renewableUK
The voice of wind & marine energy

RenewableUK previously: BWEA

RenewableUK response to the Electricity Market Reform Consultation

Executive Summary

RenewableUK supports the Government's long-term objective of decarbonising electricity generation in the UK. We also acknowledge that reform of current electricity market arrangements is required to accelerate investment in low-carbon generation. We have always been a strong supporter of the Renewables Obligation (RO). Our members believe the RO has delivered effectively and were disappointed to see that retention of the RO was not an option in the Department of Energy & Climate Change's (DECC) Electricity Market Reform (EMR) Consultation Document, but we are not proposing that the RO be reinstated. Given the Government's intention to move to a new system of support, we now hope to work constructively with the DECC to forge a workable system.

This submission puts forward our view on the options proposed in the Consultation Document, albeit that the Government did not present the detailed design of each option. The provision of detail will be essential if the renewable energy industry is to make an informed choice. Whatever mechanism the Government moves to put in place, it is vital the industry stays engaged in its refinement and on its implementation, in order to prevent unintended consequences occurring and to avert any hiatus in investment. The EMR White Paper needs to be clear on how the Government intends to protect existing investments and on how it will manage the transition with this objective in mind.

Our key points on the EMR are as follows:

- We are not opposed to a contract-for-difference (CfD) mechanism in principle; however, it is essential that the implementation of the CfD addresses basis risk and offtake risk and that the mechanism underwrites market liquidity.
- Of the options presented in the DECC Consultation, we believe a premium feed-in tariff (FIT) would provide the greatest certainty to renewable generators and investors; is closest in design to the RO; and will cause the least amount of disruption to current and planned investments. Offtake risk is also an issue with the Premium FIT.
- We support giving projects the choice between the RO and FIT for a transitional period, but we are concerned that the long lead time for large-scale projects means that an accreditation deadline of 2017 does not leave room for a genuine choice between the two options.
- Sufficient liquidity in the wholesale power market is essential to the EMR's success. It is not clear how the proposed reforms will deliver it. We would prefer to see proposed changes relating to liquidity included in the EMR rather than as a parallel work programme undertaken by Ofgem.
- The RO encourages suppliers to buy output from renewable generation. This incentive is removed in both the CfD and premium FIT models and its absence could see new projects exposed to a higher level of offtake risk.
- We agree that a capacity price mechanism has the potential to offer investors greater revenue certainty, but it may also undermine the case for commercial investment in peaking capacity. We would like to see greater policy focus on investment in ancillary services and flexible generation.
- While we understand the need for robust price setting, RenewableUK members are unanimous in opposing the use of auctions for FIT's. Tenders for support of renewable generation have a poor track record in other countries; will harm investor confidence; and do not support new entrants.

RenewableUK

RenewableUK is the leading trade association for the renewable electricity generation sector in the UK, representing over 670 companies in the wind, wave and tidal stream industries. The technologies we champion will provide not only the majority of electricity needed to meet renewable energy and carbon reduction targets by 2020, and over the longer term, their deployment represents major opportunities for growth in employment also. The EMR comes at a pivotal time for our industry, with many players poised to make not only significant investments in the development and construction of projects, but in plant and equipment also. Certainty in the policy environment is needed quickly to ensure that these investments are not derailed entirely or shifted to other countries. RenewableUK seeks constructive engagement with DECC and HM Treasury to ensure that the package implemented is done so effectively. We believe our input, which is based on the expertise and experience of our membership, can assist policy makers in making key decisions affecting the future of renewable energy in the UK.

Key Issues

What form of low-carbon support will work best? Some comments on the use of the CfD

RenewableUK has no objection in principle to the use of a fixed FIT, premium FIT or CfD FIT. The additional price stability each of these options could provide would be welcome. The Government should recognise, however, that the detailed design of whichever mechanism it chooses also carries with it the potential to slow down investment in renewable generation to 2020. We understand the attractiveness of the CfD but remain concerned that much of the detail in the package will result in considerable uncertainty and perceived risk on the part of investors. In particular, we are concerned that the basis risk, that between the index on which the CfD is struck and the income that can be realised by a generator is greater for wind plant than for the other low-carbon technologies. We also believe that the CfD, as outlined in the DECC Consultation, fails to provide a hedge against the policy risk associated with wind "cannibalisation" of electricity income[1] and against imbalance costs.

There are different types of risk inherent in the development, construction and physical operation of renewable energy projects. There is also market risk. The cost of capital for renewable energy generation, especially for offshore wind energy projects, is by and large 'front-loaded' in that it reflects development and construction risk. RenewableUK has argued for the retention of the RO on the basis that its continuation presents the least policy risk to project development. While we believe that careful design of the CfD, through the use of an appropriate liquid short-term electricity price index, could allow these shortcomings to be addressed, the resulting complexity and unfamiliarity of the support scheme (when compared to competing schemes elsewhere across Europe), may add to the perception of risks that are associated with the sector.

- RenewableUK recognises the need to cap costs for consumers, while ensuring project investments respond to a market signal, in which case the CfD may be a suitable approach.

- If the Government's intention is to de-risk low-carbon projects, this could be better achieved through a fixed FIT.

- Should the Government conclude that low-carbon technologies continue to bear balancing and policy risk, then we believe the simpler premium FIT, which is similar in form to the RO and thus more familiar to the market at present, would be an easier mechanism under which to raise the required finance than the CfD model.

There are advantages in using each of the types of FIT proposed in the Consultation for low-carbon generation. However, none of these options can be viewed in isolation, or as guarantees in themselves of increased market certainty to renewable generators. A premium FIT will not provide a buffer to electricity prices that reflect fuel price volatility while generators are required to contract into the market. In contrast, total income under a CfD is fixed at the strike price. While the generators remain exposed to differences between index of electricity prices used to determine the required top-up and income earned, the choice of index remains the core risk. For wind power basis risk is substantial.

[1] See Appendix A for an explanation of wind cannibalisation.

The difficulties a CfD FIT presents to wind energy generators:

- *Access to index* - a longer term average electricity price index is difficult for wind generators to access as they do not know with certainty the volume of their generation in advance. Selling power against long-term indices will expose wind generators to excessive imbalance exposure and greater basis risk between the price used to determine CfD payments and the market into which they are able to sell their power.

- *Transaction costs* - for non-Balancing and Settlement Code parties.

- *Counterparty risk* - the two-way nature of a CfD means that it places substantial risks on both parties to the CfD. In commercial CfDs this can require both parties to secure forms of credit to be held against the mark-to-market risk. As most wind generation is project-financed, whether at construction, or as refinanced utility projects after operation, the generator may have no recourse to a large balance sheet, and may have to raise funds for credit purposes.

