centrica

# Consultation on Electricity Market Reform

## Centrica Response

### Executive Summary

**Overview**

- We welcome and support the Government's recognition that the electricity market needs to be reformed in order to deliver decarbonisation and security of supply objectives.
- We believe it is essential that any reforms consider the overall impact on costs to customers, both households and businesses. We believe the competitive market delivers real benefits to customers and support retaining its principles where possible.
- Government has a short window of opportunity to reform the current arrangements and influence investment decisions. It is essential that the Government follow this consultation with a White Paper this spring and legislation swiftly afterwards, that can be passed in 2012.
- Government must also remain focused on addressing other issues that impact on investment coming forward such as planning and transmission access.
- It is important that the Government provide clarity about transitional arrangements for the Renewables Obligation, including grandfathering support for existing investments, to avoid an investment hiatus.
- We have responded separately to the Treasury consultation on Carbon Price Support, which we think is an essential component of the EMR Package.

**Contracts for Difference (CFD) & Premium Feed-in Tariffs (PFIT)**

- In principle we believe the PFIT is closer to maintaining the competitive market landscape, which we believe has delivered real benefits to customers. It is therefore more consistent with our preference for maintaining a pro-market approach more generally.
- However, a PFIT can only work if investors feel comfortable that the revenue support it delivers is commensurate with the risks associated with their investments, including wholesale price risk. Agreement between industry and Government on wholesale price forecasts is therefore an important element for establishing a PFIT.
- If the above cannot be achieved, a CfD may become a more pragmatic solution as it reduces the parameters for necessary agreement.
- However, it is likely that implementation of CfDs will be a lengthy process. It will require establishing the necessary institutional and legislation arrangement and for the Government and industry to strike an agreement on all key contractual issues of CfDs.
- We believe both a PFIT and a CfD are workable concepts. There are important design and implementation details associated with both, and until these are better clarified and understood, we cannot conclusively support one over the other. However, we have not identified any insurmountable obstacles when we have considered detailed design issues.
- In terms of setting the price, whilst auctioning is more theoretically appealing, in practice we believe an administered approach is more appropriate given the limited number of bidders and the heterogeneous nature of the projects. We support the precedent set by the RO banding review in which Government sets a support level, following consultation, which all qualifying projects can aim for.

**Emissions Performance Standards (EPS)**

- If the EMR package is implemented effectively, there is no need for an EPS.
- However, we believe the proposals in the consultation are workable as long as the EPS limits do not prevent the construction of new gas fired generation, necessary for security of supply.

**Capacity Mechanisms**

- The UK market has historically performed well in delivering secure electricity supplies. However, we cannot be certain that sufficient capacity will be maintained on the UK system given the scale of regulatory uncertainty currently affecting the market.
- In addition, we believe there are system reliability issues as a consequence of the planned build of large amounts of intermittent generation.
- We feel that the consultation insufficiently distinguishes between the related but distinct issues of supply adequacy and system reliability.
- We believe that both issues can be addressed through a market-based approach: implementing a reserve market including a 'three year ahead' auction for reserve capacity, in which all options including existing plant, prospective plant, demand side response can participate; the price paid for their capacity will reflect the actual market need at that time.

**Alternatives to the EMR package**

- The EMR package is likely to deliver the Government's goals of security of supply and decarbonisation.
- However, implementation of the EMR package would create a complex electricity market with a high degree of Government intervention.
- We believe that a simpler, more market-based alternative should also be considered.
- Such an alternative is the introduction of a 'Portfolio Carbon Standard' that places an obligation on suppliers to sell electricity with a capped carbon intensity. This creates a premium market for low carbon electricity.
- Aside from the simplicity, the key advantages of this approach are that:
    - Government does not have to 'pick winners' in terms of technology
    - It is a lower cost-alternative, relative to achieving decarbonisation goals solely through the carbon price.

## 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?***

- Yes. We agree that the current market structure is unlikely to deliver the level of investment in low carbon generation required to meet the UK's carbon reduction targets.
- The electricity market in the UK has delivered a secure supply of power to Britain's homes and businesses over the past decades.
- However, there are challenges ahead in order to meet the UK's low carbon targets and associated decarbonisation of the power sector, and to continue to ensure security of supply, particularly in the context of greater intermittent wind.
- Meeting these challenges will require significant investment over the next decade and beyond, with Ofgem putting the number at around £200bn required by 2020.
- A balanced power generation technology mix is needed to ensure a diverse and secure electricity system. This is likely to include a range of renewable technologies, flexible back-up capacity to wind (which generates power intermittently), new low carbon firm generation including nuclear and, if the technology can be proven, carbon capture and storage (CCS).
- Current market arrangements are not designed to meet the multiple goals of security of supply, decarbonisation and promoting renewables, all at least cost.
- The EMR package should bring clarity to the future set up of the electricity market, building investor confidence and opening the door to billions of pounds of investment into the UK market, including an expected £15billion investment by Centrica by 2020.
- Government has a short window of opportunity to reform these arrangements and influence investment decisions. We broadly support the EMR package, but also believe that it is worth continuing to explore more market based alternatives in parallel to the EMR package.
- Such an alternative is the introduction of a 'Portfolio Carbon Standard' that places an obligation on suppliers to sell electricity with a capped carbon intensity. This creates a premium market for low carbon electricity.
- Aside from the simplicity, the key advantages of this approach are that:
    - Government does not have to 'pick winners' in terms of technology
    - It is a lower cost-alternative, relative to achieving decarbonisation goals solely through the carbon price.
- More detail can be found in the annex to our response.

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

- Yes. We agree that new generation investment will be needed as some of the existing capacity retires. This is likely to be a combination of CCGTs and renewables and new nuclear, and in addition some CCS depending on whether the technology can be proven.
- We support the Government's analysis that there could be an issue with security of supply, both in terms of supply adequacy and supply reliability (i.e. sufficient flexible plants to cover intermittent generation).
- The current high level of policy and regulatory uncertainty, is likely to undermine the market's historic ability to deliver capacity adequacy going forward. For

example, one danger that might affect a view on regulatory uncertainty is whether or not policy targets are achieved.
- A scenario could be envisaged around the middle of decade when the likelihood of a looming 'crunch' could be significantly higher than today. A rapid build-up of required new capacity may be constrained by planning and consenting constraints.
- As more inflexible (nuclear) and intermittent (wind) generation enters the system towards the end of this decade, we also believe there is a supply reliability issue. In order to deliver the flexibility needed, support will be needed for options that deliver that flexibility such as existing CCGT and potentially new peaking units and enhanced demand side response.

