Electricity Market Reform

Consultation by DECC

Response by E.ON

Summary

We recognise that Government needs to provide stronger incentives to build new low carbon generating capacity to meet the UK's specific climate change targets. Interventions should be consistent with the EU ETS, which the Government should continue to work to improve as an investment driver.

A Feed in Tariff (FIT) based on a Contract for Difference (CfD) is likely to be more effective than a premium FIT (PFIT) in reducing the market risks associated with new low carbon investment, particularly for new nuclear power or CCS-fitted plant, although the effect on renewable investments supported by the Renewables Obligation (RO) may be marginal. It will also help attract new sources of investment.

The CfD approach requires a Government agency actively to enter into contracts, whereas other FIT models are available to all projects which meet the required criteria for payment. If the agency acts in an unpredictable way, this will discourage investors from developing projects to the point where they would be eligible for a contract. Further consultation is needed on the policy and institutional framework within which the agency will enter into contracts and on how its costs will be recovered.

None of these mechanisms removes development, construction and operational risks which are major factors associated with new nuclear, CCS, wind and biomass projects. Political risk will also remain. Returns will need to be adequate to cover these.

Government will be taking on market risk and the costs will be passed on to consumers or taxpayers. Whether the benefits to consumers from lower costs of capital outweigh the higher cost of accepting these risks is impossible to quantify at this stage. Much depends on the coherence and sustainability of the overall EMR policy package.

For CfDs, there should be different reference prices appropriate for investment in the technology in question. An annual average reference price is appropriate for plant which can schedule its own output (e.g. nuclear, CCS, biomass), but plant which cannot schedule its own output needs different conditions. Wind requires a reference price which is weighted to the timing of its output. Plant whose costs depend on fuel costs, such as coal or gas CCS projects, will need a different spread based approach.

CfDs need to be paid on a combination of energy and availability to avoid perverse bidding incentives to secure CfD income. When the market price falls below zero, payments should be on availability.

It will be important to ensure that there is sufficient liquidity around the CfD reference price. As investors trade increasingly through the market on this basis, this will attract additional liquidity.

Further consideration needs to be given to impacts on longer term liquidity and the ability of suppliers and generators to hedge their position if CfDs incentivise trading around a relatively short term reference price.

Capacity markets, as a new source of market intervention, can create significant additional uncertainty and unintended effects. Wherever possible, energy only markets should be allowed to function and capacity mechanisms should be considered only if there is clear evidence that security of supply is at risk. The consultation does not make that case convincingly.

If a capacity mechanism is introduced, the most efficient approach is to create a market for capacity where all generation (or demand side response) providing firm capacity (or an equivalent reduction in demand) is rewarded at the same value.

While both a targeted and a market-wide capacity mechanism can be designed with this principle in mind, a targeted approach is more difficult to reconcile with this approach as it only directly rewards certain plants. Unless properly implemented, a targeted approach is therefore more likely to depress prices for other plant providing capacity and to lead to their early closure. Investors could only have confidence in a targeted approach if they were convinced it would meet the conditions set out in our answer to question 22.

Under a targeted mechanism, the full cost of any capacity contracted must be reflected into the wholesale market when that plant is run and the Balancing Mechanism must allow the costs incurred in these periods, which would be very high if a large volume of capacity is contracted, to be passed through.

As a result, consumers would see very high peak and cash-out prices reflected in their tariff and contract prices as a result of the premia suppliers would charge to reflect these uncertain price effects. Government would need to be able to resist pressure to intervene to reduce these high peak wholesale prices.

The higher balancing costs would need to be reflected in the support provided for renewable generation which cannot easily balance its output.

If Government decides, on reflection, to introduce a market-wide mechanism, we would favour an approach which creates a market for capacity credits, where responsibility for delivery is distributed through an obligation on suppliers but a central body sets the required capacity margin over demand that suppliers must meet.

We do not support the introduction of an emissions performance standard which could substantially increase the risks associated with new investments. If one is introduced, we would favour a single common standard for all new plant set at an annual limit per MW of capacity equivalent to 600gCO_2/kWh for a unit operating at baseload. It should only apply to new plant and should be unchanged for its operating life.

We support the proposed principles underpinning the transition of the RO into the new arrangements. Consideration should be given to introducing a Revenue Stabilisation Mechanism for existing renewable investments to reduce wholesale price risks arising from the impact of a possible capacity mechanism.

For renewable technologies not currently grandfathered, there should be a periodic assessment of banding levels possibly aligned with the timescale for setting tariff levels for the CfD scheme.

Where the RO is vintaged on 1 April 2017, calculation of the value of a ROC should avoid complexity. Continuing to calculate headroom is a viable option but, as a new agent will need to be created to contract with developers through the proposed CfDs, this body could also be used to buy ROCs for a fixed price, and recover its costs in the same way it recovers its CfD costs.

Q1. 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?

1. The UK Government has committed to delivering greenhouse gas emission reduction targets which go beyond the requirements on the EU as a whole and a pathway to 2050 which requires decarbonisation of the power sector by the 2030s. We recognise that the Government needs to provide stronger incentives to build new low carbon capacity to meet these targets. Renewables investment is being effectively driven by the Renewables Obligation (RO), but the EU ETS is not yet providing the reliable long-term price signal which investors in the UK need to ensure that the value of other low carbon investments will be adequately rewarded. One of the main shortcomings is the lack of a credible carbon price signal for the post-2020 period. Government interventions should minimise effects on the EU internal energy market and be consistent with the EU ETS, which the Government should continue to work to improve as an investment driver.

Q2.Do you agree with the Government's assessment of the future risks to the UK's security of electricity supplies?

2. We accept there is a risk that security of electricity supplies will not remain at the level which the UK has become accustomed to in the recent past. While there is a large volume of capacity in various stages of development, the economic case for investment in new CCGT capacity or in life-extension of existing capacity is not yet clear cut, given the targeted growth in the volume of wind generation necessary to meet the requirements of the EU Renewables Directive. This, together with the volume of fossil capacity needed to maintain security of supply when wind

generation is low, will tend to create a surplus of capacity and reduce prices across the market for most of the time. Increased wind generation will also lead to lower load factors for non-renewable plant, requiring this plant to make a return from higher revenues over shorter periods. In the current market, prices would need to rise to exceedingly high levels, which might attract regulatory or political scrutiny, in order to reward peaking capacity. In addition the incidence of these prices is also difficult to predict.

