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FINAL DRAFT – 09/03/2011

DECC Electricity Market Reform Consultation Response

1. Do you agree with the Government's assessment of the ability of the current market to support the investment in low-carbon generation needed to meet environmental targets?

The aim of the EMR is to foster investment in "low-carbon generation". With this new concept the Government is bundling for the first time renewables with other technologies such as nuclear and CCS. In our view, the current market support for renewables has worked well, playing an important role in the development of UK's renewable energy sector so, although we recognise Government's imperative to foster nuclear energy and CCS we question the real need to change a support system with such track record for renewables. Thus, our main concern now is that within the proposed system, attractiveness of renewable business is not affected.

2. Do you agree with the Government's assessment of the future risks to the UK's security of electricity supplies?

3. Do you agree with the Government's assessment of the pros and cons of each of the models of feed-in tariff (FIT)?

No. EDPR is **extremely sceptical of the CfD FIT**, when applied to non-dispatchable energy sources, such as wind. Thus, we do not see in it any potential to bring forward investment in renewables. For this analysis we think is important to make the **distinction between dispatchable and non-dispatchable energy sources.**

- Although we agree that CfD FIT provides an important incentive aspect for dispatchable energy sources, there is an aspect which must be looked out for which is ensuring the ability of the agents to manage the risk of not being able to replicate the price index on which the remuneration is benchmarked
- On the other hand, we believe the CfD FIT, when applied to non-dispatchable energy sources, opens a very important risk position in the remuneration for the agents. This is so because the index is very likely not replicate actual market revenues, making actual revenue uncertain. Since wind generation cannot be controlled it may well generate at low price hours, contributing to depressing prices even further, and with a very limited advantage on the pursuit of the Government's objectives (in this case, the maximization of availability at the times when the system most needs it)
- Also, considering the revenue uncertainty that this system creates, given our expertise we are very doubtful as to whether this type of remuneration is bankable at all, considering that virtually no part of the revenue is known with certainty beforehand
- These downsides are not compensated by any significant upside; the only benefit would be the incentive to perform maintenance at economic moments, which is a minor advantage compared to decrease in bankability and increase in project risks versus fixed FIT. We consider that other schemes could also pursue this objective without creating this risk

It may be argued that the CfD system could be "fixed" with the choice of an adequate index (other than the baseload), but any price index will be just an index, introducing uncertainty: in the current system with ROCs basis risk is present only in the market tranche of the remuneration, however with a CfD scheme basis risk will be present not only in the market price but also in the premium tranche of the remuneration. We cannot think of any scheme that would remove price uncertainty (which is aggravated by the correlation of the generation profiles of wind generators, for example), while still addressing the incentive objectives of the Government.

CfD FIT for renewables adds substantial risk and uncertainty, making financing more expensive while failing to provide any extra incentive towards efficiency as IPPs cannot control wind resource but do pressure price downwards.

Regarding the **premium FIT**, we agree that with the increased penetration of non-dispatchable generation with zero marginal cost, the price signal of the market will be less relevant and more risky, thus reducing the value of the variable remuneration component. However, we consider that

introducing a cap and a floor on the hourly remuneration a station receives (which could coexist or not with a premium) could be a way to deal with the price uncertainty and the risks of over or under-remunerating a generating station. The *de-facto* premium would then be variable, since it would be lower (or zero) in high price hours and higher in low price hours. This structure has the advantage of maintaining a price signal for the generator to optimize availability (since the remuneration is higher in high price hours), without the added risks of the CfD FIT. A correct calibration of the cap and floor values would partially insulate the low carbon generator from the long term average electricity price risks (including CO_2), and thus reduce the government's fears of overcompensation. In any case and when comparing to the CfD FIT, the premium FIT has the advantage that a part of the remuneration is known with certainty and this certainty may enhance bankability.

