regulatory framework will *eventually* be able to be put in place for the more complex arrangements (transition to full interconnection, GB system reinforcement, multi-purpose assets under different asset configurations). However, this is an unavoidably complex issue and will require Ofgem (as well as their Irish Counterparts) and perhaps the UK and Irish governments to consult, analyse and consider the issues in detail and at length. The scale and scope of work involved is on a par with,if not greater than the development of the OFTO regime which has taken many years to develop to a stage where the investment community are comfortable with it. Taking a such an approach to non GB generation will not provide the required investment certainty for projects which wish to deliver before 2020.

In order to ensure that both investment and government objectives are facilitated, the following should be adopted.

1. **Direct & Exclusive asset configuration (at the outset)**: These would be direct and exclusive connections, albeit they may involve an element of anticipatory investment to countenance future strategic development of the connection into an interconnector. In the case of CWP the cable capacity will most likely be 1GW, and with a 40% capacity factor it is likely that for the majority of the

time there will always be an element of spare capacity for use in auction on the interconnector. As a result the levels of anticipatory or incremental investments would relate to onward connection to the Irish network. We do not believe developers should be obliged to make anticipatory investments, where the risk of that investment falls on the developer, and hence they should be able to opt-out of doing so if they are not comfortable that the commitment from the regulator to key principles (see 3. below) is not sufficiently strong enough. Assuming confidence exists, over time, the exclusive connection could be utilised as an interconnector and this would be the premise but in our view this would depend on the translation of the principles described in point 3 into regulatory substance under point 4.

2. **Interconnector Licence (with exemptions)**: Regardless of essentially being configured as 'Direct & Exclusive' at the outset, projects ready to commission by 2020 should be allowed to connect through a GB Interconnector Licence (with exemptions). This approach would not necessitate moving outside the bounds of existing and well understood legal frameworks, or require new legislation or protracted due process and hence would allow for the timeliest progression for projects like CWP. We accept that this will involve an investment of time and resource into seeking the appropriate exemptions from the EU for New Interconnection in accordance with Article 17, parts a) to f) of the Electricity Regulation (EC) 714/2009 and Article 36 of the Gas Directive 2009/73/EC. Exemptions may need to be procured in particular for Third Party Access, Use of Revenues and potentially Unbundling provisions. On balance, this is far more manageable and lesser timing risk than those associated with other delivery routes set out in the consultation as it amounts to the completion of governance, rather than a design process. On a prema facie[2] basis CWP and OFGEM and the CER should have reasonable arguments to present regarding satisfaction of certain of the exemption conditions. Under our approach, whilst being Interconnectors in name, the connections would in essence behave as radial transmission connections until such time as OFGEM has determined and implemented the appropriate regulatory framework to secure shared long term strategic aims.

3. **An unambiguous Statement of Principles as a foundation for further regulatory development**: Recognising the incompatibility of delivering a final regulatory framework in time for CWP to build and commission by 2020, the transitional signals at the outset would be made public in the form of a 'Statement of Principles' which OFGEM would commit to adhere to in establishing the detailed regulatory framework in due course. These could include stating a desired ultimate objective of flexibility for use by other non-GB assets or non-GB markets but in any event would be qualified by the regard to the following three critical principles should they choose to take this route:

   a. Investor certainty: Commitment to deliver an investable revenue model for any future interconnection, allowing for CWP to appropriately recover costs of connection/transmission asset development in an economically efficient manner, commensurate to GB offshore generators**.** Even in the absence of a strategic or coordinated offshore model CWP would need to know that they can recover the full costs of development of the connection through a viable sale to an Interconnector operator if this is demanded of them over time, or if this is the commercial

[2] Without having conducted detailed legal due diligence on this point at this stage. We would welcome working in partnership with OFGEM to explore this further.

route CWP wish to undertake to make their project economically viable. A commitment from OFGEM would need to be made to include regulatory underpinning for the revenue flows (through an appropriate Cap and Floor approach if ultimately it was intended for interconnectors to be subject to private ownership, or through a Fixed Revenue model for TOs if deemed appropriate) for eventual use as an Interconnector. This could be based on an assessment by one or both of the regulatory authorities[3] (as per OFGEMs assessment under the OFTO process) of the efficient level of costs incurred in delivering the project, given the information available to the developer at the outset. Following this assessment, a floor or guarantee would be put in place to support the required OFTO revenue. Under normal circumstances, this revenue would be provided by the generation project or (if evolved) other eventual users of the interconnector. However, in exceptional circumstances it would afford the same protection to the transmission asset owner as that given under the OFTO regime. The benefits of providing this guarantee would be a substantially de-risked project profile which brought risks within acceptable limits for the developer (and hence lowered risk adjusted costs) and provided a more cost effective solution for consumers. Without this, non-GB offshore generation projects are discriminated against and disadvantaged relative to GB offshore projects that are able to take advantage of the regulatory guarantees under the established OFTO scheme.

b. Clear risk allocation and compensation provisions for different users of the connection, including the generation assets.

c. A transparent and viable process for reserving capacity on the connection for export of power from the ‘genesis’ generation assets based on physical notification of requirements, and return of surplus capacity to the interconnector operator for auctioning.