3. This creates a more difficult environment in which to attract the investment needed to replace the large volume of fossil and nuclear plant closures expected over the next decade or more. However the current market will respond to anticipated capacity shortages with new investment when investors are confident that prices will rise to a level which will reward investment, with the emphasis potentially shifting from CCGT capacity to more open cycle capacity in future.

4. Whether and what type of action is required is largely a political judgement about whether the risks and cost of introducing change outweigh the risks and cost of not taking action. In reaching a judgement, Government does need to consider the impact of unexpected increases in demand or unexpected capacity availability problems, as the UK planning system is not responsive enough to permit new construction to proceed sufficiently rapidly to respond. The pre-application requirements of the Planning Act 2008 appear to have extended the overall timescales associated with new investment in technologies, such as CCGTs (or OCGTs), which have not in the past posed major planning problems.

5. There are a number of potential responses to this problem. Our preference is that, where possible, energy only markets should be allowed to function and that capacity mechanisms should be considered only if there is clear evidence that security of supply would otherwise be at risk. We have argued that the priority should be to incentivise more flexible demand side response. There will be increasing scope for demand side response as the UK transport and heat markets are electrified. The planned increased interconnection with other European countries can also help deliver the flexibility required of a system with a very large volume of intermittent wind generation. We would also favour options which supported or were consistent with a harmonised EU internal energy market, which the European Council agreed should be achieved by 2014. We discuss below the Government's views of the potential role of capacity mechanisms.

Q3. Do you agree with the Government's assessment of the pros and cons of each of the models of feed-in tariff (FIT)?

6. We agree that a FIT with CfD is in principle likely to be more effective than a PFIT in reducing the market risks associated with new low carbon investment, particularly for new nuclear power or CCS-fitted plant, given that it removes a larger proportion of the revenue risk for a large part of the operational life of the plant. The position is not so clear for new renewable investment where there is already an effective incentive mechanism in the form of the RO. However, for all technologies, a CfD based approach will probably make it easier to attract new sources of investment.

7. Energy companies will take wholesale market risk but there are a number of significant uncertainties which might lead to investors to require higher rewards if Government were to implement a PFIT based approach. In particular the Government's proposals for a capacity mechanism may affect prices in the wholesale market, or the capacity mechanism may be subject to change with consequences for market prices which are difficult to predict. Under a PFIT approach, investors would also have to factor in uncertainties about future fossil fuel prices.

8. A FIT with CfD, unlike a full FIT, does allow the plant to continue to participate in the wholesale market, although, as CfDs cover an increasing proportion of generation, there will be significant effects on how the market trades given that players will wish to hedge their position around a reference price. Whether the Government's aim of maintaining a functioning wholesale market and efficient dispatch can be achieved will depend on how this mechanism is implemented in detail. A PFIT on the other hand would have the least effect on the traded market.

9. In terms of bankability of the different mechanisms a CfD is perhaps less subject to political risk than a PFIT or full FIT, which could be changed by legislation, although that is not to say Government cannot take other action to address any perceived adverse consequences for Government as a counterparty over time, for example through fiscal measures (such as the nuclear fuel tax introduced by the German government), or by seeking to renegotiate the terms of the contract. The risk of tax measures increasing nuclear costs should be mitigated by appropriate contract provisions allowing these costs to be recovered. Other factors which might affect the longevity of a CfD might be changes in market design which affected the terms of the contract, for example the nature of the reference price.

10. A downside of the CfD approach for prospective investors is that it requires Government or a Government agency to act as a counterparty and to enter actively into contracts, whereas FITs are available to all projects which meet the required criteria for payment. If the Government agency acts in an unpredictable way, this will discourage investors from developing projects to the point where they would be eligible for a contract. It also opens the way to a policy framework where the Government is effectively dictating what projects will come forward and even where. Clarity is needed on how Government will administer CfDs as it is not covered in the consultation. These risks can be addressed through careful design of the framework and the role of the agency.

11. None of these mechanisms removes development, construction and operational risks which are major factors associated with new nuclear, CCS, wind and biomass projects. Returns still need to be adequate to cover these and to attract investment to these projects as opposed to other options available across our group.

Q4. Do you agree with the Government's preferred policy of introducing a contract for difference based feed-in tariff (FIT with CfD)?

12. Yes, but Government must work with industry and other stakeholders to ensure that CfDs are designed in a way which will ensure a functioning market and incentivise a range of technologies,

and the Government must consult further on the policy framework within which the agency will enter into contracts and recover its costs.

Q5. 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?

13. Fossil fuel and carbon price risks are factors affecting the cost of capital associated with investment in new generation, with fossil fuel price risk the more significant influence on electricity prices while coal or gas plant is at the margin for most of the time. The more such risks are transferred away the more it will reduce the cost of capital and improve financing options. The extent to which this will be achieved for individual technologies under the CfD model will depend on the choice of reference price. For example, wind generation cannot control its output, so an annual average reference price would not be effective in eliminating revenue risk (and in the case of renewables, the issue is the extent to which a CfD model transfers further risk away from the generator compared to the RO where revenue risk is already reduced through RO support).

14. Substantial development, construction and operational risks will remain, as will political or regulatory risk, the nature of which will depend on the type of investment envisaged. Exchange rate and interest rate risks are also relevant. Companies will also be looking at the returns available from investment compared to those available elsewhere in the UK and internationally.

15. Government will be taking on these risks and will be passing these on to consumers or to the taxpayer. Whether the benefits to consumers from lower costs of capital outweigh the higher cost to consumers of accepting these risks is almost impossible to quantify at this stage. Much depends on the specifics of the Government's policies and the coherence of the overall EMR policy package. If this is not seen as a credible long term basis for the UK, this will affect perceptions of the durability of individual policy measures. It also partly depends on how well Government policies are implemented. The risk of policy failure is not factored into the consultation's impact assessment.

Q6. 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?