## Options for Decarbonisation

*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 broadly agree with the Government's assessment; however,
- Although removal of wholesale price risk through a CfD is likely to result in a greater reduction in the cost of capital than under a PFIT, we believe the impact is overstated and the actual reduction in risk will be largely determined by the level of confidence in the institutional arrangements and governance, and the detail contractual terms (such as length of contract and whether contracts will be forcibly renegotiated if CfDs become significantly economically favourable for the generator)
- A lower cost of capital should provide a greater degree of confidence that customer bills will be lower than they otherwise would have been. However, if wholesale power prices turned out to be lower than anticipated then a PFIT structure would be better for customers than a CfD.
- The certainty of achieving low carbon targets could be managed with either CfD or PFIT and is dependent on a range of factors such as the level of premium or the CFD strikeprice.
- For intermittent generators, the extent to which power price risk is removed through the CfD depends on making the correct selection of indexation arrangements as we note below in our response to Q4.
- In addition to the proposed models of feed-in tariff, we have also explored a more market based solution: a Portfolio Carbon Standard. This places an obligation on suppliers to sell electricity with a capped carbon intensity. This creates a premium market for low carbon electricity.
- Aside from the simplicity, the key advantages of this approach are that:
    - Government does not have to 'pick winners' in terms of technology
    - It is a lower cost-alternative, relative to achieving decarbonisation goals solely through the carbon price.
- More detail can be found in the annex to our response.

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

- In principle we believe the PFIT is closer to maintaining the competitive market landscape, which has historically, and will continue to benefit customers. It is therefore more consistent with our preference for maintaining a pro-market approach more generally.

- However, a PFIT can only work if investors are comfortable that the revenue support it delivers is commensurate with the risks associated with their investments, including wholesale price risk. Agreement between industry and Government on wholesale price forecasts is therefore an important element for establishing a PFIT.
- If the above cannot be achieved, a CfD may become a more pragmatic solution as it removes this potential sticking point and reduces the scope for necessary agreement to one of capital costs, rates of return, risks and contingencies. On the other hand, it is likely that implementation of CfDs will be a lengthy process. It will require establishing the necessary institutional and legislation arrangement and for the government and industry to strike an agreement on all key contractual issues of CfDs.
- We believe both a PFIT and a CfD are workable concepts. There are important design and implementation details associated with both, and until these are better clarified and understood, we cannot conclusively support one over the other. However, we have not identified any insurmountable obstacles when we have considered detailed design issues.

***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?***

- The working assumption has been that risk will not be transferred from to the Government but to the customer.
- We concur with the analysis that in general low carbon generators tend to have high upfront capital costs, lower and more stable operating costs, and do not have input cost exposure to fossil fuels or carbon (with the exception of biomass and coal/gas & CCS). Thus a fixed price arrangement between such generators and customers who want price stability (via the Government) generally reduces risk.
- In theory this leads to a lower cost of capital which should in turn provide a greater degree of confidence that customer bills will be lower than they would otherwise have been. However we believe the scale of reduction in cost of capital is overstated.
- As pointed out in our response to Q3 above, delivery of lower risk and cost of capital with CfD will depend on institutional arrangements and governance. Questions on indexation, length of CfD contracts and confidence in the robustness of such contracts are key issues. If the clauses of contracts, or the governance put in place, are not perceived to provide sufficient protection or revenue certainty to generators, this could result in a higher cost of capital. It is important to note that the industry and financiers have generally taken market price risk, and are comfortable doing so in a stable and transparent market framework. The commercial implication of removing market price risk and replacing it with regulatory risk is less straight forward if there is considerable uncertainty in regulatory regime.
- There is a risk that the market as currently designed would cease to provide adequate levels of returns to wind generators as a result of cannibalisation risk (the inverse correlation between power prices and wind generation that will develop as the proportion of wind generation grows). Removing the long-term electricity price risk could enable the reduction of this cannibalisation risk.

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

- We believe that it is important that all generation is exposed to, and responds sensibly to, fluctuations in market prices. Equally important is to note that the market price signal also serves as an important instrument and incentive for demand-side participation. Real time price signals also have an important role to play in the Government's wider development plans, such as smart metering and smart grid, which relies on a market that allows real-time response.
- For this reason, we believe it is important that all support payments are made on available capacity rather than output so as to avoid "negative bidding behaviour" (i.e. generators offering to sell energy at a loss in order to keep generating so as to receive their low carbon support payment).
- All generation will also have an incentive to maximise output during periods of high price, either to capture additional revenue or to avoid high penalties from imbalance cashout should they become unavailable.
- We do not believe that the timing of scheduled maintenance outages for some low carbon generation because of the many other technical and practical constraints on these planned outages such as the need to procure equipment. Unless the planning horizon for maintenance is less than the time period covered by the indexation arrangements, generators will have to make informed guesses when low price periods may occur. In the future, these may be associated as much with periods of high wind generation as low demand and will thus be difficult to predict.

***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?***

- The removal of wholesale price risk through a CfD results in a theoretical reduction in the cost of capital relative to a PFIT. The perceived reduction in risk is, however, largely determined by the level of confidence in the stability of the regulatory regime (see answer to Q3 and Q5 above).
    - Delivery of lower risk and cost of capital with CfD will depend on regulatory risk, institutional arrangements and governance. If the clauses of contracts, or the governance put in place, are not perceived to provide sufficient protection or revenue certainty to generators, this could result in a higher cost of capital. It is important to note that the industry and financiers have generally taken market price risk, and are comfortable doing so in a stable and transparent market framework. The commercial implication of removing market price risk and replacing it with regulatory risk is less straight forward if there is considerable uncertainty in regulatory regime.
- Our analysis shows that the impact on cost of capital for new build nuclear projects of power price risk is less than construction risk and of broadly the same magnitude as operational risk.
- For most large-scale low carbon projects, the impact on cost of capital from power price risk is far less than construction risk and, in certain cases, also technology risk.
- There are other major source of risk that impinge on new projects prior to FID such as planning policy and transmission access policy that equally have to be resolved before investments can take place.