4. **Clear Delivery Plan, with considerable detail emerging during 2014:** Accompanying the ‘Statement of Principles’ OFGEM should set out a delivery plan, including a break down of steps and timings that they would follow to release further detail and decisions on the development of the enduring regulation.. From CWPs perspective, to deliver by 2020, it would be essential that a draft final framework of regulations was published before the end of 2014 so we and our investors can maintain confidence in making the substantial investments that are on the imminent horizon (see ‘Related Project Milestones’ below).

Hence in summary, the following needs to be delivered in the short term and certainly during the course of 2014:

1. Publication and finalisation of the IGA in early 2014;
2. A defined delivery plan for the implementation of the IGA, taking into account the processes and views of the regulators in both jurisdictions in early 2014;
3. In early 2014, synchronous agreement on the regulatory treatment of transmission assets by regulators in both jurisdictions in early 2014 and a decision on the choice of legislative framework route capable of supporting pre-2020 investments. This would be accompanied by a delivery plan

[3] Depending on the terms agreed as part of any IGA or between the regulatory authorities as part of a coordinated process.

and statement of principles that will guide further development of the regulatory framework, and build confidence amongst developers and investors;

4. Publication of draft regulations and ancillary documents (synchronising with any proposed code modifications) before the end of 2014;
5. Final determination by the Department of Energy and Climate Change (DECC) confirming the Eligibility of non GB generation for low carbon support, in early 2014; and
6. Detailed drafting development for the CfD as applied to non GB generation by Autumn 2014 summer/early 2014 (before CfD allocation rounds begin).

The achievement of these milestones relies heavily on efficient working between governments and different regulatory authorities.

Related Project level Milestones:

At the project level, large scale offshore generation such as CWP must progress through a series of critical phases, each unlocking increasing sums of investment, in order to be built for 2020. Without certainty on the applicable regulatory framework and licencing regime for non-GB connection during 2014 it is likely that CWP will very rapidly be exposed to unacceptable risks of investment losses and/or costs of delay which will be delay the building of the project beyond 2020, and even expose it to the risk of termination.

The initial stages of offshore development, such as gaining planning approval, entering into option agreements, and engagement with National Grid regarding connections to the Transmission system - are high risk investments. This is as the result of the uncertainty about ultimate delivery. CWP is advantageously placed having navigated much of the consenting routes. It secured planning permission for up to 220 turbines (with a further 200 turbines in the consenting process), it signed in December 2012 a 1GW connection offer from National Grid Electricity Trading (NGET) for connection into the GB network through Wales; the Irish government Minister for Communications, Marine and Natural Resources in the granted a foreshore lease on 15th November 2005, valid for a term of 99 years.

The investors have spent many millions of pounds in reaching this point, which is a material sum of money in its own right. Such investments have not been made lightly and have entailed a significant degree of exposure to risk of losses if, ultimately, the regulation and licensing frameworks for non-GB connections (amongst other items of developer risk) do not support the raising and investment of additional funds to complete the development of the project.

In order to maintain a completion schedule by 2020, we now face an imminent step change in the level of investment, but without any directly proportionate reduction in risk or access to cheaper financing. This is as a result of the long lead time of certain procurement processes, and the requirement to put down significant collateral payments to secure capacity. For example, CWP would be expected to place orders for export cables in 2015 with deposit costs for securing delivery in excess of £100m to be made in 2015. In advance and in addition, there is a range of further expense of preparatory works that will need to be incurred in 2014 to facilitate the deposit payment at this juncture, including securing further consents, conducting ecology studies, securing way leaves, geotechnical and geophysical surveys

Clearly, no procurement decision or investment of this magnitude can or should be made in advance of:

a. Understanding the legal basis of CWP's route to the GB network and the resultant costs and operating parameters that relate to that;
b. Understanding whether the technical design of the transmission solution is compatible with the emerging regulatory framework (for example, there will be different technical specifications if the framework demands readiness for interconnection from the outset, rather than later on);
c. Whether the principles likely to guide risk allocation under the emerging supporting regulatory framework is capable of supporting further investments in the completion of the project; or
d. Whether the framework's content and delivery timetable is compatible with the demands and support available under the CfD (see response to question 2).

Hence, timings are very tight if CWP is to build out for 2020. In our view it is critical that the milestones we identified in the Government, Regulatory and Legislative section are met with the necessary degree of commitment from the key stakeholders to ensure this happens.

Without this type of approach we rapidly reach a tipping point where the risk of lower than anticipated investment returns as a result of uncertainty outweighs the commercial imperatives to continue developing the project. In those circumstances we will be compelled to delay decisions or even mothball or postpone project development. Delay is not without financial consequence, not least because it exposes CWP to uncertainty on budget allocation under the Levy Control Framework (LCF) and uncertainty regarding the Strike Price support it might receive under a CfD, particularly as there is currently no visibility with regard to the LCF settlement or strike prices beyond 2020.

Question 2: *From the perspective of a non-GB project developer, how does the decision on the regulatory arrangements interact with Government decisions on renewable support (such as the award of a Contract for Difference (CfD))?*

The decision on regulatory arrangements is absolutely critical, particularly with regard to ensuring the appropriate interaction with the CfD can be designed into the scheme to accommodate CWP. The principle interactions between the process for determining the regulatory framework for non-GB generation and the CfD pertain to eligibility, penalties for late delivery and the adequacy of the Strike Price.