16. The price signal incentivises the efficient, least cost dispatch of generating plant participating in the market in the short term to minimise costs to consumers, plant to be available when required to meet demand, efficient decisions regarding operation and maintenance of generating plant, and investment decisions which factor in generating costs in the longer term and market requirements for new capacity. These are major advantages of a competitive market which need to be preserved.

17. The proposed CfD model could potentially have perverse effects on the wholesale market price, particularly if it incentivises bidding behaviour which does not reflect operating costs to ensure CfD income is captured against the reference price. For example, if payment is based only on physical output and if the volume of capacity incentivised by CfDs (or by a PFIT or the RO) exceeds demand, plant will bid negative prices to avoid being called off and losing CfD income. This can be mitigated by making CfD payments on availability rather than physical output when wholesale prices fall below zero.

Q7. 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?

18. We agree there should be positive effects but we cannot comment at this stage on the specific cost of capital benefits of moving to a CfD or other FIT models. There will be more of an impact on nuclear (which has no current support mechanism) than on renewables of a CfD approach where the effect is likely to be marginal. Much will depend on the design of the CfD and specific contract terms.

Q8. 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?

19. A carefully designed CfD or full FIT approach would both help attract new investors more easily than a PFIT, but probably only in association with companies who can manage the construction and operational risk, or after construction is complete. CfDs should help support investment by enhancing the financing options available to existing investors, and help companies who wish to do so attract new partners.

Q9. 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?

20. In the case of renewable investment, we would expect all the FIT models discussed to be able to attract renewable investment from all types of generator with the capability to develop renewable technologies. As discussed, full FITs and CfDs may be able to widen the range of financing options for some technologies, although it should be recognised that the RO has already successfully attracted a wide range of new utility and financial investors for onshore and offshore wind.

21. Some companies have expressed concern at the absence of an obligation on suppliers to contract for renewable output and that this removes a route to market. However, given the low short run marginal costs of wind relative to other technologies, the expectation should be that the market will demand power from wind farms on an economically rational basis. Therefore replacing the

RO with a FIT model should not preclude an effective route to market, provided the framework is designed carefully.

22. We would also be concerned as a supplier about having to make payments above the market price as a result of any obligation to contract for renewable generation (given that this would have to have some form of penalty regime which would lead to suppliers having to pay a premium for renewable energy purchased) when the renewable generation is already supported under the terms of a CfD.

23. In the case of new nuclear, the number of players capable of this type of investment may be confined to existing nuclear operators and the strategic sites for development by 2025 have in any case already been purchased. We would expect new entrants or other players to be attracted in association with existing investors. The full FIT or CfD approach is most likely to achieve this in as far as it will offer relative security around income levels.

24. The range of investors in CCS is also perhaps narrower than in the case of renewables, but all FIT models could be capable of attracting new entrants with expertise in coal or gas-fired generation, together with companies with the necessary technological capabilities in CCS, depending on the terms offered. Any CfD approach would need to adopt a spread based approach to reflect varying fuel input costs.

25. The impact on suppliers is not explored in the consultation. If the CfD costs are recovered from suppliers, the cost recovery mechanism needs to be simple and transparent to avoid transferring market risks from upstream to downstream.

Q10. 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?

26. It will be important to ensure that there is sufficient liquidity in the wholesale market around the CfD reference price as generators will want to hedge their position around this price. As investors seek to trade increasing volumes of power through the market on this basis, this will of itself attract additional liquidity. Market liquidity more generally would also be enhanced by having a range of reference prices in play which would avoid focussing trading around a single price.

27. In addition to ensuring there is sufficient liquidity around the reference price from the point of view of the CfD holder, further consideration also needs to be given to whether there will be an impact on longer term liquidity and the ability of suppliers and generators to hedge their position if CfDs incentivise trading around a relatively short term reference price. CfDs could also have significant effects on price formation in the wholesale market and on how the market will balance when there is only a small volume of residual fossil capacity on the system. CfDs will need to be designed to minimise these effects.

28. In addition to the liquidity benefits, it is also sensible to have different reference prices appropriate for investment in the technology in question. An annual average reference price is

appropriate for plant which can schedule its own output (e.g. nuclear, CCS, biomass), as this plant will then be incentivised by the market to be available at the appropriate times within the year. Plant which cannot schedule its own output needs different conditions. In the case of wind, generation varies in response to wind speeds, which are difficult to predict the further away you move from real time. Wind generation therefore requires a reference price which is weighted to the timing of its output. We believe a basket of day ahead and within day reference prices (possibly with a day ahead/within day ratio of 60:40) would be appropriate for wind as this price would be more closely aligned to the price prevailing at the point of generation. A CfD would, however, need to incorporate an availability payment to avoid incentives to bid negative prices.

29. This relationship between revenues for wind generation and annual average power prices was recognised by Pöyry in their 2009 study on the impact of intermittency. Pöyry concluded that 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 time-weighted average (TWA) price. This arises because, during periods of high wind generation, there would be downward pressure on wholesale electricity prices, as wind displaces higher-cost generation. However, during periods of low wind generation, there would be upward pressure on wholesale electricity prices, as higher cost generation is dispatched.

30. As wind has little control over the periods in which it generates, even an index designed on a day-ahead basis could lead to wind generators not being able to secure the average price. It is important that this risk is fairly reflected in the CfD strike price. An annual average price on the other hand would be more appropriate for nuclear as, by definition, baseload plant will be able to capture a time-weighted average price.

31. Plant whose costs depend on fuel costs, such as coal or gas CCS projects, will need a different spread based approach (based on the difference between the wholesale price and the price of coal or gas-fired generation) to reflect varying fuel prices over time. However the issue for biomass is different not least because there is no robust fuel index. Therefore, as currently applied under the RO, biomass generation should be able to sign a long term CfD based on assumptions made for fuel. Investors would then consider appropriate strategies to hedge the long term fuel risk in the absence of a liquid biomass fuel index.

32. Were all CfDs to adopt the same reference price – say an annual average – the risk that generators would face in terms of their inability to secure income at or above the price, would need to be compensated for through a higher strike price, with consequent higher costs under the CfD falling to the taxpayer or to the consumer.

