There are a number of ways that the Government could determine the economic life of the plant for grandfathering purposes including:

- the financing term of the project;
- the accounting life of the assets;
- the commercial viability of the plant;
- a 'reasonable period of return'; or
- manufacturer's/engineers' view/warranty on the physical life of assets and their safe operation.

One of the simplest approaches would be to adopt the financing term of the project as the term for grandfathering. This would help to achieve the lowest cost of finance, but would not benefit the developer for a longer period than the investment horizon. However, while debt terms would be relatively explicit in their definition of tenor, the definition of the equity investors' return period would be subjective and possibly an area for negotiation. Furthermore, for many projects the financing structure or term may not be explicit, particularly when projects are financed 'on balance sheet' using corporate funds.

Both the asset life and commercial viability approaches are likely to result in a significantly longer grandfathering period than one based on the financing term. This may assuage any security of supply concerns but is not consistent with the Government's ultimate objective of decarbonising the economy.

The most practical solution may therefore be to establish a standard 'reasonable period of return' through a consultative approach. DECC could request views on an appropriate period, taking account of rate of investment and operating cost recovery. This same period would apply for all projects.

At the end of the grandfathered term, the generation assets would have a remaining 'useful life'. At this point, the plant would be exposed to the prevailing EPS limit, and the plant operator would need to consider the feasibility of:

- retrofitting additional abatement technology;
- running at constrained load factors; or
- closure of the plant.

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?

EDF Energy would welcome further clarity as to what constitutes a 'significant life extension' or what upgrades would apply. We believe that it is unlikely that there will be significant major plant upgrades to fossil plant apart from Selective Catalytic Reduction

(SCR), which the consultation document states will not be counted. We assume that the intention is to prevent an existing plant being replaced by an essentially new unabated plant that would be exempted from the EPS because it retained the grandfathered rights of the existing plant. It appears to be extremely unlikely that such an attempt could succeed. It would therefore be helpful in responding to this question if specific examples could be provided of the type of extensions and or upgrades that are envisaged as potentially falling within this category. We would be pleased to discuss this further.

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

DECC has proposed that future reviews are carried out in conjunction with the progress reviews for decarbonisation and CCS required by the 2010 Energy Act i.e. with the first reporting period ending in 2011, and further periods running on a 3-year basis starting in 2012. We agree that the reviews should allow the Government to closely monitor the early development of CCS demonstration projects and adapt emissions limits in line with progress.

We believe that CCS investors will require good visibility regarding the level of EPS set for a given development in order to define an investment case. To this end, limits should be set with a lead time of at least the development period required for CCS plant. Mott MacDonald[6] estimates the total development and construction period for a Coal CCS plant to be between 7 to 11 years. Of course, this includes a pre-development period during which investors will not need exact certainty over limits. However, we suggest that a lead time of at least five years be considered for each change to EPS limits.

An important consideration is the rate at which EPS limits will tend towards limits which constrains CCGT plant since this would have a more pronounced impact on baseload prices (either gas as the marginal plant would be more expensive, or alternative technologies would become marginal). This would be the case for an EPS limit which requires coal plant to be around 70% abated (with an approximate carbon intensity of 370g/kWh). An EPS limit which required coal plant to be fully CCS capable would have an impact on CCGTs, and an EPS which requires fully abated CCGT would effectively curtail any further investment in new coal unless coal CCS is exempted from the EPS for reasons of diversity of supply.

It is conceivable that CCGT CCS technology will develop at a faster rate than coal CCS, making it the less expensive option for new investment. In future reviews, the Government will need to consider whether an EPS which incentivises coal CCS development, but allows unabated CCGT to be constructed remains appropriate, taking expectations of commodity prices and security of supply into account.

[6] Mott MacDonald, UK Electricity Generation Costs Update, June 2010.

We believe that further clarity is required to what parameters would trigger a tightening of limits and would welcome more details on this to avoid the possibility of a hiatus in development in the lead up to a progress review.

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

The EU ETS only requires that generators declare their carbon dioxide emissions from fossil fuel sources. If the EPS was to be consistent with this approach, biomass would have a 'zero rate' against limits. However, work is currently being carried out by a number of institutions to understand the true carbon intensity of biomass and bioliquids, including analysis of the sustainability of the resource and the intensity of the supply chain. If the conclusion of these studies shows that the combustion of biofuels results in a net increase in carbon emissions, then this would rationally lead to an amendment to the treatment of biomass under the EU ETS. We would therefore expect that a consistent change would be applied to all mechanisms which are dependent on carbon emissions, including the EPS. We believe it would be in the spirit of decarbonisation to introduce biofuel carbon intensities to emissions accounting under the EPS, the EU ETS and any other associated mechanisms.

In order to apply a non-zero rate of emissions to biomass in the EPS in an accurate way, DECC would require a robust methodology for determining the net carbon intensity of the fuel. We recognise that this methodology has not been fully developed but that a framework for assessing the intensity of each stage of a biofuel's supply chain has been established by Ofgem as part of its consultation on sustainability criteria for bioliquids[7]. While this work does not conclude on the overall net intensity of biomass, it is a definitive foundation and a consistent approach could be taken both for treatment of biomass under the EU ETS and EPS.