We consider the **fixed FIT to be the preferred option**. On the consumer side, the fact that it is fixed provides a hedge on fuel price variations (since when energy becomes more expensive in general, the cost of this parcel does not change, being that the "overcost" of the subsidized generation only increases when the system costs decrease, meaning there is more space to absorb it). For developers, it is not only more easily predicted, but it is also more constant, and safer (the developer knows with the most certainty what is the net price it will receive).

Regarding other types of promotion systems mentioned in the consultation document:

- We consider that the **Low Carbon Obligation** is, in our view, very similar to the premium FIT, with the added disadvantage of carrying a greater uncertainty on the ROC revenue. However, the implementation of this type of system has the advantage of avoiding or minimizing a regulatory change, with all the disadvantages that a regulatory change has on the investment signals and the confidence of the investors. It has the advantage of providing easier access to offtake agreements (on the part of the developers), since they can bundle their energy with the obligation certificates to make the package more attractive
- We agree that the RAB approach will create turbulence in the transition period, and will unnecessarily eliminate incentives for efficiency and optimization and thus deem this approach as undesirable.

4. Do you agree with the Government's preferred policy of introducing a contract for difference based feed-in tariff (FIT with CfD)?

While in concept the CfD-type FIT is virtually the same as the fixed FIT with the added advantage of providing a price signal, we find that in practice that is not the case because of the inability to find a suitable price reference. Considering the expected increase in wind penetration and other non-dispatchable energy sources the generation of these energy sources will be concentrated on specific time periods, with low prices, whereas higher prices will exist on other time periods, making the average electricity price irrelevant for these energy sources. Wind energy may present a negative correlation with a fundamental market-based reference; as non-dispatchable will get increasingly less than average reference price while retaining volume risk as wind volume maximums are unlikely to coincide with anti-cyclonic winter price peaks. (see figure 1 for a graphic monthly representation[1])

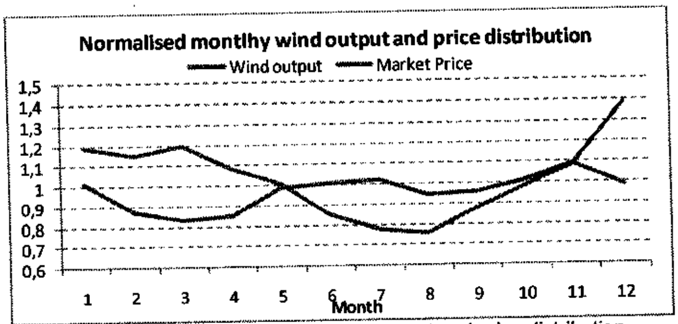

Figure 1: Normalised monthly wind output and price distribution

[1] The data for the wind production come from a selection of the data base ds461.0 (http://dss.ucar.edu/datasets/ds461.0/) from NCAR (National Center for Atmospheric Research) and prices are annual average APXMIDP

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Moreover, we consider that price signals are mostly irrelevant for non-dispatchable sources because they cannot optimize their generation, only the programmed downtimes. A premium feed-in with a floor and cap (such as the Spanish), or a "fixed" feed-in with a narrow variation band around a central value (the variation of which would be pegged to market price variations) would provide a price incentive to generators to optimize their programmed downtimes, while not exposing them to revenue uncertainty from not being able to manage their generation and being exposed to correlation with other generators.

We disagree with DECC's view that a suitable index could be found that solves the price uncertainty for the generator while still maintaining the adequate level of incentive for optimization of availability. Any price index will be just an index, introducing revenue uncertainty. We believe that an index with all above characteristics does not exist, and thus disagree to this option being implemented.

Also, given our expertise we have serious doubts as to whether a CfD-type of tariff provides any certainty to the investor and whether it is bankable at all. In addition, as highlighted by Scottish Renewables[2] the Dutch system mentioned in the consultation as an example of CfD FIT has seen criticism in recent years, along with undergoing review. This criticism relates to whether such a mechanism is able to sufficiently accelerate investment in renewables over the next decade to meet the Netherland's 2020 targets, and in particular the deployment of offshore wind. As such, there is currently a consultation on introducing a more specific supplier obligation very similar to the Renewables Obligation. An obligation and tradable green certificate scheme is seen as a stable market based solution for securing these targets at lowest cost.