33. Any CfD will need to be robust to any market design changes arising from EU market integration and pursuit of the 'target model'.

Q11. Should the FIT be paid on availability or output?

34. We believe that CfDs need to be paid on a combination of energy and availability to avoid perverse bidding incentives to secure CfD income. When available generation from CfD and/or RO supported plant exceeds demand (for example on a windy summer night) the market can no longer produce a market price as generators will be incentivised to bid negative prices to secure CfD payments at the strike price. This issue can be addressed by designing CfDs to pay plant on availability rather than output when the price index falls below a specified floor (say zero). Given the difficulty in determining the extent to which wind plant which is not generating is available, further thought needs to be given to how to implement the availability principle. If the risk of negative prices materialising is unlikely to be more than a few hundred hours in the year (which would be the case in the medium term), a deeming approach may be a more cost-effective way to reward availability rather than measurement of wind conditions and available generation at each site.

Q12. 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?

35. We believe an emissions performance standard creates new risks which could substantially increase the discount rates we apply to new investments, and ultimately determine whether we proceed with an investment or not. In particular, we would need to assess whether the market will fund the investment through the price of carbon or otherwise (or if not, whether some other policy mechanism will fund the investment required), whether the technology exists or is likely to exist commercially to deliver the EPS, and whether the EPS might subsequently be tightened further. We have always emphasised that an EPS should only be introduced if provision is made to fund the required investment.

36. Our preference is for policy to incentivise new low carbon investment rather than constrain the ability to build higher emission plant. In our view, given that the proposed CfD will incentivise new low carbon investment, the proposed EPS now appears redundant. As new CCS plant will be driven by the proposed CfD, there appears to be minimal incentive to build new coal plant without CCS, which is in any event not permitted under existing consenting policy.

Q13. 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?

37. If an EPS is to be introduced, of the two options proposed, we would favour a single common standard for all new plant set at annual limit per MW of capacity equivalent to 600gCO_2/kWh for a unit operating at baseload. This annual limit would allow new plant operating at low load factors required to meet peak demand to operate without CCS, consistent with the approach taken in California where plant intended to operate at load factors below 60% is exempt from the EPS. This level would also be consistent with the requirement to demonstrate post-combustion CCS on a new, supercritical coal-fired power station, in line with Government

consent policy. This would cover the CCS demonstration programme and any other new coal-fired capacity which are proposed to develop CCS technology outside the UK programme.

38. In practice any investor will want to ensure any new coal-fired plant is fully fitted with CCS once the technology is proven, provided that the CfD terms are sufficient to reward the investment.

Q14. 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?

39. Yes. It should be aimed at new plant given that fitting CCS to existing plant is unlikely to be an economic use of shareholder, public, or customer funds, and that these plants have relatively low thermal efficiencies compared to new plants, lower load factors and shorter remaining operating lives. Without funding, a requirement to fit CCS to an existing coal or gas plant would bring about its early closure, adding to the investment requirements on the industry and potentially making these unmanageable. Existing coal-fired power stations will in any event have a progressively decreasing role as they are displaced by more efficient capacity, and incentivising new low carbon capacity to replace existing higher carbon capacity should be the main driver of decarbonisation of UK electricity generation.

40. The EPS should also be 'grandfathered' at the point of consent to ensure investors have confidence that their investments will not be subject to any unexpected costs. We believe an EPS should apply for the full operating life of the investment. For all fossil-fired plant, their level of operation and CO_2 emissions will progressively decline over time as new more efficient plant with lower marginal costs is built and pushes older plant up the 'merit order'. Nevertheless, after, say, 25 years, this plant will still have an essential role in maintaining security of supply. Imposing an EPS at this stage is not productive in environmental terms and is also likely to bring about the closure of the plant with adverse consequences for supply security, unless financial support covering the full cost of CCS retrofit is available under a CfD (which would be costly given the plant's age and low relative efficiency on the system).

Q15. 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?

41. To ensure an equitable approach if an EPS is introduced, any new investment which in effect upgrades an existing power station to create a new power station which has the operating performance of a new plant (for example in terms of thermal efficiency) should be subject to an EPS in respect of the unit which has been upgraded (not the entire power station). It should <u>not</u> be applied to investments made to extend the lives of existing plants with broadly their existing levels of operating performance or to meet new environmental requirements such as those required under the Industrial Emissions Directive.

Q16. Do you agree with the proposed review of the EPS, incorporated into the progress reports required under the Energy Act 2010?

42. Yes. The next review should be after sufficient experience has been obtained of CCS demonstration to understand the costs and commercial viability of the technology. Even then, consideration should be given to whether an EPS has any useful practical application.

Q17. How should biomass be treated for the purposes of meeting the EPS? What additional considerations should the Government take into account?

43. The use of biomass should be an option for meeting an EPS and thus CO_2 emissions from biomass combustion should not count toward the total emissions of a power station in calculating compliance with the EPS.

Q18. Do you agree the principle of exceptions to the EPS in the event of long-term or short-term energy shortfalls?

44. If a plant is subject to an EPS, other market participants need to be clear about how the EPS will be applied. Exceptions can create some risk. In the case of a short-term energy shortfall, provided an EPS is based on an annual emissions limit over a year, it seems unlikely that the plant would not be able to generate to the level required to meet peak demand, as the emissions limit could still be delivered through reducing generation at other times, unless the limit had already been reached. In these circumstances, it might be preferable to borrow emissions from the next period. Otherwise there is a risk that the operator could plan on the basis that the EPS would be lifted. In general we would not favour an exception from an EPS in the light of long term security of supply concerns as this would create uncertainty about what future new capacity requirements in fact were, as it would be unclear whether an EPS would limit available generation or not.

Q19. Do you agree with our assessment of the pros and cons of introducing a capacity mechanism?

45. The introduction of capacity mechanisms creates significant risks for market participants. They increase the complexity of the market and create an additional source of regulatory or political risk as they can be a new basis for intervention to achieve political rather than market objectives. They are also difficult to design correctly and international experience has shown that significant changes are required after first introduction, extending uncertainty for market participants. Wrongly designed, capacity mechanisms can incentivise too much or too little capacity or capacity of the wrong technology. They can also distort trade with adjacent markets which do not have comparable mechanisms in place, which may be inconsistent with EU market harmonisation.