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

EDF Energy believes that, in line with the Government's commitment to decarbonise the UK Generation sector, there should be no such exemptions made for CCS plant beyond the early demonstration plants.

However, if DECC is minded to grant exemptions to the EPS, we believe these should only be in the case of tightly defined emergency circumstances for CCS operational reasons. Longer periods of exemption would undermine the decarbonisation effort and investment in low-carbon technologies. These defined circumstances would be similar to those set out for operation of flue gas desulphurisation (FGD) equipment under the opt-in terms of the LCPD, i.e. on an annual plant bubble basis.

[7] Ofgem, DRAFT Renewables Obligation: sustainability criteria for bioliquids, 10 February 2011

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

We broadly agree with the assessment of introducing a capacity mechanism and believe it will be useful to understand why capacity payments may be necessary, which should then provide a fuller context in which to evaluate any mechanism.

Great Britain power prices had a capacity element in the Pool (1990-2001) but, since 2001, GB market has been energy-only. During this period the market has seen the development of new capacity, but this does not recognise the changing landscape as we make progress on our decarbonisation objectives:

- Increased penetration of intermittent plant will create a requirement for very low load factor peaking plant to meet demand when there is a low level of wind output.
- LCPD and IED will force low load factor coal, oil and gas plants to close.

Without capacity payments, the economics of new peaking plant will depend on very infrequent occasions of very high prices. The uncertainties about the magnitude of these peak prices, their frequency, and their acceptability leads us to believe that if left to itself, the market may reach an equilibrium with a lower standard of security of supply than we currently have.

This problem is unlikely to materialise until at least 2016, maybe later. However, we believe it is important to address this issue now to remove an uncertainty that will increase the risk associated with investment decisions in all forms of generation.

In particular, fossil fuel generators face a prospective reduction in profitability from 2013 as EU ETS Phase III brings the end of free carbon allowances. Furthermore, operators will need to make decisions within the next three years about their options for compliance with the IED. Investment decisions about affected plant should be informed by clarity about the proposed structure for rewarding the provision of capacity.

In practical terms, the mechanism may need to support the continued operation of existing fossil plant until the early 2020s as well as the introduction of new peaking capacity to replace it. The mechanism should enable rational economic choices between peaking plant and other solutions such as demand side response, storage and interconnection.

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

EDF Energy agrees that a capacity mechanism or a mechanism that reflects the value of capacity in the wholesale price is required.

We have analysed the specific proposal to introduce a targeted capacity payment and believe that, unless designed and implemented correctly, a targeted mechanism could depress wholesale prices, which could lead plant outside the mechanism to become unprofitable and risk the 'slippery slope' issue, raised in paragraph 31 of the Impact Assessment, where additional plant would need to be included in the targeted mechanism to remain profitable.

However, we believe it is possible for a targeted capacity mechanism based on last resort dispatch to avoid this 'slippery slope' by feeding back a cost signal into wholesale and cash out prices when the last resort capacity is used. In this way, peak prices can be maintained at a high enough level to ensure that all capacity is adequately remunerated.

EDF Energy therefore supports the Government's proposal to introduce a targeted capacity mechanism but we have some concerns that must be addressed in the design of the mechanism:

- The targeted approach should be done on a last resort basis – the alternative 'economic despatch' approach carries too great a risk of a 'slippery slope' (i.e. that plant without a capacity payment becomes unviable).
- Careful thought has to be given to the design of the mechanism to ensure that it ensures the right economic signal for capacity is reflected in the wholesale price on a stable basis – the impact on cash out prices has to be big enough to ensure the mechanism is effective but not so big as to expose generators and suppliers to excessive risk.
- The governance arrangements should ensure robust processes for objective review and updating of the mechanism.
- Further work should be undertaken to compare the proposals for Great Britain with the existing capacity mechanism in Ireland and the proposed capacity mechanism in France to minimise potential market distortions arising from different capacity mechanisms between neighbouring countries.

If these concerns cannot be adequately addressed through the targeted capacity mechanism, then an alternative approach should be adopted with a simple market wide capacity mechanism providing a flat payment to all available generation capacity and to reliable demand reduction capability. We discuss these points further in our response to Question 22.

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

It is important for all investors in capacity that they have confidence both that the provision of capacity is adequately rewarded (whether through energy price or capacity price) and that the mechanisms for achieving this are robust, stable and have the appropriate governance arrangements.

EDF Energy's concern about a targeted capacity mechanism is that, if not properly designed, it may provide adequate remuneration to the targeted capacity, but not to the rest of the market. This would have the effect of creating the "market distortion" referred to in paragraph 4.53 of the consultation document.