Also **project's hurdle rates would be higher** due to higher cost of debt, lower possible leverage and higher cost of equity as explained in question 7.

Having said all of that, and if finally the decision to set a CfD-type tariff is taken, we urge DECC to consider some implementation issues. Despite the fact that EMR is addressed to a wide range of energy sources, all included within the concept of "low-carbon energy sources", the **substantial differences those energy sources have will require a different remuneration approach**. Thus, DECC may consider setting up different CfDs/prices per technology. Also, with the implementation of the CfD, DECC may consider **setting an absolute floor price -including balancing- for all the production of the plant.**

5. What do you see as the advantages and disadvantages of transferring different risks from the generator or the supplier to the Government? In particular, what are the implications of removing the (long-term) electricity price risk from generators under the CfD model?

In our view, the Government's objective should be to achieve the targets at a minimum cost. Cost is minimized when risk is minimized, and allocated to the players who are the natural owners of the risk. When electricity price risk is allocated to a wind generator, it is exposing the wind generator to oil, gas and other fuel price risks, that are not natural the generator and that the generator cannot manage. This compares to a conventional generator who is exposed to those markets on the fuel cost side and the electricity market provides a way to pass on and manage those risks. The electricity market exposure for a wind developer results in an increase in risk and higher overall costs given by an inefficient risk allocation.

This electricity **price exposure remains partially under CfD model and disappears under the fixed-price tariff.**

It seems to stem from the consultation document that the Government sees the off-take risk being on the developer side as an advantage. We fail to understand the logic of that since the need for investment in low carbon generation stems from the path set by the UK Government to reach its targets, rather than market signals on lack of low carbon generation. Since the investment signals come from the Government's targets themselves and the path to reaching them, we see no specific advantage in having the developers keeping the off-take risk, but rather a disadvantage to the whole system, since it increases the uncertainty.

[2] Scottish Renewables Association - representative body of the renewable industry in Scotland

6. What are the efficient operational decisions that the price signal incentivises? How important are these for the market to function properly? How would they be affected by the proposed policy?

We believe that an important distinction needs to be made (which will likely be a differentiating factor on deciding which is the best solution for each type of generation) between **dispatchable and non-dispatchable energy sources.**

For **dispatchable energy sources** (such as biomass, for example), price signals provide incentives to generate electricity in the hours of higher price (where it is needed the most), as well as to manage downtimes on low price hours. On the other hand, for **non-dispatchable energy sources,** price signals only incentivize the optimization of programmed downtimes (such as preventive maintenance), since the operator cannot decide when to generate electricity. We consider that for the specific case of wind energy the price signal provides only a marginal incentive, and thus the advantage of the price signal needs to be weighted against the disadvantages its implementation brings. Specifically for the case of the CfD FIT, we consider that the costs that this option brings to non-dispatchable generators outweight the advantages by a wide margin. An IPP cannot control wind so the incentive to trade efficiently pursued a CfD FIT is lost.

This is even truer for offshore operations, where maintenance will be done when physical assets (such as vessels, crews, helicopters, etc) are available and will not be linked to specific incentives for a specific time of the day or year.

7. Do you agree with the Government's assessment of the impact of the different models of FITs on the cost of capital for low-carbon generators?

No. We consider that a **CfD-type feed-in carries greater uncertainty to the developer**, and thus implies a higher cost than the fixed Feed-in.

Analytically, the relationship between the hurdle rates used as base for the analysis do not match our experience. **Hurdle rates used in CfD FIT should be higher than the ones with fixed FIT:**

- Cost of debt will be higher corresponding to a project with higher revenue certainty
- Leverage will be lower to protect bank interest and force equity holders to provide guarantees
- Equity holders / investors will assign a higher cost of equity to cover for the guarantees and cash flow uncertainty

8. What impact do you think the different models of FITs will have on the availability of finance for low-carbon electricity generation investments from both new investors and existing the investor base?