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

- Whilst pre-construction project finance is possible for some renewable projects, it is likely that other low carbon investments such as nuclear will have to be financed on balance sheet.
- Some investors may find a CFD type structure without wholesale power price exposure more attractive / less risky, however we believe that a major barrier to attracting finance for low carbon generation is the willingness of finance providers to take construction risk. Thus we would expect any financing to be post-construction.
- The ability to attract finance is a function not only of the project itself but also the equity sponsors supporting such projects, with lenders charging significant premium or deciding not to provide debt finance at all to weak sponsors. This will clearly have an immediate impact on the sponsors' cost of capital.
- In addition, the way that rating agencies are now treat non-recourse project finance debt has the effect of adding it back onto corporate balance sheets which removes much of the attraction of this form of financing. This limits the large utilities' ability to refinance projects and recycle capital into new investments, thus reducing the overall level of capital available for investment.
- Ultimately, the level of finance that flows will depend on whether all the investors (including equity sponsors, lenders and, if applicable, PPA offtakers) feel comfortable that the returns they derive from such projects, including the revenue support the projects are receiving, are commensurate with the associated risks.
- EMR needs to be seen within the context of a range of other risk factors that impact on the scale of finance that is likely to flow such as the need for a supportive political climate for investment, an effective planning regime and appropriate transmission access.

***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?***

- It is difficult to generalise by type of generator; the relative attractiveness of the different FIT models will depend on many factors relating to size of organisation, capital constraints, internal capabilities (technical, operational, trading etc), experience in the power sector in the UK and overseas and general risk appetite.
- There will also be organisations who will be looking at a range of investment opportunities in UK in comparison to opportunities elsewhere in Europe or globally
- Regarding the impact on relationships with energy suppliers, as with all commercial organisations, suppliers will in general undertake activities that they believe will be profitable and value enhancing. They should not be treated as one entity, they all compete with each other and act completely independently.
- We do not share the concern of some independent generators that the removal of the 'Obligation' element as with the RO will mean independent generators will have greater difficulty entering into PPAs with suppliers. The current RO does not oblige suppliers to buy ROCs nor enter into PPAs with renewable generators.

***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?***

- Additional measures to improve liquidity within the current market arrangements are being considered separately by DECC and Ofgem outside the EMR consultation and are not addressed here.
- We believe that the design of the CFD indexation arrangements will determine the impact of this contract form on market liquidity.
- We note however that any impact will be small prior to 2020 due to the limited volume of electricity that will be covered by these arrangements by that time.
- Generators covered with CfDs will have a natural desire to sell out their expected production into the relevant index as it "prices in". In this way they will ensure that the price they receive for the power is the index price and that they therefore receive the full strike price when the difference payment is made. If suppliers' exposure to the buy side of the CfDs is properly structured then this would also facilitate creating a demand for the same indexation which would be beneficial.
- We believe that the indexation needs to take account of specific characteristics of certain technologies i.e. intermittent generation needs prompt indexation but reliable predictable generation is indifferent to which index is used. There seems no reason why the index for all CfDs needs to be the same.
- We recommend that <u>wind and similar intermittent generation</u> use a day ahead index ( based on traded data, such as the LIBA index or N2X index).
    - o Day ahead wind generation forecasts are fairly accurate, but this accuracy falls rapidly going further into the future. Thus a day ahead index would allow wind generators to sell their production into the index with reasonable accuracy.
    - o We do not believe that half-hourly indexation for wind generation is necessary or even practical. It would create significant process issues, if large volumes of power were only traded very close to gate closure, and would create unnecessary risks for suppliers if they tried to leave positions open that close to gate closure. It would be particularly difficult for generators with no or limited trading capabilities.
    - o A month ahead index would be very difficult for a wind generator to manage. They would have no reliable forecast of generation volume so they would not be able to forward sell to hedge their index exposure. They would have to run unhedged and accept the risk that the price they received from prompt sales would not match the price derived from the index. This would effectively leave the generator with significant cannibalisation risk that the achieved power sales price will be less than the average market price (due to the inverse relationship between power prices and high wind periods).
    - o The generator could seek to mitigate this to some extent through seeking a higher strike price, but there is considerable risk that they would misestimate this risk.
- In order to promote liquidity further over periods further ahead, <u>reliable generation such as nuclear</u> could use month ahead, quarter ahead, season ahead or year ahead, or some basket of all or some of these. In each case the baseload price would seem the best price to use.
- We believe that supplier interest in these CfDs would be stimulated if the costs of the CfD are passed through to suppliers in proportion to their sales rather than the CfD costs being funded by central Government from general taxation revenue. In the former, the combination of buying a proportionate element of power on the same index basis as a CFD together provided the respective share

of funding to underpin CFD would result in suppliers effectively hedging a proportion of the power requirements at a known price. This would reduce price volatility for suppliers, and in turn customers.

Under a Premium FIT, there would be no direct impact on wholesale market liquidity since the generator still fully participates in the forward and balancing markets.

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

- We believe there are good reasons to pay on availability, modified in the case of intermittent generation, to take account of what generation is possible.
- For most occasions, availability would be equal to actual output unless the generation had been constrained down for system balancing reasons or the spot price was less than the short run marginal cost of that generator.
- If payment were to be based on output as with the current RO then in a situation of surplus generation there would continue to be an incentive to generate irrespective of the market price. In extreme, this would lead to competition between generators that are receiving support who will be incentivised to avoid being turned down which could result in such players offering negative bids to sell energy at a loss.
- We believe payment on availability is practicable and would minimise the incentive for generators to bid negative prices into the system, which would be disruptive to the market.
- The principle should be that low carbon generators should respond in a rational economic way to spot price signals but should not be disadvantaged in terms of support payments if the correct behaviour is to turn down or off.

## Emissions Performance Standards

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

- If a carbon floor and low carbon generation support mechanism are implemented correctly, there is no need for an EPS.
- We support DECC's proposals that any EPS will be limited in its application so as to only affect new coal plant.
- We agree with DECC's view that the EPS for gas could put security of supply at risk.