We believe that it is possible for a targeted capacity mechanism based on last resort despatch to avoid this market distortion by feeding back a cost signal into wholesale and cash out prices when the last resort capacity is used. In this way, peak prices can be maintained at a high enough level to ensure that all capacity is adequately remunerated.

By doing this, the risk of a 'boom and bust' cycle of oversupply and low prices followed by shortage and high prices could be mitigated.

However, to calibrate the right level of capacity payments and to reflect the correct value of these in the wholesale price presents some challenges. The right governance processes are needed to ensure that the mechanism continues to operate effectively and that the right price signals are maintained over the longer term.

These price signals should ensure that peak prices are high enough to provide incentives to provide adequate capacity. However, if they are too high, there will also be dangers from exposing generators to excessive risks from plant failure, or from the operation of intermittent plant.

We do not believe that a targeted capacity mechanism based on economic despatch can maintain these price signals and so, although superficially a cheaper alternative, it will lead to market distortion that will deter investment.

A mechanism such as Short Term Operating Reserve (STOR) has an important role to play but it is a mechanism designed for providing flexibility through spinning or standing reserve, rather than one for ensuring adequate capacity. Flexibility and capacity should not be confused; it is necessary to reward the provision of both:

- Adequate capacity to ensure that peak demand can be met (through the Government's proposed capacity mechanism); and
- flexible plant to enable the System Operator to balance the system (which can be procured by the System Operator through existing mechanisms).

Energy only wholesale electricity market
In the current energy only wholesale electricity market, wholesale power prices are reflective of Short Run Marginal Cost (SRMC) with an additional scarcity premium based upon the cost, size and probability of demand not being met (often referred to as "energy unserved").

Capacity margins have an influence on the level of additional scarcity premiums:

- During periods of tight capacity margins, this scarcity premium should increase with overall wholesale market prices being above SRMC.
- During periods of wide capacity margins, this scarcity premium should reduce with overall wholesale market prices being close to or at SRMC.

Investment in new capacity should be signalled when capacity margins tighten and where:

SRMC + scarcity premium > investment cost for capacity including acceptable return

Closure of the least economical existing plants should be signalled when capacity margins become too wide:

SRMC + scarcity premium < existing plants fixed and variable costs

Current capacity levels are maintained when:

SRMC + scarcity premium > existing plants fixed and variable costs

In the long term, a sustainable energy only market should have:

SRMC + scarcity premium = investment cost for capacity including acceptable return

However, the concern with the energy only wholesale electricity market is that sufficient signalling for investment in new capacity (i.e. SRMC + scarcity premium > investment cost of capacity including acceptable return) is only given when the capacity margin becomes tighter than is considered acceptable from a security of supply perspective (i.e. there is too much energy unserved).

Energy and capacity mechanism wholesale electricity market

A well designed capacity mechanism should deliver a desired security of supply standard (i.e. energy unserved at an acceptable level) in a sustainable and cost effective way. In the long term, a sustainable energy and capacity mechanism market would need:

SRMC + scarcity premium + capacity payment = investment cost for capacity including acceptable return

Introducing a market wide capacity mechanism would reduce the wholesale price as the scarcity premium would be reduced or removed by the lower risk of energy unserved brought about by the higher security of supply level. A well functioning and sustainable market wide capacity mechanism would need the capacity payment to adequately reimburse all capacity for the loss of the scarcity premium in the wholesale price.

Introducing a targeted capacity mechanism would also have the risk of reducing the wholesale price due to the lower risk of energy unserved brought about by the higher security of supply level. However, only a limited amount of capacity would be adequately reimbursed, through capacity payments, for any loss of the scarcity premium in the wholesale price. Therefore, a well functioning and sustainable targeted capacity mechanism would need the scarcity premium to remain in the wholesale price to ensure investors in 'capacity not receiving the capacity payment' would have sufficient returns to continue operations of existing plants and/or invest in new plants. Without the scarcity premium in the wholesale price, existing 'capacity not receiving the capacity payment' would be forced to close or require the capacity payment and this could undermine new plant being built. Therefore, the mechanism must be carefully designed to ensure that the scarcity premium remains in the wholesale price.

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.**

EDF Energy agrees that a separate central body should have responsibility for determining the required level of capacity in line with the declared security of supply policy objective.

The administration of the capacity mechanism could and should be part of the role of the System Operator and this would be consistent with its role in managing supply and demand in real time.

EDF Energy agrees that a capacity mechanism based on volume rather than price would be the most appropriate solution as it would be more likely to deliver the desired security of supply standard, which would need to have been set initially by the central body in conjunction with the Government.

Due to EDF Energy's concern about the risks of a targeted capacity mechanism, we have given careful thought to the implementation of a market wide mechanism. This has the advantage of recognising that all available capacity contributes to meeting peak demand. However, we recognise that a market wide mechanism runs the risk of over payment to generators not covered by CfDs, where they receive capacity payments that reimburse for the loss of scarcity value, but some scarcity value still remains in the wholesale price. Solutions that avoid double payments to generators may require significant changes to existing market arrangements, such as introducing an obligation to offer power at the SRMC.