- *Wind 'cannibalising' its own revenues* - as wind penetration in the market increases, electricity tariffs will increasingly be determined by the volume of wind generation in each period, with lower prices in windy periods and higher prices in non-windy periods, such that the average income of a wind generator can decline over time (see Appendix A).

What would be required to make a CfD FIT work for wind energy generation?

The market arrangements outlined in Consultation Document appear to be based on an assumption that generation is largely controllable. Wind energy and other types of variable generation do not have the luxury of being able to predict their output. Market rules which require generators to specify their output too far in advance of dispatch, coupled with penalties for generating more or less than the target, will act as a barrier to entry to wind power generators.

A price index based on a short-term, liquid short-term power market could reduce price risk. It would also eliminate exposure to the majority of balancing risk even if it does leave some imbalance exposure. We would recommend the use of a specified short-term market which, in turn, would create liquidity as low-carbon generators seek to sell through that index to minimise any basis risk. This may have the added benefit of reducing reliance on power purchase agreements (PPA's) between parties, as the route to market could be simpler.

Conversely, the disadvantage of using a price index based on a short-term, liquid market is that transaction costs and the complexity of accessing the short-term market may deter smaller players from participating, or significantly reduce their income through having to pay an intermediary trading entity to take this on.

Further steps to make the CfD work for wind energy could include:

- The Government acting as counterparty to CfD's, which would minimise counterparty risk and remove the need for the generator to post credit at additional cost.

- Improvements to the way imbalance charges are set, to minimise the residual risk that would remain if a short-term market is used to form the price index against which the CfD is priced.

- Central consolidation of wind and other variable generation technologies could be an option but it is not a requirement.

- Appropriately designed cash-out and imbalance mechanisms that do not impose an unnecessary penalty on variable output.

The implications of the EMR for the Northern Ireland Renewables Obligation

RenewableUK believes that the implications of the EMR for Northern Ireland should have been considered in the preparation of the proposals for market reform. The Northern Ireland Renewables Industry Group will be submitting a separate response to DECC outlining its concerns about the likely effects of market reform for the Northern Ireland renewables industry. RenewableUK supports this response.

Given the importance of the UK electricity market to the Northern Ireland Renewables Obligation, any significant change to the UK's electricity market will also have a major impact on energy policy in Northern Ireland. Before major change is made, the Government must give its close consideration what its proposed market reforms will mean for Northern Ireland generators operating in the All Island Single Electricity Market.

Consultation Questions – RenewableUK responses

__Current Market Arrangements__

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?

RenewableUK recognises that reform to market arrangements is required to accelerate the delivery of a low-carbon economy in the UK. We are strongly of the view that the Government must continue to engage with the renewables industry on the detailed design and implementation of whichever mechanism it decides to move to.

__Feed-in Tariffs__

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

We do not agree with the Government's assessment on the following items:

Hurdle rates: we do not accept Table 4's results for the reduction in hurdle rates for wind energy under a CfD. The table implies that a CfD FIT reduces risk to the same extent as a fixed FIT. This cannot be true if, as implied in paragraph 31, a CfD leaves generators exposed to short-term market prices (which a fixed FIT does not), and when a CfD leaves wind generators exposed to wind cannibalisation and to rising balancing and imbalance costs. These risks impose a much greater cost than the hedge to fuel prices a CfD would provide.

- We expect that for wind energy and other variable generation, any reduction in hurdle rates under a CfD would be of marginally greater magnitude than from a premium FIT but of significantly less magnitude than under a fixed FIT.
- *Investor attractiveness*: the statement in paragraph 36 that "fixed FIT and CfDs might be more attractive to a wider group of investors - in particular to smaller independent generators and institutional investors" is incorrect in respect of CfD's for both groups. Our feedback from both independent developers and from the financial community is that CfD's are seen as unfamiliar and with new risks, which have the potential to add rather than reduce costs.
- *Risk*: we disagree with the description of risk in Table 5 as it applies to wind and other types of variable generation. We do not believe that a premium FIT reduces policy risk for wind generators relative to the baseline under the RO.
- *Liquidity and offtake risk*: there is no consideration of the risks from removing the incentive for suppliers to purchase renewable output as it exists in the baseline. In the absence of a liquid electricity market, the present incentive under the RO strengthens the ability of independent generators to secure a route to market for their electricity generation. This is generally achieved through the use of PPA's, which also serve as the means of managing and partially mitigating exposure to balancing and imbalance costs:
    - under a premium FIT and CfD, generators will still need to secure a route to market for their generation and be required to manage their imbalance exposure but will be required to do so in the absence of an incentive for their potential counterparties to provide such routes.
    - unless a substantially more liquid market develops we believe these routes will come at a higher cost than at present, potentially offsetting any identified benefits in moving renewable generators from the baseline under the RO.

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

RenewableUK remains concerned that, without any detail on how the CfD will work in practice for variable generators, it is difficult to determine whether the Government's preferred option is truly workable. We do believe it is possible to design a CfD that would work for variable generation but that the 'devil is in the detail.' The challenge is to weigh the benefits from a modified CfD against the risk of adding substantial complexity to the support system. The lack of familiarity with CfD schemes among potential investors in low-carbon technologies, in addition to their complexity, may act as a barrier to attracting the required volumes of capital into UK-based low-carbon projects, with potential equity and debt providers preferring the simpler premium and fixed FIT's adopted by other EU Member States.

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?

As a general principle, risk is best allocated to the party best placed to manage it. Risk within the control of generators should be managed by them, whereas risk outside the generators' control should be transferred to another body, if that other body is better able to manage it. Under this principle, imbalance risk should be transferred to the SO best placed to manage energy flows nationally. The issue is that, while low-carbon generators may not have control and influence over these risks, it is not clear that the Government would do any better. However, while the electricity market remains illiquid, the cost-to-consumer argument for a transfer of these risks to the Government has merit.

We question whether the CfD as presented in the Consultation Document would remove long-term electricity price risk for generators. Under a CfD total income would be fixed according to a strike price. A generator may be exposed to differences between the index of electricity prices used and the electricity income it earns. For wind energy the basis risk can be substantial if the CfD is settled over extended time periods.

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?

Variable power generation cannot always respond to higher prices and generate greater volumes when prices rise. Exposing wind and marine generation to short-term price signals also leaves them vulnerable to wind cannibalisation, a risk that cannot be hedged in the market. It is important to note, however, that renewable generation technologies are not the only low-carbon types which are constrained in their response to short-term price signals. The Consultation assumes degrees of market efficiency for all forms of low-carbon generation under a CfD scheme that are untested.

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?