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

- If the desired outcome is to stop the construction of new unabated coal stations, then the level should be set appropriately. If Government wishes to allow a new coal plant with partial CCS to be built then this also needs to be factored into the arrangements.
- Our expectation is that there will be an increasing number of very low power price periods in the UK market as low variable cost wind and nuclear generation penetrates the market. This will be reflected in steeper peak prices as mid-merit

plant, which will be needed for system stability, recover investment and operating costs over fewer hours. Care needs to be taken to set an emissions limit that maintains the requirement that any CCS installed is fully utilised despite the optimal load-factor of a coal-fired plant naturally falling through time.

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

- Yes. We agree the EPS should only apply to new plant and be 'grandfathered' at the point of consent. It is very difficult to fix in advance the economic life of assets such as power stations. It may be better to set a consent life of, say, 40 years.

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

- In principle we would agree that existing plants that are effectively rebuilt so as to become a new plant should be captured by these new rules.

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

- Yes.

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

- We would support the proposal to "zero rate" biomass fuel when calculating the emissions from power stations which use biomass as a fuel.

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

- It is prudent to make provision for emergency situations. The proposal to implement EPS via annual limits is sensible and allows for short-term fluctuations in emissions performance.
- Whilst the theoretical attractions of allowing additional short-term emergency relief are obvious, examples such as operating a CCS coal plant without CCS could be dangerous. The commercial benefits to the operator of having emergency relief may distort the original intent.
- Also, care must be taken that the market does not presume this to happen in every "emergency" so that it becomes the norm. This could then result in other generators not investing in back-up capacity which then makes the "emergency use" become the expected default response.

## Options for Market Efficiency and Security of Supply

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

- We agree that the security of supply consequences of large amounts of intermittent generation need to be properly addressed.
- We also agree that we cannot be certain that sufficient capacity will be maintained on the UK system given the scale of regulatory uncertainty currently affecting the market.
- We do not believe that this is an issue in the near term and note the UK market has historically performed well in delivering secure electricity supplies.
- However the industry framework needs to be robust against such a situation arising as generators react to a complex mix of market, regulatory and environmental drivers.
- We feel that the consultation insufficiently distinguishes between the related but distinct issues of supply adequacy and system reliability (i.e. sufficient flexible capacity to cover wind intermittency).
- We therefore propose the introduction of a reserve market, similar to that described on page 122 of DECC's Impact Assessment. This would include a 'three year ahead' auction for reserve capacity, in which all options including existing plant, prospective plant, demand side response can participate; the price paid for their capacity will reflect the actual market need at that time.

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

- We agree that the current market arrangements relating to cash-out need to be reformed to allow better price signals to incentivise industry to deliver system security.
- We can no longer be confident that capacity adequacy will be maintained over the long term in the face of the levels of regulatory, market and environmental uncertainties now affecting investment decisions around existing and new plant.
- We believe there are a range of issues associated with the current reserve arrangements:
    - Free-rider and inconsistency issues: some reserve capacity is currently provided for free, by plants offering into the BM; whereas less flexible plants that are not being dispatched, such as oil plants, are being paid 'warming contracts' to be on a standby basis over the same time of need.
    - The closed bilateral negotiation for ancillary services means that the mechanism lacks transparency and thus it is difficult for utilities to make investment decisions based on the potential value of ancillary services
    - Last resort measures such as voltage reduction are not priced into the market when they are utilised
- A targeted capacity mechanism, as described (the Swedish model) is only workable as a backstop mechanism for dealing with supply adequacy with strong limitations on the interaction of the contracted plant with the market.
- Given the need to reconcile any capacity mechanism against real time behaviour we do not see it as being distinct from improvements to the current market. Capacity, reserve and energy are a continuum that need to be dealt with in a coherent, interlinked manner.
- We therefore support the introduction of a market system that provides signals for adequate capacity and rewards flexible operation and the provision of real time reserve as outlined in page 122 of the EMR Impact Assessment.

A Market-Based Alternative

- We support the concept of creating an additional market to reward flexibility which can provide an additional revenue source for fossil plants that otherwise might close due to falling load factors.
- We also believe that a coherent reserve market framework could be developed that would provide some longer term revenue signals for marginal capacity as well as shorter term operating incentives.
- We believe an alternative to the proposed targeted capacity payments that is more market based and which could offer a solution to both supply adequacy and supply reliability issues is to create a real time reserve market in parallel to having a 3 years forward auction for annual reserve contracts, such that:
    - The System Operator (SO) is responsible for delivering Security of Supply, and is the buyer of reserve capacity
    - Generators or demand-side participants that meet specified technical requirements (e.g. sufficient response time) can bid for the 3 years ahead reserve contracts.
    - Generators or demand-side participants can subsequently re-trade their reserve commitment in the bilateral or real-time markets prior to delivery if they determine that it is more valuable to dispatch for energy production or consumption, or that other generators can provide the contracted services more cheaply
- This is effectively an extension of the current NGT reserve contracting arrangements into a transparent forward and real-time market. It would look similar to the model for reserve markets outlined in the Impact Assessment associated with the EMR consultation, with the added element of a forward reserve auction to provide a longer term price signal for investment in life extensions or new build. Such a system would introduce effective short term values for reserve that would provide incentives and investment signals for flexible and marginal plant, would give generators some forward price certainty and would provide appropriate prices for the reconciliation of forward reserve commitments versus actual reserve provision.
- Both the three year forward market and the real time market would include demand-response as appropriate and be designed to allow sufficient response times to maintain security of supply.

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

- The way that a targeted capacity mechanism would interact with the wholesale market depends on how the mechanism is designed. Issues such as how the contracted capacity is used (last resort or economic), and how the market price is determined when the contracted capacity is used are key design issues. See our answer on Q24 for further details.
- If a targeted capacity mechanism were introduced in a way that limits the risk of spilling over to the rest of the energy market then it should have limited impact on wholesale electricity market prices.
- To the extent that it fails to address the intermittency issue and other flexibility solutions are not implemented, then this could result in periods of extremely high prices when the market has to use price to curtail load so as to balance the system, for instance during periods of low wind.