Therefore, provided that the design of the mechanism and the associated governance arrangements can ensure that the mechanism will provide effective price signals for investment in all capacity, EDF Energy believes that the Government's proposal for a targeted mechanism is workable. However, as outlined in our response to question 21, the mechanism would need to be carefully designed to ensure that peak prices can be maintained at a high enough level to ensure that all capacity is adequately remunerated (i.e. the scarcity rent premium remains in the wholesale price).

It would be necessary for the mechanism to be designed to have Reserve Capacity dispatched on a Last Resort basis at a pre-determined high price for a projected number of running hours (see figure).

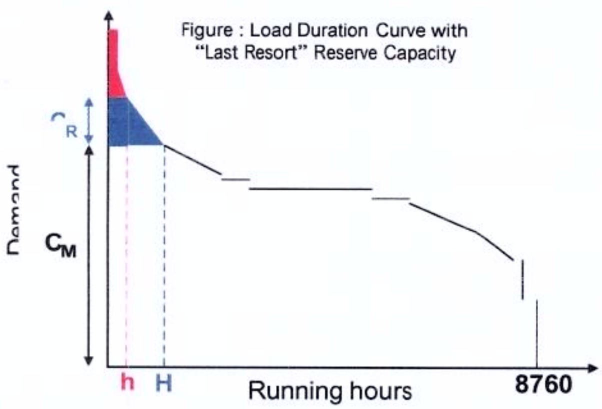


Figure : Load Duration Curve with "Last Resort" Reserve Capacity

C_M = Capacity provided by market
C = Reserve capacity
H = Projected number of running hrs for reserve capacity
h = Projected number of hrs of energy unserved
P_M = Wholesale price when reserve capacity not activated
= Related to SRMC of marginal plant
P_R* = Wholesale price when reserve capacity activated
= $\frac{\text{Investment Cost of OCGT}}{H}$ or pre-determined "high" price

	8760 - H	H - h	h
Marginal Plant	Set by market	C_R	C_R
Wholesale price	P	P	P
Energy Unserved	No	No	Yes

Last Resort despatch of the Reserve Capacity (**C_R**) at high price (**P_R**) would be required to give a transparent high price signal of scarcity rent premium for investment in capacity provide by the market (**C_M**) as capacity payments are only made to **C_R**. Economic despatch would not give the necessary price signal as **C_R** would be dispatched when economical, depressing the price for **C_M**.

In practice, the process could be as follows:

- Generators would need to signal to the Central Body holding the responsibility (e.g. System Operator in conjunction with the Government) the level of **C_M**. Generators currently commit to pay Transmission Entry Capacity (TEC) charges for two years out into the future. The Central Body could use this TEC commitment (or a separate commitment) as the signal for the level of **C_M** but would also need to monitor expected generation capacity and demand over a longer forward period to give adequate warning of potential requirements.
- The Central Body, in conjunction with the Government, would then need to determine the values of **C_R**, **P_R**, the projected number of hours of energy unserved (**h**) and the projected number of running hours for the reserve capacity (**H**).
- As **C_M** would be known, the Central Body would first set **H** and **P_R**. As an indication of the possible value of **H**, we would suggest that a value of 30 hours would give sufficient certainty of minimum number of hours where **P_R** set the wholesale price even in years where the number of high/peak demand hours is abnormally below the annual average number of hours with high/peak demand. Using the formula for **P_R** in the figure above and Redpoint's assumed fixed and

annuitized capital costs for an OCGT of £60/kW/year[8], the corresponding value for P_R would be £2000/MWh.

- Having set **H** and P_R, the Central Body would then need to assess the corresponding C_R that would be required to ensure that the projected number of hours of energy unserved (i.e. **h**) meets the Government's desired security of supply standard.
- Once the value of C_R has been set, generators and providers of demand-side response would tender for C_R. The tendering process would need to be sufficiently in advance for new build peaking plants (e.g. OCGTs) to be built and would exclude existing generators who had already signalled a commitment to be in C_M as if they were allow to tender and were successful, then the level of C_M would reduce, which required a corresponding increase in C_R. It would be our expectation that providers of this reserve capacity would receive capacity payments from the Central Body that would be sufficient to cover their fixed costs (including an acceptable return) and would be also be allowed to recover their SRMC when they generated.
- The revenue of reserve capacity price at P_R would then be used by the Central Body to offset the cost of the capacity mechanism (i.e. the capacity payments and SRMC of reserve capacity). The net cost of the capacity mechanism would be relatively small. It could then be billed to suppliers either based on the peak demand of their customers or smeared on a £/MWh basis.
- Investors would then be in a position to make plant life and new investment decisions for existing and new C_M plant based on the formulised scarcity premium (i.e. an expectation of P_R for **H** hours)

The following additional points should also be noted:

- If there was an under investment in C_M, the actual number of running hours (H_{actual}) of C_R at P_R would be greater than **H**, which would encourage continued operations of existing plant and investment in new plant in C_M.
- If there was an over investment in C_M, the actual number of running hours (H_{actual}) of C_R at P_R would be less than **H**, which would discourage continued operations of existing plant and investment in new plant in C_M.
- P_R would remain unchanged even though the actual number of running hours for the reserve capacity (H_{actual}) will normally be different to the forecasted number of running hours for the reserve capacity (**H**).