Ignoring the fact that every project has its own cost of capital (hurdle rate), we are of the view that the rates in Table 4 overstate the potential reduction in the cost of capital for wind projects from a CfD FIT. We believe the cost of capital reductions for wind energy projects under a CfD FIT listed in Table 4 are not accurate. The table implies that a CfD FIT reduces risk to the same extent as a fixed FIT. This cannot be true if, as stated in our response under Q3, the CfD leaves generators exposed to short-term market movements, to balancing risk and the risk of wind cannibalisation. Project cost of capital increases with risk and no two projects have exactly the same risk profile in this respect.

- There are a number of risks and costs that do not appear to have been considered in the assessment of a CfD:
    - index-basis risk
    - offtake transaction costs
    - counterparty credit requirements.
- The relative hurdle rate reductions for onshore and offshore wind in Table 4 seem counterintuitive:

    - we would have expected the implied impact on hurdle rates for onshore wind generators, which are exposed to market prices for over 50 per cent of their revenue, to be greater than the impact on offshore wind generators, whose exposure to market prices represents less than 40 per cent of their revenue. However, this is not the case in Table 4 for 'typical utility' projects, where the reduction for Round Three offshore wind (0.7 per cent) is twice that for onshore wind (0.3 per cent).

- The lower hurdle rates assigned to utilities are based on their current equity betas. Is this representative of their investments over the next 20 years?
    - the ability to raise finance on utility balance sheets is finite: it is becoming increasingly common for utilities to refinance operational wind projects on a non-recourse debt basis, placing most of these projects on the same footing as independently developed wind energy projects.

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 the existing investor base?

The critical factors in the availability of finance for low-carbon electricity investments are the returns available to low-carbon generators and the absolute and relative risks associated with these projects. These risks include:

- *Construction risk* from schedule over-runs and unforeseen capital costs.
- *Technical* risk in the operation and availability of capital equipment (the generator).
- *Cost rises* related to fuel (where appropriate) and operations and maintenance, and decommissioning costs.
- *Foreign exchange risk* for projects where most of the capital equipment is imported.
- *Market risk* related to volatility of income from the wholesale electricity market, predominantly driven by uncertainty over future gas, coal and carbon prices.
- *Balancing risk* related to short-term balancing costs and cash-out pricing for uncontracted volumes.
- *Liquidity risk* from uncertainty that there will be sufficient demand for output - to ensure that the generator can access a market for its generation at a reasonable cost - either directly or through a PPA.
- *Policy risk* related to future changes in support via carbon prices; to the form, structure and level of the FIT; and the ability of low-carbon generation to realise income from the wholesale electricity market as the carbon intensity of the marginal generator declines and as wind energy generation volumes become correlated to periods of lower electricity prices.
- *Policy risk* from the accounting treatment of the new FIT on the Government's balance sheet.

Fixed FIT

A fixed FIT removes exposure to market, liquidity and balancing risks. The familiarity of fixed FIT schemes, as used in other countries, may be attractive to some potential investors. The risks associated with fixed FIT's are in their design: fixed FIT's cannot respond to falling power prices, which leads to a greater measure of policy risk than is the case for other forms of support, where only the resource cost (net of the income from the wholesale electricity market) is visible.

CfD FIT

The CfD FIT proposed in the Consultation Document has the potential to remove market price risk from wind generators but could still leave them exposed to liquidity, balancing and policy risks.

Volume risk is not overcome in the absence of effective liquid markets. To manage their overall risk exposure wind energy generators would need to contract bilaterally in the market for consolidation and balancing services and for long-term price hedges (floors), as they do presently under the RO. A two-way CfD FIT also introduces credit risk that may require both the generator and the offtaker to post credit to cover the mark-to-market risk in the CfD. For financing purposes, the generator's credit requirement could increase the cost of finance that needs to be raised, while the counterparty risk may limit the number of suitable offtakers.

It ought to be possible to design a CfD that would mitigate much of the liquidity, balancing and policy risks (indexed to very short-term spot markets, with the Government as the counterparty and with capped imbalance). However, this is also likely to result in complexity, whereby the CfD may be perceived as relatively risky by financiers due to their lack of familiarity with it.

Premium FIT

A premium FIT may not provide a hedge to market, liquidity, balancing or policy risk. To manage their risk exposure, wind power generators would need to contract bilaterally in the market for consolidation and balancing services and for long-term price hedges (floors), as they do under the RO. However, the relative simplicity of concept and international familiarity with the premium FIT approach may mean that, for financiers, it is the most acceptable of the FIT options outlined by DECC.

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?

Fixed FIT

Utilities

The sale of output to a central agency, as occurs under other fixed FIT programmes, is viewed by participants in the UK market as too interventionist.

New entrant generators

For offshore wind and marine energy technologies, where there remains substantial uncertainty over the development, construction and management costs of these technologies, the lock-in of a fixed income stream under a fixed FIT may reduce the cost of debt by reducing the overall risk profile of the investment. The disadvantage of a fixed FIT in this case, however, is that it may be unattractive to equity investors who may perceive a lack of upside to returns on their investments.

CfD FIT

New entrant generators

A CfD FIT has the potential to remove market price risk from wind and marine energy generation but could still leave projects exposed to offtake risk, in the absence of an incentive for suppliers to purchase their output. However, it may be possible to design a CfD that would mitigate the liquidity, balancing and policy risks for wind and marine technologies by indexing it to short-term spot markets and with the Government acting as the counterparty.

The impact of CfD's on contract negotiations and relationships with electricity suppliers

Most renewable generators currently choose to contract bilaterally with traders or suppliers in order to gain to access the electricity market, to consolidation and balancing services and to sell benefits such as Renewables Obligation Certificates (ROC's) and Levy Exemption Certificates (LEC's). This applies equally to independent generators and to projects developed by utilities that have since been refinanced as independent entities. The contracts may vary from long-term fixed price PPA's to short-term routes to market, that pass market and imbalance costs through to the generator in the form of a discount to market price.

Wind and marine energy generation, because of their variable generation profile, present greater imbalance and 'shape' risk than baseload generation, and are therefore less attractive to a supplier as a procurement option. Wind and marine energy generators also sell their output at a discount, to sign a PPA, with smaller discounts as the PPA provides more hedging to imbalance or to market price. Longer durations also transfer additional risk from generators to offtakers.

There is concern that, under the CfD FIT, wind and marine energy generators may find it harder to make contracts with suppliers. While the RO may not have provided a strict obligation to purchase power, it has provided a significant incentive.

- To ensure that renewable energy generators are able to continue contracting bilaterally under a FIT, it has been suggested that a new incentive be put in place to encourage suppliers to procure low-carbon electricity, potentially through suppliers' fuel mix declarations and that prescribe declining carbon intensities. What is unclear is the nature of the penalty that would apply.