***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.***

- We do not think that the proposed design (Swedish model) adequately deals with the flexibility issue and there would have to be parallel changes to the energy and reserve markets to deal with this as flexible operation becomes more important from a system perspective and as reserve operation provides a greater proportion of the revenues that marginal plant need.
- It is our view that an appropriately designed reserve market solution could address both adequacy and flexibility issues in a more coherent manner than possible through targeted contracts with last resort capacity.
- Given the mix of technical characteristics of the plant on the system that could be included within a capacity market, and what this actually means in terms of their ability to provide energy as needed, we believe that there should be some differentiation between types of plant in any capacity market depending on system need. This will be defined by the type of product that the auction body (e.g. SO) determines is required.
- We believe that any capacity system should be targeted in the sense that it applies to plant that can provide the reserve service(s) required by the system, but otherwise should be open to all plants that can provide the service.
- Explicitly, this means that reserve that is partly provided for free today, by some plants offering into the Balancing Market, would in the future have to be paid for. This becomes essential as we move towards a future where fossil plants will run less and the provision of reserve becomes their key role. Such plants may retire as a result of falling revenue unless there is an explicit mechanism that rewards them for provision of reserve.
- Some elements of a potential reserve market could be:
    - Market based: allows the pricing and valuation of reserve capacity to be competitively determined in both a 3 year ahead annual auction and a real time reserve market ;
    - That generators and demand side participants and the System Operator can optimise their contracted reserve positions and trade reserve commitments prior to Gate Closure.
    - Allow forward price visibility: via auction for 3 years ahead through annual reserve contracts
    - Impose a system security and reliability standard on the System Operator: this creates an explicit demand for reserve capacity and the SO can meet this requirement by contracting for reserve capacity that meets certain flexibility characteristics.
    - Transparency: in the price formulation process and the calculation of reserve requirements
    - Early implementation: to allow sufficient time for the reserve market to establish credible and a track record that can then be used as a basis for investors to make new investment decisions or assess life extensions for existing plants.

***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?***

- The proposed targeted capacity mechanism, particularly if this is last resort capacity, appears very narrow in scope and if the contracted capacity only covered emergency use the mechanism would have little beneficial impact on the investment opportunities described above, except possibly for some demand response.
- The low frequency of intended use of last resort dispatch may create challenges in assurance of demand response availability until an actual system crisis.
- We believe that a more transparent and long term reserve market would provide signals that would expand opportunities for the technologies identified above as well as for marginal generating capacity.
- The establishment of a clear market based price signal should offer such technologies more certainty as to their long term value.
- Our alternative option lends itself to a range of known and unknown technologies competing to invest, such as demand side response, interconnection, storage, and other option.
- A key enabler for efficient demand-side response is proper market price signals. To the extent that out-of-market policy intervention dampens market prices, this will impede demand-side participants' ability to respond in a timely and appropriate manner.

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

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

- If the targeted mechanism were implemented as proposed, we believe that it is essential that the capacity only be dispatched as a matter of last resort. When utilised in such a way, it would be important that it results in very high Balancing Market prices (consistent with full cost recovery over very few running hours) so that the spot market price signals are not corrupted.
- However, as we have explained above, we do not believe that it adequately addresses the need for flexibility on a daily / hourly basis to deal with wind intermittency.
- If the "emergency" reserve was dispatched on an economic basis then we believe that this would distort the market energy prices by artificially dampening price spikes to the detriment of other generators outside the capacity support arrangement. This would depress investment signals leading to less investment and a corresponding increase in the scope of the targeted capacity secured under separate arrangements.
- We have therefore proposed <u>an alternative model that is more market based that could offer a solution to both supply adequacy and supply reliability issues. It is to create a real time reserve market in parallel to having a 3 years forward auction for annual reserve contracts. This is our preferred approach (see answers to 20, 22, and 23).</u>

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

- Our proposed alternative model of a reserve market would allow for the assessment of the requirement for any locational signals as part of the security standard which the SO would be responsible for delivering. Such locational elements could then become part of the technical parameters for any specific reserve auction the SO undertakes.

- It should be noted that some locational pricing signals exist within the current market arrangements, eg transmission charging, and these will need to be taken into consideration when determining any requirement for additional locational pricing signals.

## 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?***

- As a business that operates in competitive deregulated markets, we are generally comfortable with taking price risk. We believe that competition and innovation reduces the cost of electricity to customers and that less intervention is generally better.
- However, given the large capital investments required for low carbon generation and the fact that no low carbon generation can compete with fossil generation in energy markets at today's cost of carbon some form of price support mechanism is necessary to secure the delivery of the required levels of investment
- Our support for the proposal for targeted capacity mechanism is limited and contingent, as we have explained in the appropriate sections. We think there are market based alternatives, such as a reserve market which could work equally well within Packages 2 or 3.
- Apart from the targeted capacity mechanism element, we believe that both the Government's preferred Package 3 (with CfDs) and its alternative of Package 2 where PFIT replaces CfDs are workable proposals and should put in place the necessary combination of market arrangements and new regulations to encourage the electricity industry to deliver the Governments low carbon policy objectives.
- Clearly there is still a lot of detail that is not yet defined which could give rise to issues that cannot yet be foreseen. For either CFD or PFIT system, details on institutional arrangements and funding of support system are crucial, and w e also believe that an area at significant risk in this regard is likely to be the capacity support mechanism which is particularly technical and where interactions between the capacity and energy markets could be complex.

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

- We have outlined above that Centrica is comfortable with commodity price risk and that we believe that the alternative Package 2 represents, from our perspective, a fully workable proposal.
- The PFIT is closer in design to maintaining the competitive market landscape, which we believe benefits customers. It is therefore more consistent with our preference for maintaining a pro-market approach more generally.
- As discussed above, our support for the proposed targeted capacity mechanism element is limited.
- Detailed views on the relative merits between Package 3 and Package 2 will largely depend on the details surrounding specific mechanism design and implementation issues.
- We agree with the Government's assessment that neither package 1 not 4 are desirable nor capable of delivering the necessary investments.

- However, implementation of the EMR package would create a complex electricity market with a high degree of ongoing Government intervention.
- We believe that a simpler, more market-based alternative should also be considered.
- Such an alternative is the introduction of a 'Portfolio Carbon Standard' that places an obligation on all suppliers to sell electricity with a capped carbon intensity (see annex). This creates a premium market for low carbon electricity.
- Aside from the simplicity, the key advantages of this approach are that:
    - Government does not have to 'pick winners' in terms of technology
    - It is a lower cost-alternative, relative to achieving decarbonisation goals solely through the carbon price.