In summary, EDF Energy believes that a targeted capacity mechanism with reserve capacity dispatched on a last resort basis could be introduced successfully as long as the following design criteria can be met:

[8] Redpoint, Electricity Market Reform Analysis of policy options, p87, December 2010

- The Central Body is given the necessary signalling of the capacity provided by the market and can accurately determine the required level of reserve capacity.
- The average projected running hours and the wholesale price uplift during these hours can be set at a level that ensures peak prices are maintained at a high enough level to adequately remunerate all capacity.
- The mechanism is sufficiently stable and has the required level of governance to ensure timely, consistent and stable price signals that provide investors with the necessary confidence to make the required investments in a timely manner.

If not, then EDF Energy believes, alongside low carbon capacity payments for new investment, the Government should consider a flat capacity payment that would be payable to all available generation capacity, and potentially to reliable demand reduction capability.

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?

Electricity storage provides the opportunity to reduce the overall costs of electricity generation, by storing energy during periods when wholesale prices are low and releasing the stored energy when electricity prices are higher. Storage typically operates over relatively short timescales, e.g. a daily cycle. Therefore the main commercial driver for storage is the difference between low and high prices that are revealed by the market.

The roll out of smart meters will be an important enabler to providing a more dynamic relationship with energy consumers and demand side response is expected to play a greater role in managing electricity demand. EDF Energy believes that this is a further reason for ensuring that the wholesale prices that emerge from the reformed market arrangements represent a true reflection of generation costs, which should include any costs paid for by the system operator to secure standby and reserve capacity, as well as the costs required to keep the electricity system in balance. Such arrangements will allow the market to make optimal investment decisions in choosing between electricity storage options and building reserve capacity, as well as stimulating demand side response.

Interconnection can be used to improve the efficiency of the system by balancing natural peaks and troughs in demand across national systems and interconnection might also be used to import or export power if there are structural deficits/surpluses in the power sources. To date the UK system has generally operated in a way that has ensured there is sufficient capacity to meet domestic demand and we believe that, with the right policy choices, this will continue into the future. Therefore, the main reason for investing in increased levels of interconnection is likely to be the reliability and predictability of domestic generation sources, which will in turn depend on the choices we make regarding our future generation mix. Similar to storage, the important outcome for the market reform project will be to ensure that the wholesale market reveals a price that is an accurate reflection of the underlying generation costs, since this will ensure that market participants can see a reliable market signal to inform investment decisions.

However, the impact of introducing a capacity mechanism on incentives to invest in demand-side response, storage, interconnection and energy efficiency would be ultimately dependent on the type of capacity mechanism introduced.

Market wide capacity mechanism

- To the extent that demand-side response, storage, interconnection and energy efficiency are eligible to receive market-wide capacity payments, then incentives to invest would increase, but it would be important to ensure that the actions taken meet the instructions from the System Operator (e.g. metering, verification of actual demand reductions etc).
- Incentives to invest in energy efficiency and in demand side response not eligible for capacity payments would be reduced as the scarcity value in wholesale power prices would be reduced or removed.

Targeted capacity mechanism

- To the extent that demand-side response, storage, interconnection and energy efficiency are able to receive capacity payments, then incentives to invest would increase for those that become part of the reserve capacity (through capacity payments) and for non-reserve capacity (through energy revenues) in the event that the scarcity premium remains in the wholesale price. However, it would again be important to ensure that the actions taken correspond to level requested by the System Operator (e.g. metering, verification of actual demand reductions etc).
- For demand-side response, storage and interconnection not included in the reserve capacity and for energy efficiency, the incentive depends on whether there is an effective mechanism (as proposed for the last resort approach) to ensure that the value of capacity is properly reflected in the wholesale price.

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

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

As outlined in our response to question 22, EDF Energy believes that a well functioning and sustainable targeted capacity mechanism would require the Reserve Capacity to be dispatched on a Last Resort basis at a pre-determined high price.

Last Resort dispatch of the Reserve Capacity at the administered price would be required to give a transparent price signal of the scarcity premium for investment in capacity provide by the market as capacity payments are only made to the reserve capacity.

Economic despatch would not give the necessary price signal as the reserve capacity would be dispatched on short run economics this depressing the value of capacity.

We recognise, however, that there may be a need for the Last Resort capacity to be brought into service on a regular basis for testing purposes to ensure that it will be reliable when called upon.