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 vital to the success of the CfD. Liquidity, in the context of a CfD mechanism, will be greatly influenced by the choice of index. The most appropriate index could be a half-hourly post market or four-hourly electricity forward agreement, which should minimise exposure to balancing risk and mitigate wind cannibalisation. However, this would introduce process issues for both generators and the CfD administrator and if large volumes were traded very near to gate closure, this would introduce risk for suppliers who have open positions.

- For a CfD to provide an effective price hedge the generator must be able to sell its power into the indexed market; otherwise it will be exposed to basis risk between the value of the income it receives and the market value used to settle the CfD.

- If liquidity is not improved in the electricity market, low-carbon generators may be exposed to high transaction costs in accessing the market.

Setting a benchmark electricity index that can be accessed by all forms of low-carbon generation will assist in the creation of market liquidity, by concentrating traded volumes in this market. However, if the market remains illiquid, this benchmark index may have to trade at a lower price than other traded electricity products, in order to make it attractive to suppliers to purchase from it. In this case, the cost of illiquidity will fall on the consumer through the higher premium being paid between the market price and the strike price, and/or the indexed power market may trade at a discount to other sales routes.

The creation of sufficient liquidity in the electricity market may require structural changes that can only be brought about through primary legislation. While Ofgem has given its undertaking to guarantee liquidity, even if this meant forcing liquidity into the market, this approach has the potential to disrupt current PPA's and to add to investors' perception of policy risk. DECC appears too reliant on Ofgem to provide solutions to offtake risk.

- RenewableUK would prefer to see proposed changes to the existing market arrangements brought within the EMR process rather than being run by Ofgem in parallel workstreams focussed on new entry by small suppliers.

If the Government were to move ahead on the assumption that Ofgem's work will be translated into action, we are concerned, as it strikes us as a high-risk strategy. We would point to the experience of the Transmission Access Review as a precedent that does not inspire confidence in this regard[2].

- If market liquidity is to remains a key plank in the EMR process then we believe that DECC will have to legislate in this area.

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[2] Ofgem led an industry process in an attempt to agree to reforms in the arrangements to connect to the transmission system. After many months of negotiation and inability to build consensus, Ofgem handed the issue over to DECC to decide, using legislative powers.

Even if there is sufficient liquidity for offtake risk to be satisfactorily dealt with, there may be practical issues with using a short-term market to set the index against which a CfD would be priced. In order to access this market, generators would have to join the relevant power exchange. Intermediaries could be used, but at a price, thereby eroding the value of the FIT.

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

We acknowledge the potential for using availability as a measure for payment, to solve the problem of negative pricing (as low-carbon generators paid in this way would not be incentivised bid down below zero in periods when generation needs to be constrained). However, there are a number of issues with this approach which make it appear unattractive:

- Use of availability as a basis for payment increases the complexity of the system, further deterring wider participation from new entrants.

- Renewables targets in the Renewable Energy Directive are set on the basis of energy volumes and a FIT set on the basis of output is best aligned to this.

- Determining availability for wind energy, which is based on technology and resource availability, is complex whereby using output would be simpler.

- There may be an increase in political risk under availability payments - there is a risk of a consumer backlash against the perception that they may end up 'paying for something they may not even be using.'

For these reasons, we believe it would be better to pay the FIT on the basis of output only. It would certainly be helpful to have a mechanism to deal with the issue of negative pricing, but we do not believe availability-based payments are the correct way to deal with this.

<u>Options for Market Efficiency and Security of Supply</u>

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

We support the Government's aim of encouraging larger flows of investment into low-carbon generation, while ensuring security of supply. We agree that a capacity price mechanism has the potential to offer investors in eligible plant greater certainty in revenues, thereby improving the investment case; however, we are also concerned that there is a risk that a capacity price mechanism may depress energy prices. This issue needs to be addressed in the detailed design of any capacity payment mechanism.

RenewableUK also believes it is important, in the context of balancing the advantages and disadvantages of capacity payments, to make a distinction between what capacity is and can deliver and the need for flexibility in the system, between:

- Capacity - the need to secure the availability of sufficient plant margin to meet demand requirement; and

- Flexibility - the need to provide system control, stability and balancing in the context of variable and sometimes rapid changes to demand and/or generation.

Capacity matters when there are periods of:

- o low output from variable renewable generators
- o low plant availability due to generation trips and outages
- o low interconnection availability due to planned and/or unplanned outages
- o network circuit failure limits supply of otherwise available plant and/or interconnection
- o exceptionally high demand

Flexibility matters when there are:[3]

- rapid changes in demand
- forecast errors in demand prediction
- rapid changes in output from large single unit generators
- rapid changes in the output from variable renewable generation
- forecast errors in predicting outages from variable renewable generation
- rapid changes in output or demand due to network circuit failure.

The provision of energy flexibility is required to meet the increasing system needs for power ramping, rapid response, short run times and low cost start up and shut down. These services function in addition to other ancillary services such as reactive power, voltage response and frequency response. EirGrid, which has experience of running its system on 50 per cent wind power and of capacity mechanisms, has informed us it would like to see generation earning less capacity revenue in future in the Republic of Ireland in favour of increased payments to ancillary services. However, EirGrid is fettered in its ability to make this change due the legacy of capacity payments already made.

In the short term, before any significant new flexible and peaking generation capacity is brought on line, the increasing penetration of renewable technologies will result in lower load factors and more frequent start-stops for existing generation, particularly for combined-cycle gas turbines. These plants will rely more on peak power prices and ancillary services contracts for income, which will help to prevent closure and make them available as capacity. With this relatively inflexible nuclear and renewable capacity build, it will become imperative for the System Operator (SO) to be able to contract flexible plant to meet operational needs.

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

Security and reliability of electricity supply: capacity payments

As per our response at Q19, the EMR proposals do not differentiate between two separate challenges - of ensuring the provision of sufficient capacity as opposed to the provision of system flexibility.

Flexible generation/demand-based solutions could address both the capacity and flexibility issues, potentially making the untargeted capacity payment redundant and helping to reduce cost for UK consumers. As power systems evolve and decarbonise, there will be many more operating scenarios (high/low wind, high/low demand, high import/ high export), which the SO must manage. In order to maximise the growing contribution of renewable generation, SO requirements will also change. We do not support technical requirements on the SO being locked in through legislation but we recognise that a Standard of Supply needs to be defined and a clear owner identified.

Reforms to the balancing arrangements

Ofgem's proposed review of cash-out needs to occur in the context of the EMR and must produce a mechanism that does not disadvantage variable renewable energy generation. However, as stated in the response to Q19, we would have concerns about any move to the marginal-cost pricing of the cash-out. Far from being more 'cost reflective,' it is likely to lead to significant over-recovery of imbalance payments (compared to the balancing costs incurred by the SO), imposing substantial cost on all participants and on wind energy generators in particular. Ultimately it is likely to result in all wind energy projects needing a higher level of low-carbon support to become economic. Marginal-cost pricing may also encourage all parties to hold a 'long' position, in an attempt to self-balance, imposing a net cost on the market. It will act as a barrier to entry to independent suppliers and generators, as it favours portfolio players which are better able to manage their energy account position.