***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?***

- As the Government is well aware, achieving new low carbon generation is dependent on many factors including consents, timely new transmission investment and grid connections as well as market arrangements. The impact of the low carbon transformation on networks will depend in large part on the specifics of the technology solutions adopted. If there is a large growth in embedded photovoltaic generation (as has recently occurred in Germany) then this will have much more impact on distribution networks than large centralised generation solutions. Similarly, the development of electric vehicles and the role of demand side management is currently difficult to predict in terms of scale and timing but could have significant network implications.
- We believe that the combination of CfD for low carbon support plus the peak capacity tender could lead to the progressive loss of the whole competitive energy market.
    - Where baseload low carbon, renewables *and* peaking plants (contracted reserve capacity) are coming on-line under government intervention (i.e. CfDs and Targeted Capacity Payment), there is a significant risk that merchant thermal plants operating in the mid-merit and peaking segment will be squeezed out of the market.
    - As this happens, the system will gradually move to a "centrally planned" one where we have long-term support contracts for low carbon generation, together with centrally planned capacity to cover mid-merit and peaking segments.
- The impact of this on retail competition is potentially significant and far-reaching and we believe this was not sufficiently considered within the consultation.
- Furthermore, if CfDs and a targeted capacity market undermine energy market price signals, then the case for smart meters and a smart grid is severely eroded, as well as wider demand-side initiatives, since these rely on having a market that allows real-time response to price signals.

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

- We agree with the Government's analysis that Package 1 – relying on Carbon Price Support, the EPS and capacity mechanisms – is unlikely on its own to deliver sufficient investment in low carbon investment.

- We also agree that Package 4 – a full FIT, Carbon Price Support, the EPS and capacity mechanisms – looses the benefits of a competitive market and disbenefits customers.
- We agree with the Government's conclusion that Package 2 and Package 3 are workable options, and that the components of either CFD or PFITs, plus carbon price support, an EPS and a capacity mechanism can work together in principle.
- Inevitably there is considerable design detail also to be worked through that will expose any specific issues and interactions.

**<u>Implementation Issues</u>**

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

Risks are:

- Working up the details of the proposals;
- Resourcing and completing negotiations on the forms of contract to be used
    - o details associated with contract operation such as payment timings and flows
    - o credit requirements and security over assets
    - o making sure that the arrangements would be compatible with future financing alternatives
    - o arrangements to deal with construction timing uncertainties
    - o change of law risk
- Legislation timelines
- Setting up the new organisations (buyers of Cfd/PFIT)
- Defining the role of the existing Governance bodies such as Ofgem
- EU approvals/ State Aid
- Payment / cashflow mechanisms for funding the low carbon revenue support mechanism. E.g. how and when are the costs of the low carbon support arrangements passed on to suppliers/ customers
- Working capital issues associated with mismatch of cashflows
- Provisions for bankruptcy of suppliers or generators

Package 1, which would not involve the establishment of a counter-party, would be easier to implement. However, it would not deliver the investment required.

***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?***

- Auctioning is the more theoretically appealing approach to price discovery. However, it is hard to see how they could work in practice, particularly in the early stages of low carbon technology deployment.
    - Successful, effective auctions require a surplus of bidders, but we have the opposite situation in UK for low carbon generation. In offshore wind all projects are needed to meet the renewable energy targets. In new nuclear there is only one bidder currently in a position to participate (EDF/ Centrica JV) within the next year or so.
    - Efficient auctions also need comparable, homogenous products, but every new nuclear and offshore wind project is different in many aspects(timing, stage of development, connection & planning, site etc)
    - With the Danish examples quoted in the consultation, the SO or Government auctioned a complete package that included the site, grid connections as well as the results of site investigations. In the UK, the offshore wind sites have already been auctioned and connections and site development are the responsibility of the site holders who are also committed to development plans. In order to replicate this system, the Government would need o buy back these same sites, carry out all the site investigation and consenting work, only to then auction them off again, which would make little sense.
    - Similarly for new nuclear all the NPS agreed sites are also in private hands.
    - In addition, low carbon development projects typically have very significant pre-construction costs (running into the 10s of £M), which potential investors would be reluctant to commit to without a clear understanding of the level of support the development would receive and its likelihood of proceeding.
- Implementing a system of auctioning would also mean that investors do not know whether any support will be available, or at what level, until the auctioning process is complete. This would act as a disincentive to investing in high risk projects with high pre-bid costs, putting off many investors and impacting confidence throughout the supply chain.
- One option would be for all losing bidders in the auction to have their bid costs repaid. However, the total cost of this to the Government, given the large pre-bid costs associated with many of the qualifying technologies, is likely to be significant.
- Auctioning also precludes developers from driving industrialization of the supply chain given the lack of visibility on long-term planning and ordering associated with the uncertainty of being successful in an auction.
- In addition, practical experience demonstrates that Government auctioning processes can cause significant delays and be flawed in their design and implementation.
    - The CCS Demonstration competition was first launched in 2007, no project has yet been awarded the prize.
    - OFTO was a complex, costly and lengthy design and administration process whose costs do not clearly outweigh the benefits.
    - Government had to take over ownership of Intercity East Coast Line rail franchise.

    - Under the NFFO auctions process, many bidders entered unrealistic bids in order to be successful in auction, but were then unable to bring forward developments on this basis.
- We acknowledge that a system of individual negotiations to determine levels of support specific to every development is also undesirable.
- A more practical approach, particularly in early stages, is an administered process that builds on the precedent of the banding review process for the RO, in which Government sets the price level with periodic reviews expected.
    - The level is set on the basis of a range of factors e.g. commodity price trends, information disclosure from participants and the supply chain, independent advice to the Government and the volume of investment Government wants to encourage.