We consider that the fixed FIT is the safest option, and thus the one that might attract a wider pool of capital, since less expertise is demanded from the capital providers (the system is just easier to understand and to predict).

For the case of the Premium FIT, even though the revenue stream is less certain (although the carbon price support plays a part in making electricity prices more predictable), a part of the revenue is known with certainty, and there is also already some experience with financing projects like those in Spain.

Finally, when it comes to the CfD FIT, we consider that this type of remuneration is not easily predictable (at least for non-dispatchable generators, as explained previously in advantages and disadvantages of each type of tariff), nor is there a revenue stream that is certain (the only revenue the generator is sure to receive is the difference between the agreed price and the index, where it can hardly be considered that there is a number that a bank will consider as certain). Moreover, the consultation also states how low-carbon generators may face negative cash flows in the case of a price index above the indicated reference price; this opens a new market price risk adding more uncertainty from a funding perspective. This situation for example does not happen in the Netherlands (example provided by DECC in the consultation document), where while it is true that they have a model similar to the CfD FIT if the electricity price goes above the strike price the generator keeps all the upside.

For these reasons, we think that this option carries the greatest uncertainty, and we have doubts on whether it is possible to finance the assets at all.

9. What impact do you think the different models of FITs will have on different types of generators (e.g. vertically integrated utilities, existing independent gas, wind or biomass generators and new entrant generators)? How would the different models impact on contract negotiations/relationships with electricity suppliers?

We consider that the options with merchant exposure **impact independent generators** in getting access to the market for electricity, (it remains to be seen what is the market's appetite for a large number of PPAs for electricity only) in a way that probably doesn't affect integrated utilities, who are at an advantaged position, not only because they have internal demand for their generation, but also because they can take advantage of a portfolio effect in the balancing their generation

Using Scottish Renewables reasoning, if suppliers are no longer obligated to purchase renewable power, generators could then be exposed to a significant degree of off-take risk. In these circumstances, higher discounts could be applied to the terms of a Power Purchase Agreement. Consequently, the revenues a generator would expect to receive under this contract would decrease. When securing financing, banks prefer the certainty of long term power contracts. If these are more difficult to secure because an obligation to provide them has been removed, the transfer of risk to the financial institution will be complemented with an increased cost of capital for the generator. This potential squeeze on revenues and costs has caused a great deal of concern for independent power producers. It has the potential to offset any intended gains from a reduction in hurdle rates, and instead increase the overall cost to the consumer.

10. How important do you think greater liquidity in the wholesale market is to the effective operation of the FIT with CfD model? What reference price or index should be used?

Market liquidity is clearly related with market competition. Ofgem published reports on this matter show how there are clear iliquididity signs not only in the index prices representation but also in the market players and products available. This reinforces the **need to align the market reform with the work on liquidity so as to minimise embedded risks such as offtaker-risk and price distortion** (which becomes even more significant in the case of an illiquid market).

However and even in the conditions of improved liquidity, we are extremely concerned about the risks of a feed-in with a CfD type model, as we are **unable to find a reference price or index that will be representative for wind generators.** While in theory an index could be created on the average realised wind-energy price, we cannot see what is the advantage of such a price signal on wind generators to the electricity market.

11. Should the FIT be paid on availability or output?

Considering all the necessary investments not only in generation assets, but also in grid, demand response, etc, and the role that policy plays in managing the generation mix, transmission investments, etc, we consider that the developers are not the best entities to take or manage curtailment risks, but rather those who can influence the change in the UK's energy footprint (this is the case especially for non-dispatchable generators, because of correlation). For this reason, we consider that the FIT should be paid on availability to generate, rather than on generation after curtailment.

This is what happens today, where curtailment is settled on the balancing market, and not decided administratively. However, if the system changes, and generators are no longer exposed to the balancing market, or there is an administrative decision to cut-off plants at certain times, then some substitute mechanism would have to be implemented. The way to implement this could be to have the FIT paid on intended generation (i.e., on actual generation plus curtailed generation). A compromise solution would be to establish a lower payment for curtailed generation (bigger than zero, but lower than the FIT) or a capacity payment for available but curtailed generation, but the Government should take into consideration that this opens a risk position for the generator.