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

The existing transmission use of system charges (TNUoS) already gives locational signalling for generation capacity. Modelling of the locational aspect of TNUoS is very complicated. Any inclusion of a locational element in the capacity mechanism would result in duplication of this complex modelling and would lead to inefficiencies. Therefore, EDF Energy believes that a locational element should not be included in the capacity mechanism unless it can achieve significant cost reductions (e.g. in transmission) that would not otherwise be achieved through TNUoS.

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?

EDF Energy welcomes the Government's proposals for market reform and we believe the proposals can be developed into robust market arrangements in which investors can have confidence; robust arrangements would be less subject to political risk. We look forward to taking these forward with Government to ensure that we achieve the right mix of instruments so that we have a coherent and sustainable package of reforms.

We believe that 'Package 3' in the EMR consultation represents the most balanced set of proposals that are capable of achieving the Government's policy objectives, provided our concern about potential market distortions created by targeted capacity payments can be addressed. If not, we would advocate a revision to package 3 to incorporate universal capacity payments. We believe that delivering energy security and investment in low carbon generation capacity requires a coherent set of complementary measures. In line with this view, we believe a balanced package of reforms should include both carbon price support and capacity payments.

Carbon price support will help ensure that fossil fuel generators pay a fair price for the pollution they emit. This could start at a low level, and rise over time, ensuring the true costs of carbon are reflected in market prices, as new generation comes on line. However we would agree with DECC's view that carbon price support is unlikely to be sufficient on its own in driving investment in low carbon generation.

In EDF Energy's view, the future market arrangements must provide a framework to bring forward sufficient generation capacity to meet electricity demand and have a sufficient margin to deal with the projected scale of intermittency that the UK system will have to deal with by the end of this decade. The existing market arrangements, where the market price is largely based on marginal production costs, are unlikely to provide a credible market signal to bring forward the required capacity; nor do they provide sufficient reassurance to underpin investment in capital intensive low carbon plant. We therefore believe that some form of capacity payment or recognition of the value of capacity is required to achieve the levels of security of supply that customers expect.

EDF Energy has previously drawn attention to the increase in the proportion of high capital, low marginal cost plant required on the system to deliver the UK's decarbonisation objectives. Under the current market arrangements, there is a significant risk that a system marginal price based on short-run marginal costs will not allow this plant to recover its full costs. We had advocated a form of Low Carbon Capacity Payment to resolve this concern; however, we expect that the proposed package will address it through a FIT.

DECC acknowledges the potential distortions to wholesale prices that could be created if a capacity mechanism targeted solely at peaking plant is implemented. The distortion would manifest itself in depressed wholesale prices, with the additional costs of providing adequate capacity being recovered outside of the wholesale market. EDF Energy believes that the costs of the targeted capacity payments should contribute to the composition of the wholesale electricity price and that this would provide a more efficient outcome for consumers with lower overall costs. We would seek further reassurance that these distortions can be avoided. If not, then EDF Energy believes, alongside low carbon capacity payments for new investment, the Government should consider a flat capacity payment that would be payable to all available generation capacity, and potentially to reliable demand reduction capability.

A further point for consideration is the issue that many forms of low carbon generation have relatively high capital costs and relatively low operating costs. Decarbonisation means that capacity becomes expensive but energy becomes cheap which then begs the question of whether an energy only market is capable of delivering low carbon capacity. EDF Energy's view is that an appropriate capacity payment would help ensure that sufficient low carbon electricity generation capacity is built.

The proposals in the consultation for a capacity payment are quite different to this and are designed to ensure adequate (fossil fuel) capacity is available to meet peak demands. It is possible that the CfD could be used to provide the security of the capacity payment required by low carbon generators and may be sufficient to provide investors with the required certainty. We have considered the interaction between different mechanisms and have come to the conclusion that these can work together but place a very high emphasis on ensuring that the wholesale price revealed to the market accurately reflects the value of capacity needed to maintain security of supply.

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

EDF Energy broadly agrees with the Government's assessment of the alternative packages that have been considered. As we have previously stated we believe that delivering energy security and investment in low carbon generation capacity requires a coherent set of complementary measures. We believe a balanced package of reforms should include Carbon Price Support and some form of capacity mechanism. We also recognise that an EPS, in principle, can be part of the reform package and could be a useful instrument to close out residual emissions from fossil fuelled plant. Since these three mechanisms are common to all the packages considered, the question essentially becomes one of whether carbon price support alone (together with the other three mechanisms) is a sufficient driver for investment in low carbon generation (package 1) and if not, what model of feed-in tariff provides the best incentive for such investment (packages 2-4).

EDF Energy considers carbon price support is a fundamental part of a coherent and holistic package of electricity market reforms. We agree with DECC's view that carbon price support is unlikely on its own to lead to the pace and scale of investment in low-carbon generation required for the UK to make its transition to a low-carbon economy, since other market defects would also need to be remedied. We believe it is important to be clear about the potential role of each of the measures and recognise the clear difference between correcting the defects of the existing market arrangements (e.g. through carbon price support) and additional measures that can mitigate risks for both customers and investors. We believe that incentives in the form of a feed-in tariff will be required to provide revenue certainty to all low carbon technologies, since renewables, nuclear and fossil fuel plant with CCS will all need to make contributions to the required decarbonisation of electricity production. We have previously highlighted the pros and cons of the different models of feed-in tariffs. As discussed in our response to question 26, we believe that package 3, which includes a FIT with CfD, represents the most balanced set of proposals that are capable of achieving the Government's policy objectives.