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

- We do not believe any structural changes would be necessary within the market, which can continue with little change.
- It is important to identify how the contract counter-party would interface with the market and the market participants, and think through various scenarios such as what the sanctions would be if the supplier does not pass on funds collected from customers or if a supplier or generator is declared insolvent.
- Under either a CfD or PFIT system, many detailed issues would need to be decided, which is likely to be lengthy in terms of process. The range of issues for further determination may be more complex for a CFD system than PFIT, and include:
    - What is the scope and role of the contract counter party (Agency Vs Authority)
        - Agency will have a clearly defined task to execute (current discussion points towards this option).
        - Authority will have a wider overarching objectives (e.g. 30% of renewable electricity by 2030) that they need to deliver.
    - Who will have the responsibility?
    - Change in legislation and timing
        - It is expected that primary legislation will be required to establish a counterparty with cost recovery capability and to change supplier licenses
        - If Government wants to pass legislation by Spring 2012, it will need to instruct parliamentary counsel by summer 2011
    - Detailed elements of the contracts
        - Indexation: as we have discussed, it will be critical that the selection of index matches the technical characteristics of the generation.
        - Premium or CfD strike price escalation: the long term nature of the low carbon support contracts will necessitate consideration of the appropriate form of escalation for the premia or strike prices.
        - Length of contracts: there will be a complex trade-off between length of contract, price, and financial stability.
        - Availability Vs capacity related payments (as discussed above)
        - Penalty clauses
    - Flow of money and settlement process
        - Need to work out the settlement process that the Agency/Authority needs to carry out

- Need to considers what happens when a supplier becomes insolvent, and how the Agency/Authority can recover its cost

***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?***

- Government will need to undertake substantial modelling under a range of scenarios to identify possible unintended consequences of any mechanisms implemented as a result of EMR.
- It will also be necessary to work closely with the industry as EMR progresses to better allow for identification of possible unintended consequences, and practical, mitigating actions.
- It may also be appropriate to undertake regular review of mechanisms implemented, as their effect on the market can be seen.

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

- Provided that a legislation slot can be achieved in 2011/12 and the White Paper is published on schedule in spring 2011 then delay risks are manageable. The ongoing RO rebanding review is already introducing some uncertainty for renewable projects which the Government has addressed by speeding up the process.
- If this timetable slips, then interim arrangements will be needed to maintain momentum for the early low carbon projects such as CCS and nuclear that are not covered by current arrangements.
- If CfD were adopted, it is important to note that implementation of CfDs (including putting in place the necessary institutional and legislation arrangement and for the government to strike an agreement with industry on all key contractual design issues), is likely to be a lengthy process. To the extent that there is a perceive risk of supply adequacy, there may be a need for interim solution in order for the industry to move forward with investment decision.

***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?***

- The grandfathering principle should be that the commercial intent of the regulatory environment in place at the point that an investor committed to a project should not be changed. Implementing any policy that alters the commercial structure for existing projects is likely to result in investors losing confidence in future support mechanisms. It will also result in parties becoming embroiled in lengthy contract renegotiations and potentially contract disputes.

***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 lowcarbon in 2013/14 (subject to Parliamentary time). Which of these options do you favour:***

– ***All new renewable electricity capacity accrediting before 1 April 2017 accredits under the RO;***

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

- We support the principle of allowing developers a choice between accrediting under the RO or the new mechanism. However we are concerned that the current proposals on timing do not in reality allow for a sufficient period of choice.
- The over-riding issue with the transition between the RO and the new system of low-carbon support is that the RO is grandfathered at accreditation which occurs after the point of first generation, whereas the new mechanism will be a component of project financial close, occurring much earlier in the project cycle. As projects do not always get built to plan however, the construction risk is such that projects entering construction cannot know if they will deliver the planned operational date and this threatens the level of support for the project. This uncertainty is a major flaw in the current RO design and one that could, and should, be removed. However, in the transition period to a new support mechanism, this risk not only threatens the level of support but the support mechanism as well.
- 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 first power from those projects is to be achieved before closing of the RO and, as a result, achieve RO accreditation by the deadline. For large offshore wind projects, the latest RO final investment decision is likely to be made in 2014, for biomass projects even earlier. After this investment point, the developer may not have confidence in the new, untested mechanism (either CFD or PFIT) and so any uncertainty on construction may lead to a decision to delay investment until confidence in the new mechanism emerges. It is therefore clear that if we wish to avoid a very damaging investment hiatus, renewable project developers must be offered a period during which they can chose with confidence between the RO and the new mechanism.
- We suggest that renewable projects could be grandfathered under the RO at the point of pre-accreditation at any point up to 31$^{st}$ March 2017, with grandfathering subject to achieving full accreditation by 2020. This would allow projects to choose between the two mechanisms for a period of up to 3 years, thereby smoothing the transitional phase and mitigating the risk of an investment hiatus.
- It should also be noted that large-scale offshore wind projects may take up to 5 years from first power to completion and that under recent modification of the RO, offshore wind projects can phase in grandfathering over a 5 year period. However, under the transition arrangements proposed, these projects could not receive 20 years of support under the RO for all turbines; 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 without a change to the proposals there is unlikely to be a realistic choice of support mechanism for these developers.
- We believe a sensible approach could be to extend the end of the RO beyond 2037 for this category of long build programme projects, to ensure that there is no delay in financial investment decisions in the period 2013 – 2015.
- Without such an extension of RO beyond 2037, it is likely that future banding reviews will need to deliver a higher ROC band for projects in this category to provide acceptable project returns over the shortened duration of support.

***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?***

- One concern regarding the RO is that the output of renewable projects is variable making the process of setting the target inherently uncertain. This leads to a criticism that the recycle value can over-reward projects at the expense of the consumer. However, once the RO is closed to new projects and 'vintaged', we believe it will be possible to set the target with reasonable accuracy, save for the variability of co-firing volumes. Co-firing is not grandfathered and we do not believe it should be. Further, we believe that there now is an opportunity to support all non-grandfathered renewable technologies under the new low carbon mechanism. This will have the benefit that the calculation of the Obligation in the Vintaged RO need only make allowance for variation in wind and rainfall (for hydro projects) rather than also the variable output of large cofired plants. This will have a significant impact on the ability of DECC to control the RO's capability to over-reward projects, with the consequent benefit in consumer costs and ultimately ensures that the Vintaged RO will behave in a very similar way to a Premium FIT.
- We believe that supporting such non-grandfathered technologies outside the RO would provide greater certainty to the remaining co-firers, greater certainty to government in setting the RO target and better value for consumers.