On the other hand, for dispatchable generators load factor risk could be more adequately managed through capacity payments, which is why we consider payments on output more adequate for dispatchable generators.

12. Do you agree with the Government's assessment of the impact of an emission performance standard on the decarbonisation of the electricity sector and on security of supply risk?

We agree with the Government in that the EPS will help to discourage investments in polluting generation sources thus fostering low-carbon generation.

13. Which option do you consider most appropriate for the level of the EPS? What considerations should the Government take into account in designing derogations for projects forming part of the UK or EU demonstration programme?

14. Do you agree that the EPS should be aimed at new plant, and 'grandfathered' at the point of consent? How should the Government determine the economic life of a power station for the purposes of grandfathering?

15. Do you agree that the EPS should be extended to cover existing plant in the event they undergo significant life extensions or upgrades? How could the Government implement such an approach in practice?

16. Do you agree with the proposed review of the EPS, incorporated into the progress reports required under the Energy Act 2010?

17. How should biomass be treated for the purposes of meeting the EPS? What additional considerations should the Government take into account?

18. Do you agree the principle of exceptions to the EPS in the event of long-term or short-term energy shortfalls?

Yes, but only for very specific reasons and for short-term shortfalls. The creation of an exception should be decided by a third party, such as Ofgem, for example.

19. Do you agree with our assessment of the pros and cons of introducing a capacity mechanism?

We consider that capacity payments are a necessary means to support the existence of enough back-up capacity, in a world with increasing non-dispatchable generation.

20. Do you agree with the Government's preferred policy of introducing a capacity mechanism in addition to the improvements to the current market?

In order to prevent market price from distortions, which at end may affect also the selected market index, the capacity mechanism should be targeted only to peaking plants. With that configuration the Government will support (and remunerate) the existence of back-up capacity in the system while leaving aside power plants that usually set market price, thus without creating price distortions.

21. What do you think the impacts of introducing a targeted capacity mechanism will be on prices in the wholesale electricity market?

With a targeted capacity mechanism prices in the wholesale electricity market may go down. To avoid such effect the capacity mechanism should be set in the way explained in question 20.

22. Do you agree with Government's preference for the design of a capacity mechanism:

- **A central body holding the responsibility;**
- **Volume based, not price based; and**
- **A targeted mechanism, rather than market-wide**

23. What do you think the impact of introducing a capacity mechanism would be on incentives to invest in demand-side response, storage, interconnection and energy efficiency? Will the preferred package of options allow these technologies to play more of a role?

24. Which of the two models of targeted capacity mechanism would you prefer to see implemented:

- **Last-resort dispatch; or**
- **Economic dispatch**

25. Do you think there should be a locational element to capacity pricing?

26. Do you agree with the Government's preferred package of options (carbon price support, feed-in tariff (CfD or premium), emission performance standard, peak capacity tender)? Why?

We don't agree with the Government's preferred package of options. As we mentioned before, we considered the **fixed FIT to be the preferred option** from the feed-in tariff proposals stated in the consultation, so from our point of view the preferred package should include it.

This is the only option that removes the off-take risk, aspect of significant relevance since the options with merchant exposure will have a great impact on independent producers. As mentioned in previous answers, it is uncertain the market appetite for PPA's for electricity only (not bundled to other products as ROCs as in today's current regime), giving independent producers a disadvantageous positions vis a vis vertically integrated utilities. On the other hand, one of the main concerns expressed by the DECC when assessing this option is that low-carbon generation would be insulated from price signals. However for non-dispatchable generators price signal are irrelevant since the operator cannot decide when to generate electricity. Moreover electricity price risk should be allocated to the naturals owners of the risk. The proposals undervalues the fact that minimizing the risk (price + offtaker), also minimizes the cost and this has a positive effect in the overall system. Finally, although the proposal also states that under this type of FIT generators won't be incentivized to balance their position, a fixed FIT can be compatible with incentives to producé accurate forecast.