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?

EDF Energy believes that the package of reforms gives greater visibility to the Government's ultimate objective of decarbonising the UK economy. Low and zero carbon electricity will make a contribution of the decarbonisation of other sectors, such as heat and transport.

It is therefore important that the delivery of low carbon heating and transport solutions is coupled with the development and investment in the required infrastructure for transmission and distribution to manage the impacts on the electricity grid and on energy demand. For example, charging infrastructure requirements for electric vehicles will differ according to the location and density of the charging points and these will need to be managed to minimise impacts on distribution networks. This will particularly be the case in densely populated and areas of high demand. Concentrations of electric vehicle charging posts may require local network reinforcement, for example to substations and Low Voltage Infrastructure, in order to supply the additional demand on the network. Therefore, consideration should also be given to the capacity of the local infrastructure. However, the need for network reinforcement can be minimised with the development of a smart grid regime and if electric vehicle control systems can be designed to minimise electric vehicle charging at times of daily peak demand on the distribution networks.

In principle, we do not believe that the proposed package will have any adverse effects on the development of, and investment in, transmission and distribution infrastructure. However, it will be necessary to ensure this through the correct detailed design of the mechanisms.

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

Please see our response to Question 27.

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

We have addressed the main risks arising from the various options in our responses to Questions 9, 10, 11, and 22.

We also welcome Government's recognition that there is uncertainty as a result of its commitment to reform the electricity market which is preventing participants from taking effective decisions to invest in new low carbon electricity generation. Investors are at risk of having to make major decisions with limited visibility as to how the future market will operate. EDF Energy believes that the Government should provide as much clarity as early as possible so that informed decisions can be made on time to deliver a low carbon economy and that the Government is right to consider the need for interim arrangements to ensure there is no hiatus in delivering all of the required low carbon investments.

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?

We believe that the following conditions would have to be met to have successful auctions:

- A sufficient number of potential participants and a significant number of actual participants in each auction.
- Some form of pre-qualification to ensure bids are realistic and soundly prepared and/or criteria for contract award that are not solely financial.

- A greater amount of candidate bids than the quantity of contracts available in each round - so that there is an incentive to bid competitively in the knowledge that some projects can be turned down.
- Consequences and costs of an unsuccessful bid that can be tolerated by the unsuccessful parties, so that the risk of participation is acceptable.
- The risks of a project can be quantified and controlled sufficiently in advance so that a bid can be prepared to a sufficient accuracy and level of risk. Conversely, if there is a high level of remaining uncertainty, bids are likely to reflect the risk appetite of the bidders, rather than the actual underlying variation in project costs.

At present there are no details of the proposed auctions so it is not possible to determine the degree to which each of these potential concerns can be (or will be) addressed. These concerns do need to be resolved in full for an effective auctioning system. For example, the current UK arrangements for consenting and grid connections place large risks on renewable developers and the scale of these risks is not compatible with auctioning.

Another important example is the French experience of an auctioned renewable support scheme, which was unsuccessful for several of the reasons highlighted above. Even where risks are reduced in advance, such as the Danish offshore renewable auctions, there can still be difficulties in securing a reasonable number of participants, as the most recent Danish round demonstrates. There are also doubts whether the Danish system can be accurately described as an auction, at least in the classical sense that this consultation employs.

A further challenge for auctioning is that the difficulties in consenting in the UK, combined with the very demanding low carbon target, mean that any low carbon project that gains consent is likely to be needed at some point, whatever the cost. In effect there is a 'stack' of UK renewable projects of increasing cost. Projects higher in this stack can wait until their turn is reached, secure in the knowledge that they must proceed if the target is to be reached. Conversely, this provides a disincentive to the lower cost projects to bid early, knowing that other, higher cost projects will enter the auctions and secure higher prices at a later date.

In short, the challenge is that developers cannot bid early because they have insufficient knowledge of the project details to price accurately, and they cannot bid later because they will have incurred costs to develop the project details that are too large to write off if they are unsuccessful in the auction.

EDF Energy does not believe that auctions can provide a credible solution to awarding projects. We recommend that as a minimum, auctioning is deferred for renewable projects unless, and until, the issues above are resolved to the satisfaction of all stakeholders. In our view, the challenges are such that this would take a number of years, if it is possible at all. The Government should be prepared for the possibility that the issues for auctioning cannot be resolved for the particular circumstances of the UK.

For nuclear plant, the number of projects required is relatively small with much tighter restrictions on available sites.

Should auctions, tenders or the administrative approach to setting levels be technology neutral or technology specific?