***38. Which option for calculating the Obligation post 2017 do you favour?***
– ***Continue using both target and headroom***
– ***Use Calculation B (Headroom) only from 2017***
– ***Fix the price of a ROC for existing and new generation***

- We believe the second option of using Calculation B only from 2017 is the only feasible solution, at least until 2030.
- W we recognise that in the final years of the RO, continuing to use both target and headroom calculations is likely to unnecessarily over-reward projects still supported by the mechanism The second option (using Calculation B only) takes the floor on the size of the Obligation away and allows the target to fall towards zero in the final years 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 and ensures value for money for consumers.
- We strongly oppose the suggestion that Ofgem buy all ROCs at a pre-determined price at any time in the near or medium term. We believe that the mere suggestion of this mechanism is damaging to the market and the proposal to introduce this approach in 2013 would clearly damage investor confidence in relation to both existing and new PPAs for reasons outlined below:

    1. New PPAs - Every PPA negotiation, with immediate effect, will have to take into account the potential for this mechanism to be introduced and so the

suggestion of the change has already altered the behavior of market participants.

2. Existing PPAs - Fixing the price of a ROC would disrupt or frustrate potentially hundreds of renewable PPAs that are currently in force. This would require widespread bilateral re-negotiation of existing PPAs and it is clear that there will be winners and losers in every deal, with lawyers firmly in the winners' camp. This move would demonstrate a damaging lack of commitment from Government to the notion of grandfathering and risks undermining the confidence of those that have backed the renewable power sector.

- We can see the potential in the final few years of the RO, when there are a limited number of large projects supported by ROCs, that the sudden failure of a large project could result in a ROC shortfall and hence the remaining projects would be over-rewarded. We consider this a small risk of limited impact on consumers, but if this is DECC's concern there is potential for a Fixed ROC to be introduced at a very late stage in the life of the RO such that it is beyond the expiry of any existing PPA. In this way all existing investments would be protected.
- We suggest that the earliest possible date for the implementation of the Fixed ROC would be 2030. In order to minimize damage, it is important that DECC sends a clear and immediate signal to the market that this option will not be introduced until at least 2030.

## Annex:

### A Portfolio Carbon Standard

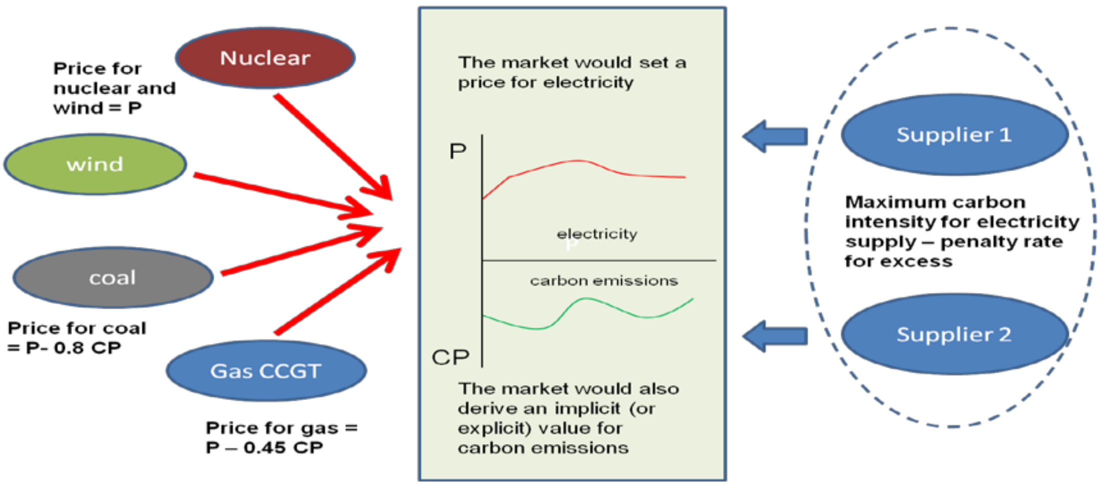
Within a Portfolio Carbon Standard, Government sets limits on carbon intensity for electricity suppliers:


Suppliers would have to demonstrate on a periodic basis the carbon intensity of the electricity that they provide to their customers.

This would require some form of certification on generation so that the emissions could be tracked. A market would develop in the certificates in parallel to the electricity market to enable efficient sourcing of electricity and trade between suppliers.

Suppliers would be penalised for excess emissions at a rate that provided an incentive for the development of low carbon generation, potentially the cost of offshore wind in the UK context

The market would derive an implicit value for carbon emissions.  This is because suppliers would forecast the long term value of carbon emissions and factor this into their portfolio choices. This would show up as a higher long-term price projection for low carbon choices: generation with higher carbon emissions would have a lower expected price as the implicit cost of the carbon emissions would be deducted by the buyer. Low-carbon generation technologies will compete to offer the best value combination of electricity and emissions.




How it would work in detail:

- Government would define a declining carbon intensity standard to apply to all electricity supplies on an annual basis out to 2027 initially and then extending in line with each new carbon budget.
- Suppliers would have to demonstrate on a periodic basis (eg annually) the carbon intensity of the electricity that they provide to their customers.

- This would require some form of carbon intensity certification on generation so that the emissions could be tracked. A market would be established in these certificates in parallel to the electricity market to enable efficient sourcing of electricity and trade between suppliers and generators in these certificates to meet the annual intensity targets.
- Suppliers would be penalised for excess emissions at a rate that provided an incentive for the development of low carbon generation, potentially the cost of offshore wind in the UK context. Some level of banking and borrowing would be necessary to smooth annual price volatility in the certificates.
- Suppliers and generators would forecast the long term value of the carbon intensity certificates and factor this into their power purchase portfolio choices.
- This would result in low carbon generation having higher revenue expectations in the long-term: generation with higher carbon emissions would have a correspondingly lower expected price as the implicit cost of the carbon emissions would be deducted by buyers of the power.
- Low-carbon generation technologies will compete to offer the best value combination of electricity and emissions – thus leaving the market to determine the technology mix and how best to deliver the specified intensity targets.
- Importantly from a customer perspective, the carbon intensity target would result in overall lower cost than a carbon pricing system implemented via a cap-and-trade scheme, as it associates allowable carbon emissions directly with customer load and thereby enables the customer to capture the value of this as a lower increase in bills. In a cap and trade scheme, the value of the allowable carbon emissions is captured either by generators receiving free allowances, or the central body responsible for auctioning these allowances.