46. Our preference is therefore that, wherever possible, energy only markets in combination with functioning balancing markets should be allowed to work and that capacity mechanisms should be considered only if there is clear evidence that security of supply is at risk. This is also a

requirement of EU Directive 2009/72/EC, Article 8(1). The consultation does not make that case convincingly and the modelling only suggests a relatively modest reduction in the level of demand unserved. Before considering capacity markets, demand-side response should be actively encouraged as should the development of energy storage technologies. New forms of electric load arising from the UK's decarbonisation strategy, for example, the use of electric vehicles, will offer larger flexibility potential than existing loads. The potential future role of additional interconnectors, particularly in a system with relatively few interconnections such as Great Britain, also needs to be fully considered as a means of meeting fluctuating demand and generation.

47. We recognise, however, that the UK Government is concerned that an energy-only market may not provide sufficient capacity to meet future electricity demand with the level of capacity margin that it is likely to be comfortable with, given the impact on the system of the volume of largely intermittent renewables sources required to meet the EU Renewables Directive and the relatively isolated nature of the UK system. This is a political judgement taking account of the risks of operating with or without additional measures to reward capacity.

48. Our views on capacity markets, if they are to be introduced, are set out in response to question 22.

Q20. Do you agree with the Government's preferred policy of introducing a capacity mechanism in addition to the improvements to the current market?

49. No but we understand the Government's reasons for proposing a capacity mechanism. It should be noted that we do not necessarily support all the 'improvements' in the current market listed in the consultation. This will depend on what options Ofgem comes forward with.

Q21. What do you think the impacts of introducing a targeted capacity mechanism will be on prices in the wholesale electricity market?

50. We assume that, under a targeted mechanism, capacity would have to be contracted for at full cost (i.e. long run marginal cost) and then reflected into the Balancing Mechanism and into cash out prices. The costs of reserve should apply only when reserve is called upon and not be smeared over long periods of time. This would allow the value of reserve to be spread across the market as a whole. This approach will lead to very high prices in the wholesale market through the Balancing Mechanism at periods of plant shortage, particularly if the cost of very large volumes of contracted capacity (such as the 5GW anticipated under the Redpoint modelling in 2030) has to be recovered through the cash-out price over short periods of time. While high peak prices would also have occurred in an energy only market, the incidence of these prices is probably more difficult to predict under a targeted mechanism, as it would be driven by the decisions and judgements of the system operator (or other organisation responsible for this task) rather than the market.

51. If incorrectly designed, there is a risk that a targeted capacity mechanism will have the effect of depressing prices in the wholesale market. This could lead to a situation where a small volume of capacity is rewarded under contracts with the system operator, but prices in the rest of the market are depressed as a result of the availability of this contracted reserve capacity, leading to the closure of uncontracted capacity and undermining existing investments including renewables covered by the RO. The system operator would then have to contract for increasing volumes of reserve plant. This would ultimately lead to a market where the majority of capacity not covered by CfDs was under contract to the system operator.

Q22. Do you agree with Government's preference for the design of a capacity mechanism?

52. We believe that the Government should adopt some key design principles in developing policy measures to incentivise capacity and security of supply before considering individual options. The most efficient approach to incentivising the provision of capacity at least cost is to create a market-based mechanism where all generation (or demand side response) providing firm capacity (or an equivalent reduction in demand) is rewarded at the same value, given that it is offering an identical product. This is consistent with the way an energy only market would function. It would therefore create a market clearing price for capacity or demand reduction, which all capacity or demand reduction would earn at that point in time.

53. Any capacity mechanism also needs to be robustly designed and stable providing reliable incentives that investors can respond to. Capacity mechanisms should therefore not be used to deliver other policy objectives, such as environmental goals which should be addressed through policies, such as the EU ETS or the Industrial Emissions Directive, appropriate to those goals. Otherwise investors will view the policy as unpredictable and will lose confidence in it as a basis for investment.

54. Both a targeted and a market-wide capacity mechanism can be designed with these principles in mind. However, it is more difficult to reward all capacity on this basis with a targeted approach as it only directly rewards certain plants. This approach is therefore more likely to depress revenues for other, uncontracted, capacity and to have the perverse effect of accelerating its closure, as described in paragraph 51 above. For the Government's proposed targeted capacity mechanism to work at all, it would have to meet a number of conditions for investors to have confidence in it. If investors believe these conditions may not be met, a targeted capacity mechanism would not be sustainable nor provide a reliable basis for investment. These conditions, which would have to be reflected in primary legislation, are as follows:

  I. The full cost of any capacity contracted under the targeted mechanism must be reflected into the wholesale market when that plant is run. This cost must include all capital costs, annual operating costs and the short-run operating costs of the capacity. If contracted capacity is available for less than this cost, average prices in the market will not be sufficient to support capital investment in other plant (either in new plant, such as CCGTs which would be preferable to OCGTs for long periods of capacity shortage (say during an anticyclone) or to keep existing plant open). There are several consequences of this approach which need to be understood:

- i. assuming that contracted plant runs for very short periods, the price charged for that plant when it does run may be extremely high and probably well over £1000/MWh at peak times;
- ii. these high peak prices will create additional price risks for suppliers which will be reflected in prices to consumers;
- iii. these high peak prices would have to be reflected directly in prices to at least some consumers if demand side response is to be incentivised. This may extend to residential consumers wishing to have tariffs more directly reflecting wholesale market prices once smart meters have been rolled out;
- iv. as these effects will be as a result of government policy, Government will need to be able to resist pressure to change policy to reduce wholesale peak prices.

II. DECC have proposed that costs would be fed into the wholesale market through the cash-out price in the Balancing Mechanism. This mechanism could be effective, but is likely to increase significantly the cost of being out of balance (as would alternative ways of feeding the price into the wholesale market) which will increase costs for plant less able to balance its position. If this approach is adopted, Government will need to ensure that action cannot be taken to alter the Balancing and Settlement Code subsequently to prevent the costs arising from a targeted mechanism being reflected in the cash out price.