The centralisation of balancing for wind and other variable power generation technologies could be an efficient solution for minimising market exposure. Commercial consolidation services capable of delivering this are already available in the market.

[3] Rapid change numbers taken from National Grid: http://www.nationalgrid.com/NR/rdonlyres/32879A26-D6F2-4D82-9441-40FB2B0E2E0C/39517/Operatingin2020Consulation1.pdf

- The implied benefit of consolidating a large volume of wind energy generation will need to be evaluated closely - any increase in marginal cash-out pricing would impose an additional deadweight cost on wind generators, to which they cannot respond, irrespective of the degree of consolidation.

At present, there is only one reserve buyer, the SO, but we can foresee a situation where there might be multiple buyers. Under this scenario, distribution networks are likely to need their own Distribution System Operators as we move to a Smart Grid future, and there may be opportunities for multiple Transmission System Operators, particularly offshore. A reserve market could develop, fostering competition and innovation, and that includes new demand side and storage services.

- We welcome the creation of a reserve market, but only in the context of structural reform.

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

In theory, a carefully designed and targeted support scheme should not have an impact on prices in the wholesale market. In practice, however, the provision of capacity support may distort price setting. Peaking plant, whose fixed costs are recovered through the capacity mechanism, may be able to participate in the market at short-run marginal cost, undercutting merchant providers and potentially diluting price signals at peak times. This could reduce the value that all generators are able to earn from generating at peak periods and may dissuade commercial investment in peak capacity outside of the capacity mechanism, perversely increasing the need for the capacity mechanism to expand capacity. If contracted capacity bids in at short-run marginal cost, and this is reflected in imbalance, then imbalance prices would be expected to be smoother, with a corresponding dampening of wholesale prices too. This would affect the energy revenue stream potential. The degree of impact would depend on the volume of contracted capacity and the frequency with which it is called.

Contracted capacity that bids at long-run marginal costs has the potential to expose wind energy generation to higher imbalance prices. This might not be the case if the contracted capacity is generally called at times when wind output is low, when wind farms have limited exposure imbalance (provided that low wind output is forecast and reflected in contractual positions); however, it may be that generally more volatile imbalance prices translate into greater balancing risk exposure in PPA's.

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.

If the Government does decide to introduce a capacity payment mechanism, we believe the following conditions need to be in place:

- *A central body responsible holding the responsibility* - the SO should have responsibility for ensuring sufficient capacity with all the appropriate checks and balances in place.

- *Volume based, not price based* - this is feasible but there needs to be more work done to determine the appropriate volume for the capacity margin. There is insufficient evidence to support the 10 per cent capacity margin assumed in the analysis in the Consultation Document, which the cost benefit analysis appears to conclude is excessive. There is also a lack of clarity over what the 10 per cent includes: is wind capacity factored into the equation? If so, at what level of capacity credit? It is also not clear if a probabilistic analysis has been undertaken to arrive at an appropriate margin figure. The required capacity margin should be set with reference to the probability of energy going unserved and the value placed on that energy by consumers.

- *A targeted mechanism, rather than market wide* - we agree that a narrowly targeted mechanism is preferable. Market-wide mechanisms may enable capacity prices to be captured by high load factor, low-carbon technologies, which may reduce the level of low-carbon support these technologies need through the FIT, giving them an advantage over wind energy generation. However, as these technologies may be inflexible, they may not warrant the additional support.

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?

We note the Government's reference to demand management and energy efficiency in the Consultation Document. We welcome this emphasis; however, we would also like to see further detail from the Government on how its proposed capacity mechanism will act on demand. Putting any capacity mechanism in legislation carries with it the risk that it could weaken incentives for demand-side management and technological innovation.

- It is likely interconnectors will play an important role in providing capacity as well as in facilitating the future export of energy from renewable generation and smoothing electricity price variations. The proposed capacity mechanism could discourage such investments.

24. Which of the two models of targeted capacity mechanism would you prefer to see implemented:
• Last-resort dispatch; or
• Economic dispatch.

If a capacity mechanism is implemented, we would support last-resort dispatch, as it is less likely to distort the electricity market price.

RenewableUK is opposed to the economic dispatch option, as supported peaking plant whose fixed costs are recovered through the capacity mechanism, may be able to participate in the Balancing Mechanism and electricity market at their short-run marginal cost. This is likely to dilute price signals at peak times and is likely to reduce the value available to all forms of generation operating during peak times, which, otherwise, could be well placed to capture peak prices.

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

We do not support any locational element in capacity pricing for the following reasons:

- It confuses the need for capacity to meet a shortfall in energy with locational signals to mitigate network constraints. Locational signals already exist through TNUoS charges to encourage siting of generators based on peak flows.

- Locational capacity payments add additional complexity, reduce liquidity and may penalise plant located away from demand which is able to meet capacity needs.

- Locational capacity pricing has the potential to create a conflict of interest between the role of SO to procure capacity and its role in managing transmission constraints. Experience with the cash-out regime is that it has proven exceptionally difficult to distinguish actions taken by the SO to manage constraints from those aimed at balancing.

Analysis of Packages

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?

RenewableUK does not have a position on the emission performance standard. We have no objection in principle to the proposals for a fixed FIT, premium FIT or the CfD FIT; however, it is essential that any proposal for CFD's takes into account basis risk, offtake risk, and liquidity risk.

RenewableUK recognises the need to strengthen the long-term carbon price signal and has stated this in its submission to HM Treasury on the carbon price floor. Greater confidence in the carbon price beyond 2020 is required, given the uncertainty over the status of the EU Emissions Trading Scheme after that date and the long-term nature of low-carbon investments. We believe any carbon floor price should operate on the principle of increasing support. It should start at a low level and rise gradually to provide confidence in it as a genuine means to support and as projects come online in the latter part of this decade.

- HM Treasury needs to ensure that carbon price support delivers a 'bankable' price trajectory. This means the Climate Change Levy should be adjusted so the overall carbon price remains in a narrow range, with a visible long-term trajectory.

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

We believe a premium FIT may be more effective than the CfD FIT in catalysing an increase in renewable energy's share of low-carbon generation to 2020 and beyond. It is the easiest-to-understand of the FIT's proposed in the Consultation in that it resembles the RO. However, as stated previously, there are issues around offtake, liquidity and the lack of an incentive for suppliers to purchase output from renewable energy generation that are not addressed in the Consultation.