Eligibility:

The existing published eligibility criteria (currently the subject of consultation by DECC[4]) for offshore projects do not make specific allowance for non-GB connections and in particular the idiosyncrasies of non-standard (from a GB perspective) lease and planning consents. DECC needs to be developing these urgently as an explicit green light for CWP to have confidence in being able to participate in the CfD regime.

However, on the assumption that non-GB generators can achieve the same standard of evidence pertaining to equivalent consenting milestones, incorporation and technology eligibility then the differences in any bespoke criteria are likely to be semantic only and should not in principal impact on National Grid's ability to treat effectively with developers of non-GB offshore plant. Specifically, CWP is an incorporated company, with consented, offshore plant, that enjoys a signed connection offer with National Grid.

Assuming DECC confirm their approach to non-GB offshore generation seeking connection to the GB networks then there are no obvious interface issues between CfD eligibility and the timing and nature of regulatory decisions relating to the connection of non-GB generation. The material interface issues for CWP might arise once the project has received a CfD and we set these out below.

Penalties for late delivery:

Prospective non-GB offshore generators like CWP may be significantly prejudiced in their ability to conform with contractual obligations placed upon them to meet certain milestones under the CfD, which may see them exposed to increased risk of CfD termination, or shorter support periods in comparison to prospective GB offshore generators.

Under the CfD, developers will be required to demonstrate substantial commitment to the project by a particular date following contract entry (the 'Milestone Requirement'). Under the latest published proposals[5] the substantial commitment is to be evidenced by the developer demonstrating it has spent

[4]https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/255254/emr_consultation_implementation_proposals.pdf

[5] https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/267735/EMR_-_Update_on_Terms_for_the_Contract_for_Difference_v8.pdf

10 per cent or more of the estimated Total Project Costs, as specified by DECC; or providing evidence of progress towards timely commissioning, such as evidence of an appropriate construction and supply agreements in respect of the facility. The date for satisfying the Milestone Requirement is to be expressed as a date at the end of a given period from entry into the CfD, which will vary by technology but in all cases will be no more than a year after CfD commencement.

Similarly, under the CfD prospective generators will be required to complete their project within a specified window (the Target Commissioning Window) linked to their target commissioning date as provided to National Grid at the point of application. Failure to commission by the outer edge of this window will result in the commencement of the CfD 15 year term, leaving a developer facing less than 15 years support with the reduction proportionate to the extent of the additional time taken to complete after the window closes. Ultimately, developers will face a possible termination under the CfD is they fail to complete the project by a further date, being the Long Stop Date.

CWP will wish to apply for a CfD at the earliest possible opportunity in order to secure certainty of Levy Control Framework (LCF) allocation for the project and certainty of Strike Prices to underpin the investment case, and in particular to support the required down payment on cable. In particular, CWP would ideally want to secure a signed CfD well in advance of placing orders for the cable in 2015, given the magnitude of the associated capital outlay. Under the DECC timetable it should be feasible for CWP to make an application for and to receive a CfD in the autumn of 2014.

However, the counter balancing consideration is the extent to which CWP will feel comfortable in signing up to meet the Milestone Requirement, Target Commissioning Window, Long Stop Date and agreed capacity obligations in the absence of certainty and detail on the enduring licencing and regulatory framework for non-GB connections. It would be commercially unacceptable to face the situation where, having secured a CfD to meet the government's 2020 target, being compelled to make investments to maintain that CfD and the project programme, only then to face the risk of writing off such investments further down the line if the regulatory framework for non-GB connections proved incompatible with the technical solution procured, the financing approach to the project as a whole, or ultimately left CWP at risk of losing the CfD.

In comparison, GB offshore generation will be able to progress their projects on a stable and known regulatory footing relating to connection (through the OFTO regime) and hence face a lesser level of risk under the CfD. Earlier stage offshore developers, pre-OFTO, are not useful benchmarks for arguing that such risks are acceptable and manageable as under the RO scheme there was a far lower degree of revenue and support risk relating to project delay than there is under the CfD.

The disparity between GB and non-GB offshore generation on this issue can only be resolved by either DECC providing non-GB generators with appropriate comfort that penalties will not be applied under the CfD due to regulatory uncertainty on non-GB regulation, or (preferably) OFGEM, together with the UK and Irish governments making a commitment that this 'rock and a hard place' eventuality will not emerge as there will be no delay to making required decisions on the non-GB connection framework.

Without such confidence there is a risk that developers of large, non-GB generation simply do not come forward for a CfD as early as they might, and project delivery dates are pushed back accordingly.

The danger with delay is the degree of uncertainty this creates around access to LCF budget and exposure to the possibility of reduced strike prices under CfDs, noting that currently there is no visibility on the amount available under the LCF, or the level of strike prices beyond 2020.

Settlement Risks:

The CfD will rely heavily on metered volumes under the Balancing & Settlement Code to make payment to CfD generators. As under the CfD, the Boundary Point for metering purposes is considered to be onshore (as opposed to the point of generation as under the RO) then this potentially creates issues for non-GB generators if they are connecting into an interconnector as there could be potential difficulties in distinguishing actual volumes (including allocation of reactive losses) if and when the interconnector adopts multiple users. The obvious solution would be to move the Boundary Point to an offshore meter (at the point of connection into the Interconnector) at the juncture when the connection moves operationally to becoming a network for use by multiple users.