III. Renewable generators will need to be compensated for or protected against higher balancing costs through the RO or the CfD. Renewable generation whose output is less easy to predict (particularly wind generation) gives rise to higher balancing costs. While fuller pass through of these costs to the generation giving rise to them would be more cost-reflective, and would incentivise these generators to improve their forecasting ability, these balancing costs had not been planned for at the point of investment. Existing operators of intermittent renewable plant covered by the RO will therefore need to be protected against or compensated for these costs. We propose measures to address this in answers to questions 35 and 38 below. For new renewable plant covered by CfDs, contracts will need to provide revenue security against imbalance cost as well as or as part of energy price risk. There may be similar, though potentially smaller, effects on the economics of nuclear generation which, although generally very predictable, requires a higher level of reserve plant to be available to generate should a single nuclear unit become unavailable at very short notice.

IV. The targeted mechanism should have the objective of providing additional incentives for generators to make capacity available at least additional cost to consumers and the system operator (or other agent) should be incentivised to deliver that. It should therefore not discriminate between existing and new plant, nor should it discriminate between technologies. However, it would be legitimate to tender for capacity over different time frames and long term contracts should be offered for requirements for new capacity or life extension of existing capacity covering extended time periods. It should also not be designed to deliver other unrelated policy objectives as described above.

V. The methodology the system operator or other agency uses for contracting for new capacity needs to be transparent and entirely predictable, with any changes required over time consulted on well in advance. If it is apparent that the approach varies from year to year, or is subject to political interference, investors will rapidly lose confidence.

VI. The entity contracting for capacity under the targeted mechanism needs to be independent of other commercial activities and of political influence, and if undertaken by NGC as the system operator, it should be entirely ring fenced from its other operations.

55. A number of market-wide mechanisms exist in markets outside the UK which meet the principles we have set out above. The analysis we have undertaken suggests that a system of capacity credits is the mechanism which is most market-based and would involve least disruption to the existing UK market structure. This would require an obligation to be placed on suppliers to contract for a specified volume of capacity in excess of their forecast demand, with a penalty payment for non-compliance varying with the level of under-delivery. Capacity and demand side response meeting certain criteria, but of any technology type, would be awarded a credit. This would create a market in capacity with prices varying in relation to the level of capacity available to meet demand. Investors would respond to the price signals provided by both the energy and capacity markets.

56. While we recognise the Government's concern that capacity might be over-rewarded both in the energy and the capacity market, we would expect total rewards to normalise as any excess capacity would lead to a zero value for capacity credits.

57. Capacity market design involving any form of contracting for new plant (for example through forward auctions) to meet future capacity shortages would need to take account of the timescales required to deliver projects from the award of a contract. Unless projects have already entered the planning process, the timescale from initiation of a project to commissioning could be of the order of eight years for CCGT capacity taking account of the pre-application requirements of the Planning Act 2008 which require developers to carry out much more front-end engineering work. This may require the system operator to forecast capacity requirements on comparable timescales, which will involve major forecasting uncertainties. Whether developers will seek planning consent for projects in anticipation of being awarded a contract in future will depend on the costs involved and the probability of successfully securing a contract. As a minimum the basis on which capacity will be sought needs to be robust and highly predictable.

58. There needs to be further consultation with market participants and with network operators on the design and operation of capacity mechanisms, given that the Government's policy work in this area is not yet fully developed.

Q23. 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?

59. Demand side response and storage should be eligible under a capacity mechanism but any demand side solutions which are paid a capacity payment must be able to demonstrate that they can genuinely provide value and that the contracted capacity can be delivered when required. If the costs associated with a targeted mechanism are not reflected in the wholesale market through the Balancing Mechanism, as discussed above, reduced prices and volatility in the energy market will reduce incentives for demand side response.

60. This particularly applies to demand side response that the system operator may not be able to take into account as part of a capacity mechanism. For example solutions which rely on shifting consumption over time in order to reduce energy bills for customers by enabling their load to follow volatile prices would suffer if capacity markets led to reduced peak energy prices. Such systems, e.g. intelligent charging mechanisms for electric vehicles or heating solutions, may provide load-shifting on a relatively passive basis that is not directly controllable by the system operator. The extra capacity created by such solutions would be of less immediate value than conventional "firm" capacity, even if the long-term effect (on peak demand) would be similar.

61. A highly interconnected European market would enhance the ability of national markets to benefit from installed capacity in other markets across Europe. Coordinated markets functioning together with enough cross-border capacity should allow the systems to assess and address their capacity needs in a coordinated manner. However, the introduction of national capacity mechanisms will tend to distort trade between markets and investment signals for new interconnections.

62. While in theory it could be argued that capacity made available through interconnectors with other systems should be eligible under a targeted mechanism, in practice this does not seem practical. There would, for example, be difficulties in assessing its actual contribution to UK demand as opposed to demand in the country in which it is located or its contribution if the capacity is called for when the interconnector is already fully importing to the UK. It would also be necessary to avoid over-rewarding the capacity in both markets.

Q24. Which of the two models of targeted capacity mechanism would you prefer to see implemented:

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

63. If a targeted mechanism is introduced, either approach would require the full cost paid out as a capacity payment to be reflected into the wholesale market (whether via the cash out price or another mechanism). Economic dispatch is the more market-based approach and more likely to contribute to lower overall costs. A last-resort approach might also be difficult to sustain if the system operator is holding a large volume of capacity in reserve as there will be pressure to allow this plant to run more frequently, if other capacity has higher costs.

Q25. Do you think there should be a locational element to capacity pricing?

64. If a targeted model is introduced, we assume that the system operator would not contract for capacity that could not contribute to meeting peak demand because of transmission constraints. In a market-wide model, we would not exclude capacity from the model on locational grounds (given that locational signals already exist through TUoS charges), although its value in terms of contributing to meeting demand would have to depend on its ability to provide power when and where required.

Q26. 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?