Notwithstanding the above, between CfD FIT and premium FIT we clearly position ourselves in favour of the premium FIT. As it is presented, this option is similar to the existing RO regime with the advantage of removing the long term uncertainty of the ROC price. The structure undervalues the importance of minimizing the regulatory change when addressing the investors' confidence and a possible investment hiatus. Moreover, the proposal only considers a system with a fixed premium: A variable premium with a cap and a floor (as exist currently in Spain under RD 661) would correct negative effects both to the investor and the ratepayer while providing more certainty to the remuneration. A correct calibration of the cap and floor values would partially insulate the low carbon generator from the long term average electricity price risks (including CO_2), and thus reduce the government's fears of overcompensation

27. What are your views on the alternative package that Government has described?

EDPR's view on the alternative package is highlighted in question 26.

28. Will the proposed package of options have wider impacts on the electricity system that have not been identified in this document, for example on electricity networks?

29. How do you see the different elements of the preferred package interacting? Are these interactions different for other packages?

As mentioned by the Government, the targeted EPS has very limited interaction with the other three elements of the package. Capacity mechanism may affect FIT since it could affect wholesale market price which may be linked to the final remuneration of the power plant under a CfD or premium FIT system.

30. What do you think are the main implementation risks for the Government's preferred package? Are these risks different for the other packages being considered?

Regardless the package selected, the main risk derived for the implementation of the new mechanisms is an investment and development hiatus. The final reform needs to avoid as much as possible complexity (which may act as a barrier of entry), set up clear transitory rules between previous market support mechanisms and the new one and also be more clear with the specific details each of the measures will entail.

31. Do you have views on the role that auctions or tenders can play in setting the price for a feed-in tariff, compared to administratively determined support levels?

- **Can auctions or tenders deliver competitive market prices that appropriately reflect the risks and uncertainties of new or emerging technologies?**
- **Should auctions, tenders or the administrative approach to setting levels be technology neutral or technology specific?**
- **How should the different costs of each technology be reflected? Should there be a single contract for difference on the electricity price for all low-carbon and a series of technology different premiums on top?**
- **Are there other models government should consider?**
- **Should prices be set for individual projects or for technologies?**
- **Do you think there is sufficient competition amongst potential developers / sites to run effective auctions?**
- **Could an auction contribute to preventing the feed-in tariff policy from incentivising an unsustainable level of deployment of any one particular technology? Are there other ways to mitigate against this risk?**

We share Scottish Renewables' view on auctions: By their very nature, auctions inherently assume a surplus of potential capacity and seek to identify the most cost effective of that surplus. Currently, there is not enough capacity in existence, or firmly committed to in the near future to meet UK requirements. The renewables industry therefore requires a system that provides longer term incentives for the development of additional and more economic capacity, rather than a snapshot contest between current limited resources, which could lead to bottlenecks in both the supply chain and planning system. Auctions are unpredictable and provide no basis for longer term investment and cost reduction.

We are extremely fearful of a tender system as a means to license capacity. Regardless when the auction takes place, before or after development, we believe this system will not deliver the amount of low-carbon energy the UK needs. We foresee a significant reduction of players willing to take part in this new game:

- **Before development:** if the tender process takes place before development participants will be facing both financial and "pure development" risks.
    - As the development is still to take place, bidders have no information on project associated costs (just mere estimates). This uncertainty regarding costs may well make players, as they want to be hedged from cost uncertainty, to submit extremely high bids. On the other hand, influenced by auction's nature of least cost, players could tend to be over optimistic in estimating how much revenue support is required.

By failing in their estimates, winning bids may be far too low to realistically support the projects, thus there will be the risk of projects not being actually build.

- Winning projects will also have to face all the inherent development risks. Undergoing through a normal development process may end up with projects being successful and completely built as planned while other could be stopped or only built in partially.