Adequate Strike Price Considerations:

GB developers of offshore generation have typically chosen to take developer led approaches to the construction of the accompanying transmission assets to the onshore grid to ensure quality of the technical solution and control over their project's export date. They have financed the construction of the offshore transmission cable and latterly have recovered the costs and capital associated with this through the sale of an offshore transmission licence through the OFTO scheme, simultaneously ensuring compatibility with the Third Package. In doing so, they do incur a cost of carry in terms of the differential between actual financing costs associated with the bridging capital necessary to build out the transmission link and the assumed financing costs in any OFTO valuation. They may be exposed to unrecoverable capital outlay on transmission as a result of OFGEM disallowing certain items of expenditure in their final valuation of the OFTO licence. But, they are not left needing to recover the fixed costs of transmission link investment over the lifetime of the CfD. The fixed costs of construction are effectively converted into operating cost through TNUoS charges.

The CfD strike price for offshore wind then takes into account the TNUoS charges facing a hypothetical offshore wind generator at the point picked on the supply curve to represent the 'marginal' generator profile that is expected to be brought forward under the CfD. Hence, in generality a competitive project should be able to recover their exposure to the TNUoS charge as result of selling their power with the benefit of the CfD Top-up.

Financiers of and investors in GB offshore developers have developed reasonable confidence in financing the transmission link as shorter term facilities as part of the overall funding package for the offshore development on the understanding that they will be repaid in full, early on. This is because the OFTO scheme has operated effectively in the Transition Rounds and is now a settled and well understood feature of the offshore wind sector. The conversion of a fixed cost into an operating cost attracts lower costs of finance for the OFTO element of construction, and the difference in financing costs between investments of different maturities can be significant in the current financing markets.

Contrast this with the position for CWP as a developer of a non-GB offshore plant, seeking a CfD. As with GB generation our preference would be to undertake a developer led approach to construction of the transmission infrastructure, but most likely with a compelled or voluntary unbundling in time for use as a transmission interconnector. We would then anticipate paying a charge for use of the interconnector of some description. But, until there is a decision and some detail on legal framework, asset configuration and revenue and cost model for the use of connection assets as interconnectors it is simply not possible for CWP to have confidence in whether they would be able to recover the fixed costs of the transmission assets and covert part or all of them into some form of operating cost.

In our view, given the challenges in operating a merchant interconnector, then confidence in achieving a sale is most likely in circumstances where there is a degree of regulatory underpinning to the revenue flows an eventual interconnector owner would enjoy (such as a regulated cap and floor model), We accept that this would also involve CWP contributing in some way to the recovery of expense through some form of charge (accepting that it cannot be TNUoS as these are not applicable to interconnection[6]). However, we would also desire that a non-GB offshore strike price under the CfD then reflects the payment of contributions/interconnector charges in the way in which it is set. This approach would be consistent with (although necessarily not identical to) the treatment of GB offshore projects, able to use the OFTO scheme, but without necessitating a replication of the OFTO scheme for non-GB generation. In our view, it is right that we have a legitimate expectation of equitable treatment, hence if the GB consumer stands behind the OFTO licences (which they do) and this lowers costs and risks, then we should expect some sort of similar benefit in the way the regulatory framework is designed for non-GB offshore generation.

Until there is a decision on whether there will be regulatory underpinning or the nature of cost recovery there is no way to properly value the interconnector asset, or describe the business case and investment return to any prospective acquirer and long term operator. Equally, there is no way for CWP to financially assess whether the CfD strike price will allow CWP to recover any form of operating interconnector charge it might face under such arrangements. Thus, even if a technical solution could be developed for the purposes of procurement, the absence of this confidence leaves CWP in a challenging position when deciding whether to press ahead with making investments in the transmission assets in the first place.

This is why we recommend OFGEM making an unambiguous ‘Statement of Principles’ which includes a commitment to develop revenue models for ultimate use as interconnectors which include a degree of regulator/consumer cost underpinning. As OFGEM rightly point out, in the absence of such revenue models it is incredibly difficult to envisage a viable opportunity for an interconnector operator. Unless CWP has this certainty it cannot be certain that it will be functioning on a level playing field with GB offshore projects, particularly if it might be asked to compete for a CfD and LCF allocation in the future (which is an increasing possibility as a result of recent DECC announcements surrounding FID Enabling for Renewables and the Delivery Plan).

[6] in 2010 the requirement for interconnectors to pay TNUoS was removed

Question 3: *Are there other factors that Ofgem should be aware of relating to the timing and development of non-GB connections?*

OFGEM should take into account:

- The drive towards completion of the EU Single Market in electricity and the contribution that projects such as CWP can make to facilitating and accelerating that objective

- The commitment by both the UK and Ireland to explore and facilitate the trading of renewable energy between these two EU partner states

- The need for regulatory frameworks to provide solutions in timescales consistent with both developer and consumer needs, which are inter-related. The primary goal set by government, on behalf of consumers, is meeting the 2020 renewable energy objectives. Developers providing the capacity to deliver this energy have hard milestones and timetables under which significant investment commitments need to be made. If the regulatory *process* or *final framework* is inconsistent with these, then investment decisions will either be delayed or cancelled.

- increasing importance of EU and regional network planning, primarily via the TSO Ten Year Network Development Plans (TYNDP), but increasingly needing to incorporate significant infrastructure projects which are *developer led*, not TSO led.