65. We see the CfD as the primary policy mechanism incentivising new low carbon investment (although much more work is required on how it will be implemented and how its costs will be recovered) but question the usefulness of carbon price support and the emissions performance standard, which are not essential parts of the package and appear driven by mainly political considerations. A CfD could simply operate on the basis of the carbon price signal provided by the EU ETS, which would avoid its adverse impacts on UK competitiveness and consumer prices, and reduce the overall cost of investment to consumers, where the CPS imposes additional costs above the ETS price. We do not favour the introduction of capacity mechanisms but, if one is introduced, it must meet certain principles (see para 54). A targeted approach will only work if investors are confident that certain conditions can be met.

Q27. What are your views on the alternative package that Government has described?

66. See our answer to question 26. A PFIT would create more of a role for the wholesale price which would be a more important driver of income than under a CfD model. In these circumstances, impacts of other policies on the wholesale price will be key. The CPS would have a more significant role as it would be intended to provide more certainty about the carbon element of the wholesale price. However, fossil fuel price (via its impact on the wholesale price) would remain a much more significant risk to low carbon investment. We also doubt that investors would attach much certainty to the level of carbon price support (CPS) over the timescales they are looking to make a return on their investments. The impact of capacity mechanisms on the wholesale price would also be an issue.

Q28. 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?

67. The impact of a CfD based approach on the retail market has not been explored and further detail is needed on how the purchasing agency will recover costs. As the volume of CfD supported generation grows, this may have a significant effect on supplier costs, with a larger proportion of cost determined by CfD payments. Predicting the incidence of these payments may become an issue.

68. There are also important interactions between capacity markets, the retail market and the role of demand side response facilitated by smart metering. This in turn may have impacts on DNOs introducing smart grid technology to incentivise demand response and changes in levels of distributed generation to reduce the need for grid reinforcement to accommodate the electrification of heat and transport. DNOs need to be fully involved in further work on capacity markets progresses.

69. The package will also have a range of significant impacts on other European markets which need to be further considered. The Government should consider the impact of the Commission's preferred 'target model' on the EMR package.

Q29. How do you see the different elements of the preferred package interacting? Are these interactions different for other packages?

70. Much depends on how the elements of the package are implemented in practice. The main interaction is between the CfD and the capacity mechanism. One issue is the relationship between the FIT/CfD and the capacity mechanism. Under a market wide mechanism, some CfD supported plant would also be eligible for capacity payments and this would need to be reflected in the level of CfD support it received. The impact of a targeted mechanism on balancing costs could be significant and the consequent effect on the economics of wind generation would need to be considered in assessing required CfD support.

71. If a PFIT were to be chosen rather than a CfD, then any change to or uncertainty in wholesale prices as a result of the implementation of a capacity mechanism would be likely to act as a deterrent to investment until the full impacts of that mechanism were understood.

72. The CPS will have some relationship with capacity mechanisms as it will affect the profitability of different plants, although this will depend on the level set and the extent to which its future level can be relied on for investment purposes. In general it will reduce the profitability of existing higher carbon coal plant and improve that of lower carbon gas plant, although this effect will diminish significantly as coal-fired plant is withdrawn from the system.

Q30. 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?

73. Aside from our concerns about carbon price support described in our response to that consultation, we are concerned that:

- the proposed FIT/CfD approach is a more directional approach by Government in the market. Whether new low carbon investments go ahead or not may depend rather more on the Government's willingness as a counterparty to sign contracts compared to current policies where investors come forward with investments in response to incentives such as the RO. This has the potential to create instability and uncertainty for investors. How much risk will exist under the new proposals will depend on how Government implements the new framework in practice, the extent to which it acts consistently with its energy policy objectives including the national policy statements, and the degree of consensus between the political parties over time. This consensus will be helped if customers understand how additional costs are arising and what their purpose is in terms of delivering secure and low carbon energy supplies;

- the capacity mechanism may have unintended and adverse consequences on the energy market, exacerbating the security of supply problem. We have described this issue and potential solutions in response to question 22 above;

- it will take longer to determine detailed policy requirements and implement these policies correctly than the Government anticipates, given constraints on Parliamentary time, the need to secure clearance for the preferred CfD policy under EU state aid rules and the industry's concerns about the Government's proposed approach to capacity markets. This enduring policy uncertainty may inhibit the investment in new generating capacity required to maintain security of supply from 2015. The Government therefore needs to clarify its policy intentions as soon as it can and then implement reform rapidly, while in parallel engaging fully with the industry on detailed implementation. It also needs to create the institutions, if initially in shadow form, to support the policy framework as soon as practical, once the required market reforms have been determined.

Q31. 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?**

74. While we see theoretical attractions, there are a number of practical problems with an auction based approach to setting price levels, particularly when applied to major low carbon power projects such as new nuclear, offshore wind and CCS based fossil projects:

    - Sunk costs incurred prior to auction stage. Companies will not be in a position to bid realistic costs in an auction until they have secured development consent and know the conditions attached to the consent, and sought tenders from plant manufacturers. In the case of nuclear, developers also need to understand the cost implications of compliance with the site licence. These all incur substantial costs. The risk of failing to secure the required revenue levels following an auction may well dissuade developers from committing the expenditure required to develop the project to the point where it can make a bid, particularly if there are similar investment options available elsewhere, e.g. in other jurisdictions which do not have these risks.
    - Cost uncertainty at the auction stage. If auctions are carried out at an earlier stage in the process, developers will look either to factor project risk into their bids or will require the agreed contract terms to be reopened once the true costs are known. Either way, this creates significant risk for the Government in terms of effective price discovery. In the former instance the revenue level may in fact prove to be too high. In the latter, the renegotiation of the bid may invalidate the original tender process as the bidder may not in the event be the lowest cost. If the auction is carried out before development consent is obtained, there is also the risk that the winning bidder may not secure planning approval and that the established revenue level is not high enough to incentivise the remaining projects, in which case the auction would have to be repeated.
    - Project development differences. At the time of an auction, projects are likely to be at different stages of development which will make it difficult for Government to compare bids on a fair and consistent basis. Equally, developers at a less advanced stage may be at a disadvantage because they have to factor in more project or market risk.
    - Effectiveness in price discovery. There may be a limited number of bidders, particularly for new nuclear and offshore wind projects, because of the limited number of potential investors and the restricted availability of sites, as well as for fossil and CCS projects, which are at an early stage of development of the technology. As with any market-based process, auctions with, say, only two or three participants do not lend themselves to competitive price discovery. The Government may also want a large proportion of projects to go ahead on security of supply and carbon reduction grounds or the project in question may have high political significance in terms of delivery of the Government's policy goals. This may put the Government at a disadvantage in any auction process. Overall these concerns would be likely to lead Government to scrutinise cost bid in auctions in detail, which would seem to defeat the purpose of a competitive rather than an administered approach. Furthermore, where a

company has already secured ownership of a site (nuclear) or other rights (Round 3 Wind), Government would need to consider the implications of failure to win an auction for that particular resource. Even if there were a mechanism to make available the site to an alternative future bidder, this could lead to substantial delay in developing a prime site.