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?

All economic reform implemented on the same scale as that proposed in EMR carries with it the risk of unintended consequences. The Government's proposal for a capacity mechanism, if carried out, may result in the retention of capacity that is neither flexible nor responsive. The proposal would appear to overlook the needs of both the networks and the system operators. This is because the shape and function of ancillary services will change over time and will depend on the changes in the generation mix and on different operating scenarios.

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

For wind energy generators the critical element of the package is the choice of an effective FIT mechanism. While we have concerns that the capacity price mechanism could have a negative impact on the electricity market, these concerns are less under the preferred package (centralised targeted approach) combined with last resort dispatch, than the alternatives proposed. We would, however, recommend a different approach, as set out in our responses to Q19-25.

Implementation Issues

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?

The main implementation risk for the CfD is that it is too complex, or perhaps more importantly, perceived to be more complex than systems in other countries, which could then deter investment in renewable energy in the UK. Either an average price index is used, that hedges against market risk but leaves variable power producers open to basis risk, or a short-term price index is used that is significantly more complex and expensive to operate and impractical for smaller generators. The CfD may also require the establishment of new agencies to administer its operation.

The implementation risk of the premium FIT is likely to be less than that posed by the CfD. The premium FIT also presents a lower-risk option in the face of calls at the European level for the harmonisation of support for renewables, with premium FIT-type models being discussed.

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?

Auctions

RenewableUK members are strongly of the view that auctions to set the level of support for low-carbon generation would act as a major barrier to investment in variable generation.

Auctions increase development risk

The most serious implication of auctions is their impact on project development risk. At present, a renewable developer can invest in all the processes required to gain consent and grid connection, in the knowledge they can access the RO and with confidence about the level of reward available. With an auction system in place, the developer cannot have confidence that support will be made available to their project, since they may fail to secure a contract through the auction process. This is because developers cannot be clear what level of support their projects will receive from an auctioning process. It is possible that developers will focus solely on the cheapest projects in their portfolio, or abandon project development altogether.

Offshore wind developers in Round Three are likely to be adversely affected. These developers have signed Zone Development Agreements with the Crown Estate which commit them to taking forward these zones in line with set timetables, with consequences for non-compliance. They did so in the expectation that they would be able to access support freely through the RO. Auctions have the potential to leave Round Three investors with stranded assets and to impose significant losses. The Crown Estate can terminate a Zone Development Agreement if the developer fails to deliver against the agreed milestones or it has step-in rights over the project. Any delay or uncertainty as a result of the use of auctions could result in developers losing their assets. Having made significant investments to bring projects to consent, developers could be left with nothing at the end of the auction process. This outcome would not see the UK become an attractive place to invest in project development.

There are also considerable transaction costs to participating in tenders which could deter smaller players from taking part. If projects are expected to enter tenders early, ahead of planning permission, then developers will have to devote resources to both consents and contracting at the same time, reducing the number of projects they can work on. If tenders are entered late, after planning, then developers will be expected to sink costs into projects without knowing what rewards they will get, if any. If, in order to deter unrealistically low bids, there are significant penalties for non-delivery, then again this may have a significant impact on small developers' willingness to participate.

Tenders will also introduce a stop-start element to the renewable energy sector, with developers having to wait until the next tender round before proceeding with projects. This makes business planning difficult and leads to inefficient use of resources. Under the Non-Fossil Fuel Obligation (NFFO), uncertainty about when auction rounds would be forthcoming was one of the key difficulties with that system. This issue could be reproduced in a new system if tenders are postponed until there are 'enough' bidders to make up a meaningful competition. In general, auctions add another step into the development process, further delaying delivery of capacity.

Auctions do not assist in bringing still maturing technologies to market. The NFFO experience for onshore wind, with its emphasis on cost reduction before technology constraints had been fully worked through, led to unrealistic bidding and under-delivery. It also undermined the development of a UK manufacturing industry during the 1990s, with the result that the economic benefits of developing these resources went elsewhere.

- We believe that auctions designed to set support levels would severely reduce the attractiveness of the UK as a development destination, particularly in comparison to countries that do not use competitive processes in their support mechanisms.

- If the Government's key objective in the EMR is to 'unlock investment' we do not see how this will be achieved through the use of auctions.

The NFFO precedent does not support the reintroduction of auctions

With its experience in the 1990s of the use of auctions under the NFFO system, the renewable energy sector does not believe that auctions reveal 'true' prices, with the result being large-scale non-delivery of contracted projects. In total, around 30 per cent of contracted NFFO wind capacity was delivered, with NFFO 5 delivering as little as 2 per cent of contracted volume. For the most part, this was due to bidders, in the face of uncertain costs of a new technology, bidding low in order to secure a contract which they ultimately did not deliver on. The NFFO experience for onshore wind, with an early emphasis on cost reduction before the technology had been worked through, led to unrealistic bids.

Auctions have not worked elsewhere

Evidence from other countries where this approach has been tried is mixed. The Netherlands is quoted in the Consultation Document, but its tender in 2009-10 represents a clear case of market failure. Lower bids were awarded, in which the true risks in development and delivery were not priced. Winners of the tender came to be seen as higher risk ventures. There was also great investor uncertainty over the future availability of the subsidy on offer. Ultimately, The Netherlands offshore wind tender failed to meet the target of 950MW by more than 200MW, with 12 projects receiving consent and site concession prior to concessions being awarded but with permits that are set to expire in 2012.

France's experience in 2004 fared little better. There were four criteria: PPA price, technical and financial capacity, environmental impact and potential conflict with other users, with the greatest weighting being given to PPA price. Many bids were unable to secure consents after having been awarded. The French Government was unable to revise its criteria post-award and only one project was successful - it is still awaiting the outcome of pre-construction permit appeals seven years after being awarded. The outcome was reduced investor confidence in the French market and an industry brought to a standstill.

The evidence is clear. Competitive tenders have not delivered. These tenders favoured higher risk but ostensibly cheaper bids. There was no flexibility to revisit more conservative bids that were not successful initially, when lower priced bids failed to deliver. There were insufficient penalties for non-delivery, nor enough attention given to bidders' track record and finances.

Technology neutral or specific

The proposed low-carbon support mechanism is intended to bring forward a mix of technologies with varying characteristics, in which case differentiation in support is logical. Given the range of renewable energy generation technologies, it may be desirable to group technologies in reasonably broad bands, although certain forms of generation such as nuclear and offshore wind would most likely merit a specific band each. We believe the proposal to have single competition for support with technology 'adders' would be difficult to manage, especially as it would include the disadvantages of auctions alongside an evidence-based process to set the technology-specific additions.