- **After development:** the revenues (and thus profitability) of the project are totally unknown at the time where a decision to develop a project has to be taken, which will reduce the developer's willingness to devote resources to that project. Together with Scottish Renewables we believe that only very few players would be willing to commit the substantial development capital and large amount of work required to submit bids without any guarantee of contract. Besides, If the tender is successful and, as desired, there is a lot of competition in the tender; the outcome will be a price which remunerates only the costs that have not yet been incurred. Since development costs are significant, and non-recoverable, the developers will not be keen on spending money developing an asset because they are afraid they may not recover those costs, even if they win the tender. As there are many significant hurdles to overcome in the development of a plant in the UK, we consider this to be a major pitfall

Moreover, Scottish Renewables showed us the UK's renewables industry has had relevant experience with an auction based system through the Non Fossil Fuel Obligation, which is generally considered to be negative. A return to such a system would not serve to maintain current investment levels, nor accelerate them. In fact, it could result in quite the opposite.

Tender systems are especially disadvantageous for experimental technologies, since there simply much more uncertainty. In Scottish Renewables we have seen there is a significant lack of precedent for assessing how successful an auction based system would be for emerging industries. In particular, how are precommercial market participants able to realistically determine how much support they require for a prolonged period into the future? This lack of precedent only acts to increase the risk these industries are exposed to, and is not a sustainable means of determining support levels for them.

We believe that technological neutrality can never be really achieved, since (when aiming for technological neutrality) the differential on top of the basis price is set administratively, and will inevitably benefit some technologies to the detriment of the other. For this reason, and to achieve a balanced but cost-effective technological mix, the approach should be technology specific. In terms of the implementation we cannot see the difference between a CfD value for each technology, or a CfD value for all with a different premium on top of it; they seem the same to us.

We believe a periodic review, such as the one that exists today for the banding in the RO system is the best mechanism to adjust the remuneration parameters. Another option, which we favour less, could be to periodically adjust the remuneration value based on the fulfilment of targets, with a set formula (this is the case for the new solar PV tariff in Spain, where the tariff is adjusted quarterly depending on whether the capacity cap in the previous round was achieved or not).

As much as possible, **prices should be set for technologies**, rather than for specific projects, since that is a way to promote transparency. However, there might be a need to tailor the remuneration level to the project's specific conditions, this potentially being the case for offshore wind, for example. One potential way of accomplishing this would be to follow some of the features of the German model, whereby the tariff duration is extended (but could also be increased, instead of extended) for projects above a certain distance from shore, and above a certain water depth.

In the case of offshore wind (Round 3 mainly), it doesn't make sense to put projects in price competition, since they have economics that are very distinct from all other renewables projects in the UK, and indeed, each other. Also, we question how such a tender would be run:

- Would there be a tender for building a specific zone, which has already been attributed in exclusivity to a consortium?
- Would consortia tender their zones against each other, meaning there would be "n minus 1" zones being tendered?
- Would Round 3 offshore projects tender against other offshore wind projects, whose economics are not comparable (such as Round 2, Scottish territorial waters, etc)?

In our view, none of these options make sense, and thus **EDPR does not favor tenders for offshore wind projects.**

In specific, and when comparing to the examples presented, in the consultation document, we consider that they are not comparable and/or do not provide clear proof that they have worked. Being more specific:

- The amount of offshore wind capacity that Denmark or the Netherlands want to get built is nowhere near the aspiration of the UK (according to the respective NREAPs, Denmark has a target of reaching 1.3 GW of offshore wind in 2020, and the Netherlands has a target of 5.2 GW, while the UK has a target of 13 GW.
- The Danish system is not really a Contract for Difference as presented, but rather a fixed feed-in tariff, whereby the revenue comes from 2 different sources (the market pays the generator the wholesale price of that hour, and the regulator tops-up the revenue to reach the guaranteed value). There is a limitation on the number of hours that are eligible for a premium, though.
- In the Danish tender the site was selected and consented by the Government, the connection was built and paid for by the TSO, and the developer only had to build and operate. We find this to be very distinct to the case of the UK.