- The need to examine whether existing processes properly support the facilitation of Projects of Common Interest and where necessary reform, adapt or expand the necessary processes.

- The need to ensure adequate security of supply in a manner consistent with the objectives for decarbonisation of the energy mix.

CHAPTER 2

Question 4: *Do you agree these are appropriate principles to take into account in relation to non-GB connections?*

Protecting consumers from exposure to undue costs or risks

"The regulatory framework should seek to allocate costs and risks to industry parties in a way that mitigates them most effectively and drives efficient decisions.
GB consumers should only face costs or risks where the potential benefit to them is clear."

We agree with the above principle. However, it should be noted that the determination of potential benefit may be the result of government policy, rather than a purely Ofgem internal assessment.

"There are also mechanisms whereby Ofgem applies specific scrutiny to investments where significant costs and/or stranding risks will be borne by GB consumers. Onshore, this is achieved through scrutiny of the transmission owners' (TOs) business plans as part of price control reviews and the Strategic Wider Works process. Offshore, we are introducing a gateway process whereby Ofgem will provide its view on the case for undertaking additional investment in offshore transmission assets where this would provide wider network benefit."

We have concerns regarding the application of any offshore "gateway process" designed for a different situation, to the connection of non-GB generation. The two situations are not comparable. The IGA will and should fulfil this action in respect of any Ireland-GB arrangements.

"If GB consumers provide any underwriting of non-GB connections, we would expect mechanisms to be put in place to ensure that appropriate costs, benefits and risks are allocated to the relevant non-GB generators."

We agree with the principle. It will be critical to ensure that all stakeholders agree on what is meant by "appropriate".

Promoting efficient capital and operational network costs

"For onshore transmission owners, we set allowed costs in the RIIO price control following scrutiny of TO business plans. We will also undertake a cost assessment to inform the setting of a regulated floor under the Cap and Floor regime for the NEMO interconnector."

Developers will require certainty regarding the methodology used in any cost assessment process that may be used and confidence that full allowed costs will actually be recovered. The uncertainties in the current OFTO regime regarding cost recovery should not be replicated in any Ireland-GB arrangements.

Promoting efficient and coordinated development of the network

"For non-GB connections, the physical location of the transmission assets and their cross-border nature mean that in principle they could provide an efficient way to support market integration as well as connecting non-GB generation. For the onshore and offshore networks, the National Electricity Transmission System Operator (NETSO) has a key role to ensure that connections are made in a timely manner whilst also taking into account wider system needs and the technical rules underpinning the planning of transmission infrastructure."

We agree that the NETSO has an important role and that market integration is also relevant. However, given the challenging timescales to deliver projects by 2020, the priority must be the connection of capacity. Strategic coordination is a matter to be fully explored in subsequent initiatives, including ITPR. We support the use of TSO expertise in providing coordination information to developers, but this should not be a mandatory role.

Supporting investment in low carbon electricity generation

We support Ofgem's statement that "*it is important that the regulatory framework ensures that new generation, including low carbon sources can be connected to the network in a timely manner and that network regulation supports generators' investment decisions appropriately.*"

Question 5: *Are there other principles that we should also we consider?*

Key further considerations for Ofgem include:

- Ensuring that the development of regulatory frameworks minimises regulatory risk for industry stakeholders and that legitimate expectations are not compromised by new policy developments. In turn, through minimisation of risk this is likely to lead to lower procurement and financing costs for CWP (and other projects) and hence creates potential for lower costs to the consumer than would otherwise be the case;
- Assisting in the completion of the Single Market (on a number of fronts) in order to bring increased benefits to consumers; and
- Ensuring that transmission regulation supports the development of networks to enable the above.

CHAPTER 3

Question 6: *We invite views on our interpretation of the different asset definitions/boundaries and interpretation of the legislation provided in this chapter. What implications does this have for the regulatory options presented in the next chapter?*

The interpretation appears logical. As stated, in our view, the interconnection framework in the broadest sense should provide the means to deliver the required outcome.

Question 7: *We are interested in views from stakeholders on what impact alternative interpretations would have on potential projects? Please provide detail where possible.*

We have not conducted our own legal due diligence on this subject so cannot comment on whether the interpretation set out in the consultation is correct. We agree that this is likely to be a matter of subjective legal interpretation rather than of objective fact. We believe it would be favourable if there was a legal interpretation of non-GB generation connecting to the GB electricity transmission system as falling within the definition of interconnection in the EU Electricity Regulation as this gives a clear route to CWP. It, builds on existing instruments like the GB interconnector licence, and allows us to work with OFGEM in seeking the appropriate exemptions. In absence of this it is not clear what route might be open to CWP as the principle asset configurations and regulatory options for cost recovery set out in the consultation are largely predicated on an interconnector licenced solution. Therefore, in our view, any alternative interpretations would be likely to:

- Require a sufficiently more work in determination, definition, coordination and application;

- Not meet the timescales for CWP's delivery by 2020;
- Expose developers to considerable uncertainty and unnecessary risk;
- Provide no additional benefits for stakeholders over and above working within the broad interconnector regime.