Our clear preference is for all support levels to be set using an open, evidence-led approach, as is used in setting the banding levels for the RO. We believe that this has generally worked well. Any such system for a new mechanism would need transparency, with independent advice sought by the Government, and the result subject to scrutiny and review by the industry and other stakeholders. How the evidence is gathered and analysed is important, with transparency needed around how key variables such as capital costs will be extrapolated into the future. If the Government chooses to use a CfD mechanism for low-carbon support, then clarity will also be required on how the strike price will be calculated for differing technologies, given the basis risk issue - where generators such as wind may end up earning less income than the chosen index from which the top-up payments are calculated.

The Government should set a level of support that incentivises an appropriate level of build. The purpose of regular reviews should be to monitor whether the rate of this development is as expected, adjusting support as necessary. We do not believe that this means of setting support will lead to an unsustainable build of any particular technology, so long as the Government applies lessons learned from the band-setting process in the RO.

- Given clarity on the levels of capacity from each technology, it should be possible to set levels of support so that appropriate amounts of development take place.

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

If the CfD is adopted, some kind of central agency will be required to act as the counterparty, to minimise counterparty risk and to obviate the need for generator to post credit at an additional cost. In parallel with the wider market reform process, DECC is examining the role of Ofgem. RenewableUK believes that Ofgem has focused too narrowly on network operation and has not taken into sufficient consideration the impact of grid availability and cost on the ability of the UK to meet targets for renewables and carbon emissions. To target flexibility and grid availability, and to promote investment in flexible plant, National Grid would need to let contracts of a longer duration that one year.

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?

The best way for the Government to minimise the possibility of there being unintended consequences from the FIT or targeted capacity payment mechanism would be for it to maintain an open dialogue with the renewable energy industry on the detailed design and implementation of these mechanisms.

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

At the end of 2010, 3.87 GW of onshore wind and 1.34 GW of offshore wind were operating in the UK. An additional 1.36 GW of onshore and 1.15 GW of offshore wind were under construction. Approved capacity in onshore wind was 3.73 GW and 2.7 GW in offshore wind, while capacity in the planning system (not consented) was 6.94 GW for onshore and 2.26 GW for offshore wind.[4] There is significant risk of a hiatus in investment in capacity that is approved and planned during the transition to the preferred package, should there be no quick resolution of uncertainty surrounding its implementation.

The CfD may assist in stabilising revenue flows over the long-term, but this is a moot point if, over the next decade, planned investment does not go ahead or has to be refinanced at higher margins, due to perceived risk and uncertainty over the implementation of many of the EMR's core proposals.

The transition to the CfD could raise legal issues between developers and lenders, in particular the risk that if, existing long-term PPA's are terminated due to change of law, this would then act as a trigger for default by borrowers. Much will depend on the impact from the EMR on existing renewable deals: if necessary, if their economic value cannot be salvaged via contract amendments, then the possibility of default by borrowers cannot be ruled out entirely.

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?

RenewableUK members have expressed their concern over the end date of April 2017 for accreditation under the RO. Our response to Q36 sets out the reasons for this. As a result we think a later stage for RO qualification for projects planned before April 2017 would help to avoid delays to planned investment. This could be administered in the same way as occurred with the banding down of landfill gas generators. New landfill gas generators were able to preserve 1ROC/MWh, rather than 0.25ROCs/MWh, if they received preliminary accreditation before April 2009, followed by full accreditation (at the point of commissioning) before April 2011. This precedent could be used for allowing projects that receive pre-accreditation by 31 March 2017 to qualify for RO subject to achieving full accreditation by 31 March 2020.

The status of earlier phase NFFO projects does not appear to have been addressed. Grandfathering to 2027 applies to projects that have a current RO contract; but at present there does not seem to be any provisions for NFFO 5 (and possibly NFFO 4) projects which finish their contract term after April 2017. NFFO 1, 2 and 3 projects have already moved onto the RO scheme. It would be inequitable for NFFO 4 and 5 projects to be left without any provision for continuation of support. As it stands now, with the cut off date set in the EMR set at 31 March 2017, all commissioned NFFO 5 projects that started after 1 April 2002 are in an insecure position. Clarification on the status of NFFO 5 projects under grandfathering of the RO has been sought by some RenewableUK members.

[4] *The UK Wind Energy Database 2010*, RenewableUK

We also note the potential impact of change on income from the sale of LEC's currently earned by UK renewable energy projects in the RO. Our understanding, from discussions with HM Treasury, was that this system will be grandfathered. This is critically important because most of the renewable energy projects financed in the UK under the RO have been project financed under long-term contracts in which the LEC revenue was included.

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.

The key issue with the transition between the RO and the new system of low-carbon support is that the RO is accredited to projects after the point of first generation, whereas the new mechanism is granted earlier in the project cycle, presumably at financial investment decision (FID), when the developer signs contracts for major equipment. Accreditation at FID can work if there is clear guidance on its definition, on which contracts signed constitute FID. However, if the RO is being closed to new entrants in April 2017, then investment decisions need to be made well in advance of this date if the scheme is to be accessed in time. At the very least, developers must be able to sign the new contracts before 2017, even if they cannot be activated until that date.

The long lead-time for many projects, especially in offshore wind, means that an RO accreditation deadline of 2017 may exclude a number of offshore wind projects currently under development. An offshore wind farm in development that elects to be in the RO will probably have to make that decision by the end of 2013. This means that any alternative to the RO needs to be clearly in place by that date, or project deployment will slow down because projects will not be assured of reaching the 2017 accreditation date. As at Q35, this issue could be solved by granting an initial pre-accreditation status to any project that intends to use the RO and has commenced construction by the 2017 cut-off date. We believe developers should be allowed to choose between the two systems.

- It is possible that developers could decide to invest in a project on the understanding that it would enter the RO, and then opt to sign a FIT contract later, but that option may be limited to players financing projects from their balance sheets.

- Developers using project financing would have created a contract structure around the RO which would have to be unpicked and refashioned in order to change schemes in mid-build, which in turn leads to risk of legal issues under PPA's and the possibility of default clauses being triggered in loan agreements.

The effective window of opportunity to choose would be even shorter if FIT system implementation were to be delayed. The Government is projecting that the contracts will be available to sign in April 2013, but this is only 24 months away from the end of the Consultation, and the White Paper must be issued, primary and secondary legislation passed, and new structures created before the new system is implemented. The risk here is that the April 2013 date slips and the FIT will not be available until 2014. For projects that take a long time between investment decision and generation, there will be little or no effective choice unless there is some flexibility about projects' ability to enter the RO around the April 2017 cutoff.

It should also be noted that, under the transition arrangements proposed, large-scale projects may not receive 20 years of support from the RO for all the turbines in the project: the end of the RO in 2037 could result in some turbines receiving as little as 15 years of support. This will make the economic case under the RO very difficult to prove for major projects seeking FID in 2013-14 and demonstrates that, in practice, there is unlikely to be a realistic choice of mechanism for these developers.