Having said all the above, we entirely oppose the use of auctions. Auctions in the renewable industry have a poor track record in other countries (Brazil); introduce uncertainty that might undermine investor and participant's confidence and neither do they support new entrants nor development of pre-commercial technologies.

32. What changes do you think would be necessary to the institutional arrangements in the electricity sector to support these market reforms?

33. Do you have view on how market distortion and any other unintended consequences of a FIT or a targeted capacity mechanism can be minimised?

Market distortion can be the result of creating market rules clearly favourable either to certain technologies or to certain market players. This is why we consider that one-size does not fit all low carbon technologies, that the differences between technologies (dispatchable vs. non dispatchable) should be addressed and that price risk should be attributed to their natural owners.

34. Do you agree with the Government's assessment of the risks of delays to planned investments while the preferred package is implemented?

We believe that uncertainty about the new system will only fully disappear once it has been fully operational for a while (having some "performance history"), which means that there is the risk of lags and delays. For this reason, we believe that the current and new system should coexist for some time, and the new system should be defined in detail as soon as possible.

35. Do you agree with the principles underpinning the transition of the Renewables Obligation into the new arrangements? Are there other strategies which you think could be used to avoid delays to planned investments?

Taking into account the timelines of the 2020 EU renewables target as well as, for example, the timings of the Round 3 offshore wind farms, we believe that the RO limit for accreditation should be extended *at least 2 or 3* years further (i.e. beyond 2017), so as not to jeopardize the fulfilment of these targets.

If the Government disagrees to this option, then an exception should be open for major assets that start being accredited close to (but before) 2017. We consider that the schedules of the Round 3 wind farms, for example, which are expected to start accreditation close to 2017, put them at a position where they are too late to take full benefit of the RO (full commissioning will be later than March 2017), but too early to factor in the details and any performance history of the new regime. This puts them in a position where the asset will probably be forced to enter the new system (so as to take full benefit of the support mechanism), but there will be insufficient information at the time where some of the decisions have to be made. For this reason, we consider that a limited number of phases should be allowed post-2017 (including full 20 years of support, past March 2037), for assets that have had partial accreditation before March 2017 (and fulfil certain criteria).

36. We propose that accreditation under the RO would remain open until 31 March 2017. The Government's ambition to introduce the new feed-in tariff for low carbon in 2013/14 (subject to Parliamentary time). Which of these options do you favour:

- **All new renewable electricity capacity accrediting before 1 April 2017 accredits under the RO;**
- **All new renewable electricity capacity accrediting after the introduction of the low-carbon support mechanism but before 1 April 2017 should have a choice between accrediting under the RO or the new mechanism.**

We favour the second option, because we see an advantage in having a period where the more risk adverse agents can still opt for the established system, while the new one isn't "proven" yet, but there is already an opportunity to gather experience with the new system, for the agents that want to do so.

37. Some technologies are not currently grandfathered under the RO. If the Government chooses not to grandfather some or all of these technologies, should we:

- **Carry out scheduled banding reviews (either separately or as part of the tariff setting for the new scheme)? How frequently should these be carried out?**
- **Carry out an "early review" if evidence is provided of significant change in costs or other criteria as in legislation?**
- **Should we move them out of the "vintaged" RO and into the new scheme, removing the potential need for scheduled banding reviews under the RO?**

38. Which option for calculating the Obligation post 2017 do you favour?

- **Continue using both target and headroom**
- **Use Calculation B (Headroom) only from 2017**
- **Fix the price of a ROC for existing and new generation**

We see no need for the use of fixed targets, with the increased costs they bring to the system from the high uncertainty that exists today on the amount of eligible generation under the Renewables Obligation as the system approaches its end, and no clear advantage, so we exclude the first option. When comparing the "calculation B" approach vs. a fixed price, we believe that a fixed price will probably reduce the administrative costs of managing the system, as well as reduce the price swings from unexpected changes (such as a large wind farm exiting the system, for example), so we prefer the latter.