Question 8: *We seek input from stakeholders on how generation licensing for non-GB generation could ensure appropriate safeguards for the export of renewables to the GB transmission system?*

We agree that directly connected generation located outside of GB will need to reflect certain GB standards and requirements, to ensure the safe operation of the transmission system. One route to ensure this is to work with the relevant National Regulatory Authority in the partner state in order to ensure that appropriate conditions (where necessary) are present in the generation licence. Such standards should, where possible, be equivalent to those placed on GB generators connected to the same system. They will also reflect requirements for safe operation in the non-GB state. Given the integrated nature of generation and transmission in such projects, and the capabilities of HVDC technology, it will be important to ensure that the interconnector license conditions dealing with system standards and requirements dovetail appropriately with the requirements placed in the relevant generation licences.

CHAPTER 4

Question 9: *Are non-GB connections deliverable by 2020 via direct and exclusive connections?*

Yes. The engineering solutions for point-to-point, direct and exclusive connections are proven and available. Indeed, the evidence from Round 1 and Round 2 transmission connections in the GB offshore market demonstrates the technical viability of direct and exclusive connections, with 3.8GW either in development or completed direct and exclusive connections covered under Round 1 and 2 OFTO licensing arrangements.

CWP believes the construction of a direct and exclusive connection between the project and the GB network is achievable by 2020, assuming that there is sufficient confidence in the supporting regulatory frameworks to make the prepare for and then make investment in the proven technical solution as we progress through 2014**.**

Question 10: *What are the technology challenges of delivering direct and exclusive connections? What are the technology challenges of delivering multi-purpose assets?*

Further adaption of the direct and exclusive connection to include an onward connection to the non-GB network (in this case Ireland) is possible. We are aware that concerns have historically been raised about the lack of availability (and hence potential higher costs and longer lead times) for higher capacity cables and multi terminal hubs[7]. There is a risk of an inverse relationship between multiple functionality necessary to facilitate multiple use of a connection and the timing of delivery and multi-purpose assets are likely to require that additional consideration is given to appropriate network operation, protection and control.

Question 11: *What are the potential benefits and challenges of enabling flexibility for a non-GB connection to also be used for a) market-to-market trading; and b) GB network reinforcement? What are the implications for investment certainty?*

The benefits include:

- Efficient use of assets;
- Avoidance of duplication or reinforcement; and
- Enhanced operational flexibility/system security.
- Reduced costs to the consumer

The challenges primarily relate to the status of various stakeholders when an asset initially developed to provide one function has the opportunity to provide additional functions. It is unlikely that the additional functions will be obtainable without impacting the position of existing stakeholders in some manner. The processes for protecting the rights and legitimate commercial expectations of existing stakeholders when change occurs need to be defined at the outset. These will include the degree of "grandfathering" of initial rights and the (re) distribution of costs and benefits (including new costs and benefits) among all parties, when assets provide additional flexibility or services over and above their original remit.

The key factor in facilitating future additional flexibility is to design change processes which have as their core principle the protection of existing stakeholders/investors, but which do not seek to predefine every possible future scenario or option in detail. With this principle established and confidence generated in its practice, individual opportunities to exploit flexibility can be examined as they arise, building a body of best practice.

Critical to this process will be convincing the financing and investor stakeholders that flexibility will not prejudice their investment objectives or contravene their appetite for risk. The main financing considerations for investors when considering the viability of allowance for flexibility relate to:

- Delivery timing certainty & technical quality;
- Volume/route to market certainty;
- Revenue certainty;
- Cost recovery certainty; and

[7] http://www.ppaenergy.co.uk/web-resources/resources/d2738a47e2a.pdf

- Clear risk allocation.

Against that context, any arrangements for building in flexibility for market-to-market trading and/or GB network reinforcement are likely to need to accommodate the following principles in order to ensure investors are taken along on the journey:

a. Reserving capacity for generation - Regardless of alternative uses designated in the future for the connection there needs to be an obligatory reserving of capacity on the connection for the notified output of generating assets that were the genesis of its construction. This needs to be explicit in any framework in order to ensure the offshore plant is not 'stranded' in terms of its ability to export by any future use and hence is financeable or financeable at an economic cost in the first place. In simple terms, the generation assets have first rights of use up to a pre-notified capacity, with any surplus returned to an interconnector owner for subsequent auction if applicable;

b. Establishing a clear responsibility & revenue model for recovery of anticipatory investment and costs of developing connection assets– to accommodate multi-purpose assets it may be necessary and most efficient to build in the technical capability to accommodate future variations in use at the outset, and into the design of the scheme. This might include procuring and building cables to onshore substations in the non-GB network, providing additional capacity at landing points, or undertaking anticipatory pre-construction activities for more than one purpose or project. As previously mentioned, anticipatory investment and investment in the connection assets as a whole by CWP needs to be underpinned by regulatory certainty on the timing and amount of cost recovery, in an equitable way relative to GB offshore assets, in order to facilitate the most efficient financing route. Any outcome that sees CWP needing to repay the costs of building the interconnector through a long term financing arrangement is not an efficient outcome and may not be workable in light of the support offered under the CfD. Without clarity on the form regulatory support for the eventual owner/operator of the interconnector, the form of cost recovery and charges levied on the generating station, and how these are recoverable through the CfD then there are serious challenges for CWP in undertaking anticipatory investments or for investing in the core connection assets and hence completing the project. As set out earlier in our responses, the most viable alternative would be to incentivise (not force) developers to build connection assets through committing in principle to underwriting the investment via a regulatory mechanism for cost recovery (including financing costs), with the detail to emerge thereafter in the form of draft regulations. This could take the form of a regulated Cap and Floor model as described in the consultation proposal. Whilst we note the challenges of adopted a regulated fixed revenue model for this type of asset configuration, we believe there is a justifiable basis for some form of consumer underpinning of a floor revenue for the connection assets. If the benefits of multi-use connections are system wide then the cost and risk of delivery should be shared, and if the incentives are appropriate then there is no reason why developers cannot deliver sound developer led solutions that minimise delivery risks and costs. Furthermore, it is important that non-GB generation is not treated differently in principle to GB offshore generation who benefit from the presence of the OFTO regime as a means to make their developments (including developer led and financed approaches to transmission) economically viable.