- We urge the Government to extend the RO beyond 2037 for this type of project, to ensure that there is no delay in financial investment decisions in the period 2013-2015, to guarantee that support under the RO is sufficient for large scale, offshore wind projects.

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?

RenewableUK's preference would be for non-grandfathered technologies to be moved to the new FIT scheme. This would not only remove the need for banding reviews for the vintaged RO, it would make forecasting the number of ROC's in the market easier, which would be beneficial when using headroom to set the Obligation level post-2017, which is our preference.

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

It is feasible to continue with the current mechanism to set the Obligation using both target and headroom. We recognise, however, that up to the end of the RO in 2037, it is possible projects still in the scheme will be over-rewarded if the Obligation is not allowed to fall to zero. The second option (using Calculation B only) does allow the target to fall towards zero if there is little forecast renewable output within the remaining RO group of projects. We therefore believe that this is the only appropriate way to set the Obligation from 2017.

Converting to a fixed ROC

RenewableUK believes that fixing the price of a ROC for existing and new generation would be very unhelpful. Fixing the price of a ROC has the potential to disrupt hundreds of PPA's that are currently in force, which, in turn, would require hundreds of bilateral legal negotiations to determine the financial winners and losers. This move would demonstrate a damaging lack of commitment from the Government to genuine grandfathering.

We are open to the possibility of a hybrid system, with a move to fixed ROC's at a date between 2017 and 2037, but we would need to see a specific proposal before being able to comment one way or another. Specifically, this proposal should not be implemented at any date where any PPA that is in effect now could be damaged. This would suggest that the earliest possible date for the implementation of the fixed ROC, if at all, would be around 2030.

- It would be very helpful for the White Paper to state that all the RO's constituent parts - the indexed buy-out price, 10 per cent headroom and recycling, and banding - will be retained into the future. This would give confidence to investors that the system will be grandfathered in its entirety.

Any changes in law must respect existing contracts. A large number of existing RO projects have been financed using long-term project finance provided by the banks and rely on the signing of 12 to 15 year PPA's with the 'Big Six' utilities, generally. Effective grandfathering will prevent the termination of existing contracts between power generators and the major utilities. Grandfathering needs to take into account the fact that most project financing loan documents allow the lending banks to declare loans to be in default in certain circumstances, typically:

- Change in law which leading to adverse material effect (on the economics of the investment).

- Termination of any contract on which the project financing is based, specifically including the termination of any power sales contract (PPA) between a generator and utility.

Appendix A - Wind cannibilisation and electricity market capture prices for wind generators

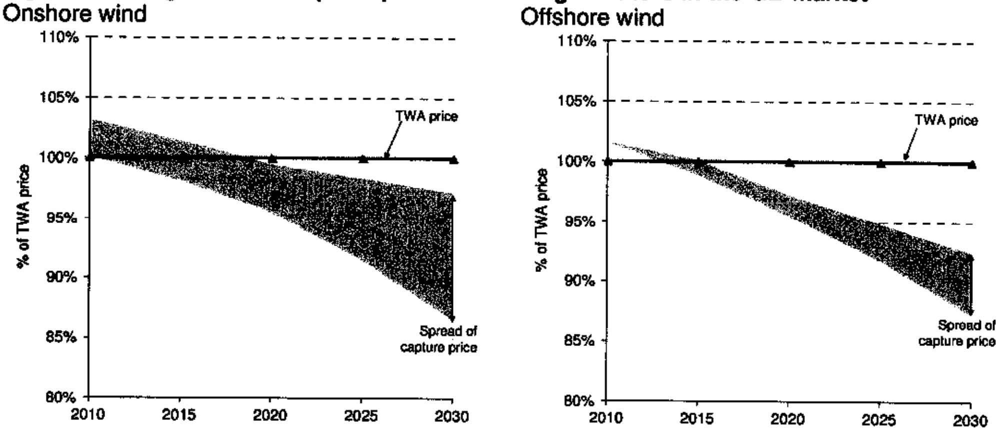
Many renewable energy technologies exhibit variable generation profiles, including wind, run-of-river hydro, tidal, wave and photovoltaic solar energy, and may also lack predictability or have very little control over the periods in which they generate. As such, the price these generators receive in the electricity market may differ substantially from the time-weighted average price (TWA) that a baseload generator may receive.

Looking ahead, the expected growth of variable renewable power will increase the level of volatility in the electricity market, which, in turn, will affect the value of variable output in the market. For example, at the high levels of wind penetration envisaged in the Government's *Renewable Energy Strategy 2009*, the volume of wind generation could even become a determinant of wholesale electricity:

- During periods of high wind generation there would be downward pressure on wholesale electricity prices, as wind displaces higher-cost generation sources; and
- During periods of low wind generation there would be upward pressure on wholesale electricity prices, as higher-cost generation sources would be forced to operate.

In the event that high levels of wind penetration are achieved in the UK, the generation-weighted average (GWA) price for electricity produced by wind generators could be expected to fall below the annual TWA electricity price in the longer term. This effect is sometimes referred to as "wind cannibalisation."

Figure 1 – Range of GWA capture prices for wind generators in the GB market



Source: Pöyry Management Consulting

Figure 1 presents results from Pöyry's *Impact of Intermittency*[5] study and shows the relationship between the GWA capture price of onshore and offshore wind generators and the TWA baseload price, at five yearly increments. The GWA price is shown as a proportion of the TWA price, as the results are fairly consistent across various scenarios for the level of underlying electricity price.

- Over time, the wind capture price is expected to reduce, from slightly above TWA prices in 2010 to significantly below by in 2030. The extent of this effect varies with the installed capacity of wind and other technologies.

The wind capture price varies significantly by project, illustrated by the shaded areas in Figure 1, and is driven by:

5 *Impact of Intermittency. How Wind Variability Could Change the Shape of the British and Irish Electricity Markets.* Summary Report. July 2009. Pöyry Energy Consulting. http://www.poyry.com/linked/group/study

- Location - the greater the physical proximity of a wind farm to the notional centre of the UK's wind energy production, the more highly correlated the output of that wind farm will be to aggregate wind output and the greater its inverse correlation to power prices.

- Load factor - the greater the load factor of the wind farm, the nearer the capture price will be to TWA prices.

The increasing divergence between GWA and TWA prices over time is because price separation is dependent on the amount of installed intermittent capacity, which is assumed to increase over time. In a more extreme scenario considered, with more rapid renewables deployment and a greater nuclear capacity, the wind capture could fall further over time - to around 75 per cent of TWA prices by 2030 for some projects.

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