75. An alternative is to look at the costs and revenues of eligible technologies to help determine the revenue levels these might require going forward. This is the approach that has been adopted in relation to both the RO and existing FIT regime (for schemes below 5MW). While this also raises a number of issues, we believe these can be more easily addressed.

76. We believe developers will have more confidence in a process where either:

- the potential revenue level is known well in advance and investors can seek to develop a project which meets those criteria. This may be appropriate where the Government is concerned to impose a cost ceiling, wants to develop the lowest cost technologies and is less concerned about delivering a defined target or supporting multiple technologies (as might apply if the carbon price was the only driver and was the case when there was a single RO band), or
- investors can develop projects against a presumption that Government will want a substantial number of projects to proceed to deliver a defined objective, provided developers are not making excessive returns. This would appear to us to be the situation in the case of offshore wind, given the UK renewable energy strategy and the Round 3 tenders, and that of nuclear, where Government has indicated that it believes nuclear is economic and has designated specific sites for development by 2025. In these cases companies could offer DECC a relatively open book approach to project costs and forecast market assumptions, which would enable Government to satisfy itself that levels of return were reasonable. This is similar to the approach adopted for RO banding and would enable revenue levels to be set at a value which had a reasonable prospect of attracting a sufficient level of investment.

77. In any case success in securing a contract and certainty about price levels will be required before making the final investment decision for a project, which in the case of new nuclear will be some 7 years before commissioning.

78. We would expect CfDs to support a number of different technologies with different strike prices reflecting the costs of each technology, and reference prices appropriate for the technology in question. We cover this in more detail in response to question 10. In principle we would envisage CfDs operating in a similar way to other FITs, with a set price available for a defined period of time, after which the support level is reviewed, although some contract terms could perhaps be varied within a predefined range to respond to the preferences of individual investors. Investors would respond to this strike price to discover the lowest cost projects. How contracts are entered into needs further discussion.

Q32. What changes do you think would be necessary to the institutional arrangements in the electricity sector to support these market reforms?

79. Under a CfD based approach, a counterparty to contracts will be required together with a mechanism for recovering costs. This will need to be Government backed and a view will need to be reached on the policy framework within which it will operate, the extent to which it has freedom to contract, and against what criteria.

80. An entity will also be required to determine requirements under a targeted capacity mechanism. This could either be left to the system operator, in which case it would need to be entirely ring-fenced from NGC's commercial operations, or capacity requirements could be set by an independent agency. The capacity mechanism would need to be administered by an entity independent of Government to reduce the risk of political intervention but operating within clearly defined rules.

Q33. Do you have view on how market distortion and any other unintended consequences of a FIT or a targeted capacity mechanism can be minimised?

81. See the answers to the questions discussing these proposals above.

Q34. Do you agree with the Government's assessment of the risks of delays to planned investments while the preferred package is implemented?

82. Yes.

Q35. 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?

83. We support the proposed principles underpinning the transition of the RO into the new arrangements. In particular, we welcome the acceleration of the banding review, introduction of a new support mechanism preferably in 2013 and maintenance of support for projects under the RO until 2037. We also believe that to provide confidence to investors, they should be able to select either the RO or the new support mechanism between 1 April 2013 and 31 March 2017. If a CfD is introduced for new low carbon investments, we believe that consideration should also be given to introducing a Revenue Stabilisation Mechanism, effectively a CfD around the power price for existing investments. This would help provide more confidence to investors in the light of the potential impact that a capacity mechanism may have on power prices and the medium term risks of negative prices that RO wind projects will continue to face as the UK electricity sector continues on its path to decarbonisation by the 2030s.

84. To help reassure developers, it would be helpful if these proposals were incorporated in the forthcoming White Paper. This should include the proposal to allow existing and new eligible projects covered by the RO a one-off choice to opt into a Revenue Stabilisation Mechanism.

Q36. 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.**

85. As we indicated above, we believe investors would welcome the choice between accrediting projects under the RO or a new low carbon mechanism. However, for offshore wind and biomass, where there are typically construction programmes lasting three years or more, there is in effect little or no choice. In reality these projects will only have the option of accrediting under a new low carbon support mechanism. It is therefore essential that the new regime is introduced as soon as is feasible to provide clarity to companies who will be required to make decisions on substantial investment propositions for large scale renewable projects. Without this clarity, investments will be delayed, making it increasingly unlikely that the UK will be able to achieve its renewable energy targets.

Q37. 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?**

86. For the technologies not currently grandfathered, we believe the best approach would be to carry out a periodic cost assessment that could be aligned with the timescale for re-setting tariff levels for the new CfD scheme. However, as with the current approach, where it is clear that costs are significantly different from those assumed, it should be possible for an early review to be conducted, as occurred with offshore wind in 2009.

Q38. 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**

87. When the RO is vintaged on 1 April 2017, we believe calculation of the value of a Renewable Obligation Certificate (ROC) should be on a simple, easily understandable, basis, and we agree that continuing to use both the target and headroom is inconsistent with this approach. Continuing to calculate headroom is a viable option. However, as a new agent will need to be

created for implementing the new CfD scheme, this body could also be used initially to buy the ROCs for a fixed price, and recover its costs in the same way it recovers its CfD costs. We believe this best meets the principle of simplicity, avoids having to make annual forecasts of production from RO eligible plant, and potentially provides a mechanism for reflecting any increased risk for wind resulting from the reform proposals, especially around the introduction of a capacity payment, through the fixing of the value of a ROC.

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