c. Establishing a clear responsibility & recovery for incremental investment – as per b. above, similar principles will need to be developed in order to appropriately incentivise CWP to perform further works in the future to facilitate multi-use once construction has begun but ahead of any unbundling (i.e. during the construction phase). It is likely CWP would wish to control the performance of incremental works on the connection at this juncture to ensure management of interface risks. In this context, CWP may (depending on its financing strategy) be constrained in its ability to raise additional funding to facilitate the incremental investment even if this is underpinned in some way by regulation. This might be because of investors not wishing to extend their commitments to the project, but not wishing to bring in other new investors to meet the capital demand. Whilst CWP could attempt to negotiate flexibility to accommodate this into their original financing package there can be no guarantee of success. Therefore, there should be incentives through the design of the framework which allows for adjustments to the revenue floor under the cost recovery model to encourage CWP to make any incremental investment that postdates financial close for the project but predates the sale of the connection assets. Clear delineation of revenues owed under PPAs & CfD – It will be vital to investors that they have confidence that the volume used to calculate revenue flows to CWP can always be clearly delineated, measured and accounted for in order to facilitate PPA and CfD top up payments. As previously suggested, metering the generation of CWP at its connection point into an interconnector, once there is multiple use of the interconnector, and for the CfD to recognise the viability of this, would seem most sensible; and

d. Establishing clear risk interfaces – Regulatory frameworks will need to give consideration to the boundaries of risk and pass through of risk between different users of the connection once it is operational. From CWPs perspective, should third party users or operators of the connection prejudice CWP's ability to realise gross revenue from their generating assets that otherwise would have been achievable, or results in CWP incurring additional costs as a result of their act or omission, negligence or fault, then there should be arrangements for payment of proportionate compensation to CWP and the regulatory framework should incorporate these principles. This should cover situations of business as usual operation, as well as occasions when the connection is suspended to facilitate the incorporation of additional use.

CHAPTER 5

Question 12: *Is the interconnector licence with exemptions(s), as currently available, a feasible option for non-GB connections? If so, what are the key challenges of applying this route to non-GB connections? How could these challenges be addressed?*

Yes – it is an appropriate and applicable option, which should be pursued.

The key challenges are:

- Timing – the framework needs to be in place during 2014 in order to facilitate delivery of projects prior to 2020Coordination – there are a number of stakeholders involved in the process and it will be important to ensure that they have an effective and efficient means of contributing towards the desired objective – a suitable framework. Core stakeholders will be the GB and Irish regulators, UK and Irish governments, the EU regulatory authorities and importantly, the developers aiming to deliver projects under the regime.

- Consistency – the framework needs to be aligned with and supportive of, objectives of the IGA Appropriate allocation of risk and non-discrimination – we note elsewhere the guarantees given by the GB consumer to other offshore projects which operate under the OFTO regime. We seek a similar treatment via a revenue floor provision underpinned by consumers for the transmission assets which would provide the connection for non-GB generation projects.

Question 13: *Under this route would an exemption (under Article 17 of the Electricity Regulation) be required? If so, which provisions would you seek exemption from? How would your project be affected if exemptions could not be applied for?*

This approach is the one taken for previous interconnector investment in GB. The developer will need to ensure that it has access to the revenue that was expected at the time of the investment decision. Exemptions from certain provisions under EU legislation are likely to be required. For a basic asset configuration connection of non GB generation these will include Third Party Access and Use of Revenues. Unbundling provisions may or may not be required depending on the project proposal. Protection for developers would be via the provisions of the GB Electricity interconnector licence.

Ofgem recognise that it has proven increasingly difficult to realise interconnector investment under the merchant exempt framework and that exemption applications for interconnectors used to connect generation directly have not been pursued before. The risks for a pure merchant interconnector centre on revenue certainty and volatility. Although revenue risks remain for an interconnector connecting non GB generation, these risks are of a different magnitude and the ability to manage/hedge them will depend primarily on the quality of the generation project providing the interconnector revenue, rather than the uncertainties associated with long term energy market arbitrage.

We note that this option is best suited to basic asset configurations and may be challenging to expand its use to multi-purpose or complex asset configurations (although not impossible). It has the merit of being deliverable in a timeframe consistent with GB 2020 ambitions, and could then be utilised as a stepping stone to further development of non-GB offshore connections in time

Question 14: *Given that an application of the regulated Cap and Floor or fixed revenue model would take time to implement for non-GB connections, should these still be explored further?*

It is doubtful whether a fixed revenue model would be deemed appropriate by OFGEM for the purposes of the proposed asset configuration we have set out in this response. However, there are benefits in pursuing the regulated cap & floor option in a statement of principles and thereafter reflected in the substance of draft regulations. We accept that timing of implementation will be of concern but in our view without this approach being progressed expediently, it will be challenging for CWP to carry the investment risk in transmission assets (see our responses to the questions in Chapters 2 & 4) and such an approach will allow the best chance of utilising the cable as viable interconnectors for the realisation of the benefits of greater market-to-market connectivity in the future. .

These options would also allow the proper identification and inclusion of wider network needs in the overall process, potentially allowing the GB NETSO or TOs to contribute views on the interconnector asset design.

Question 15*: If so, what are the main challenges and benefits of applying a regulated Cap and Floor or fixed revenue model to non-GB connections? How could these be addressed?*

We agree with Ofgem's assessment of the challenges and benefits. With regard to the application of the Cap and Floor regime, we would suggest that when a direct and exclusive connection evolves to include additional either more conventional interconnection opportunities or system reinforcement, that would be the time to consider moving from a "simple" approach to a Cap and Floor model. Consideration would indeed be required as to how additional uses could be combined with the adjustments that would be needed to a plain Cap and Floor, given the existence of a (prior) directly connected generator, or a "hybrid" approach that combined a Cap and Floor for the market-to-market element with the existing direct-connect element.

CHAPTER 6

Question 16: *What is the appropriate mechanism for ensuring access to capacity for non-GB generation?*

Firm access to the GB system is a fundamental part of the business case for a non-GB generator and the interconnector connecting it to the GB network. It is likely that capacity allocation will be agreed over the expected project lifetime of the generation capacity (15-25 years). Where there are no other potential users of this capacity, we do not foresee significant issues arising. Availability incentives and compensation arrangements will be agreed between the generator and interconnector asset owner. We would expect Market Compensation arrangements in GB to fully apply to the non GB generation.

Where there are additional users of the connection assets, then we would expect existing access rights of the initial user to be preserved, under bilateral arrangements. Where capacity was not being used by the initial user, or there were opportunities to sell back capacity to third parties, we would expect these to be in line with principles established for other interconnection projects (which largely use the principle of auctions).

Question17: *What are the implications of following the current connections process for non-GB connections? Should non-GB generators be treated differently to GB based generation? Should non-GB generators be treated differently to other interconnector users? If so, please provide your reasoning.*

Where the connection is purely to provide a basic asset configuration, to connect non GB generation, then the current connections process should be used. All generators should be treated equally.

Question 18: *How would the role of the interconnector operator need to adapt if a direct-connect asset was used for additional purposes – such as a) market-to-market interconnection; or b) GB network reinforcement? Should the GB or non-GB NETSO have a role in operating these assets? If yes, what role?*

The optimal role of the NETSO will ultimately depend on the way that the assets are configured and used. Clearly, where the assets play any role in GB network reinforcement, the GB NETSO will require confidence that the assets will be operated under its direction, in order to ensure that its duties regarding safety, security and stability of the network can be effectively discharged.

Question 19: *Can the existing charging/cost allocation approaches used onshore or for interconnection be applied to non-GB connections? If not why not and what alternatives are available?*

Yes. Non-GB connections will comprise (at a minimum) a generation and transmission element. We would expect charges at the GB point of connection to be determined on the same basis as other assets operating under the interconnector regime. We note that with the removal of the requirement to pay TNUoS on interconnectors, concern has been expressed that appropriate locational signals may be missing, when considering any choice of connection point. However, we believe that these concerns can be met by dealing with optimisation via the existing processes for making a connection offer carried out by the System Operator.

We are not advocating a fully regulated approach to funding the transmission assets and as such the charges levied on the generation project for use of the transmission assets are primarily a bilateral commercial concern for the two parties involved. However, as discussed elsewhere, we are seeking the equivalent risk allocation that other offshore transmission assets benefit from under the effective OFTO revenue guarantee provided by the GB consumer. For the non-GB transmission assets, this would be based on an assessment by Ofgem (as per the OFTO process) of the efficient level of costs incurred in delivering the project, given the information available to the developer at the outset. Following this assessment, a floor or guarantee would be put in place to support the required OFTO revenue. Under normal circumstances, this revenue would be provided by the generation project. However, in exceptional circumstances it would afford the same protection to the transmission asset owner as that given under the OFTO regime. The benefits of providing this guarantee would be a substantially de-risked project profile which brought risks within acceptable limits for the developer (and hence lowered risk adjusted costs) and provided a more cost effective solution for the GB consumer.

Question 20: *How can capacity allocation for direct and exclusive connections ensure consistency with European legislation and European Network Codes? How could this be achieved with the introduction of market-to-market connections?*

It is unlikely that the Codes have been developed to address this situation. So, rather than seeking to squeeze the opportunity into the Codes, we should identify the principles that the codes are built on, and propose capacity mechanisms which are consistent with them. The Codes can then be modified to incorporate the novel application, noting that the timetable for proposal of modifications should synchronise with the publication of draft regulations before the end of 2014, so that developers and investors can assess both as a package

Question 21: *Are there other challenges we should be considering when looking at non-GB connections?*
There are no other material issues that we have not already covered in our responses to the other questions.