The costs of different low carbon technologies vary significantly. Within the renewable technologies, the existing banding of the RO reflects this. Consequently, if auctions/administrative negotiations are technology neutral, the likely outcome is that the most cost-effective technology will dominate, to the exclusion of nearly all others. This would be undesirable in the longer term, given the need to diversify and encourage innovation, so a degree of technology specific levels is necessary.

How should the different costs of each technology be reflected?

EDF Energy believes that there should be a single contract for difference on the electricity price for all low-carbon technologies which could be supplemented by a series of technology-specific premia that are consistent with Government's energy policy objectives.

Are there other models government should consider?

A significant improvement to enable effective auctioning would be to implement measures that reduce the project risks before tender. For example, the Government could arrange consents and grid connections prior to tender, as in the Danish auction system. Other options (by way of illustration) include the block purchases of turbines by Government, reducing the supply chain risk.

The underlying principle is that the customer is ultimately funding the majority of the costs for delivery of the low carbon technologies. If the reduction of risk, through actions such as the examples above, reduces the overall cost, then they may merit consideration.

Should contract strike prices be set for individual projects or for technologies?

EDF Energy believes the strike prices should be, at least in the first instance for large projects such as nuclear reactors or large Round 3 offshore wind farms, set at the individual project level and move to strike prices being set for technologies in the longer term. Apart from technology specific premia, we have provided details of the key features that we believe should be included in CfDs in our response to Question 4.

Do you think there is sufficient competition amongst potential developers / sites to run effective auctions?

The challenge for renewables is that a very demanding target has been set for 2020. There is currently, and will be the foreseeable future, insufficient combined investment and delivery capacity in the market to develop the number of projects required to meet this target. As a result, the Government may be obliged to accept all the bids made in a round to maintain progress towards the target, especially if some projects have been deliberately held back for a later round. This may not deliver efficient competition, as bidders will be aware in advance of this shortfall in actual project supply versus the demand of the set targets. Auctions at this stage would attract very few bidders and may fail to capture the early-stage development costs for some large-scale low-carbon plant, such as off-shore wind, nuclear or CCS. Auctions may have a role to play in the future when technologies are mature and capital recycling is a more likely prospect.

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?
An auction could be designed to avoid excessive deployment of a technology. Equally, an allocated CfD or premium FIT approach could be subject to regular reviews that could alter price signals and manage deployment volumes, much as the current RO. That could also be an effective way of managing deployment levels.

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

These reforms will require the following changes to administrative arrangements:

- CfDs will require an Agency to act as counterparty to the CfD which may delegate the administration to a body with the right technical capabilities.
- The operation of Last Resort Capacity Payments will require a body to determine the required level of Last Resort capacity and the price which will be set when it operates; the administration of these arrangements could be delgated to the System Operator.
- The operation of EPS requires a periodic review of the EPS standard, which could be carried out by DECC.
- Carbon Price Support will be managed and administered, like other taxes, by HM Treasury and HM Revenue and Customs.

Of these requirements, perhaps the most critical is the establishment of the right arrangements to manage the cash flows arising from the CfDs. These arrangements will need to ensure that they meet the business requirements of energy suppliers by providing a predictable and relatively accurate forecast of cash flows to and from energy suppliers, so that these can be factored into any tariff or long term supply contract decisions. The arrangements will also need to ensure that adequate funds are available to make any payments due to the generators.

We expect that there will be a central Agency that will act as counterparty to the CfD with the generator and that there will be some other body (perhaps Elexon) that will manage the interface with energy suppliers and administer the requisite payments. As such it will have a critical role to play in both ensuring the right allocation of risks between various stakeholders (generator/suppliers/customers) and in the successful management of the scheme. We believe the Agency should be established to meet four key criteria:

- Have access to funds (either through to the tax payer or the consumer) and the ability to distribute excess funds when required – can it pay generators who are 'out of the money'?

- Have the appropriate arrangements in place to maintain a long-term credit position appropriate for an institution which is party to extremely large, long-term contracts which underpin the commercial stability of the industry – is it bankable?
- Be stable and sustainable in the long term – can it be trusted?
- Have the administrative capacity to deal with potentially hundreds of contracts for both large and small generators – can it do the job?

We do not believe that it is essential that the Agency is directly owned by Government and we recognise there may be advantages if it is not. There are existing examples of bodies such as the Non Fossil Purchasing Agency (NFPA) and Elexon that are owned by companies within the electricity industry and manage significant cash flows on behalf of the industry. The essential considerations will be that the Agency has the right governance arrangements and that it has, and will continue to have, the credit quality to act as counterparty to some very large long-term contracts. In this respect, the right to recover funds is essential; our working assumption is that this will be achieved through the right to levy a charge on suppliers, who will then recover the costs from customers.

From a supplier's perspective, one of fundamental key criteria that the new arrangements need to meet is the ability to provide a predictable cash flow in terms of the sums it needs to pass through to its customers. In addition careful thought will be required in limiting credit and default risks for suppliers.

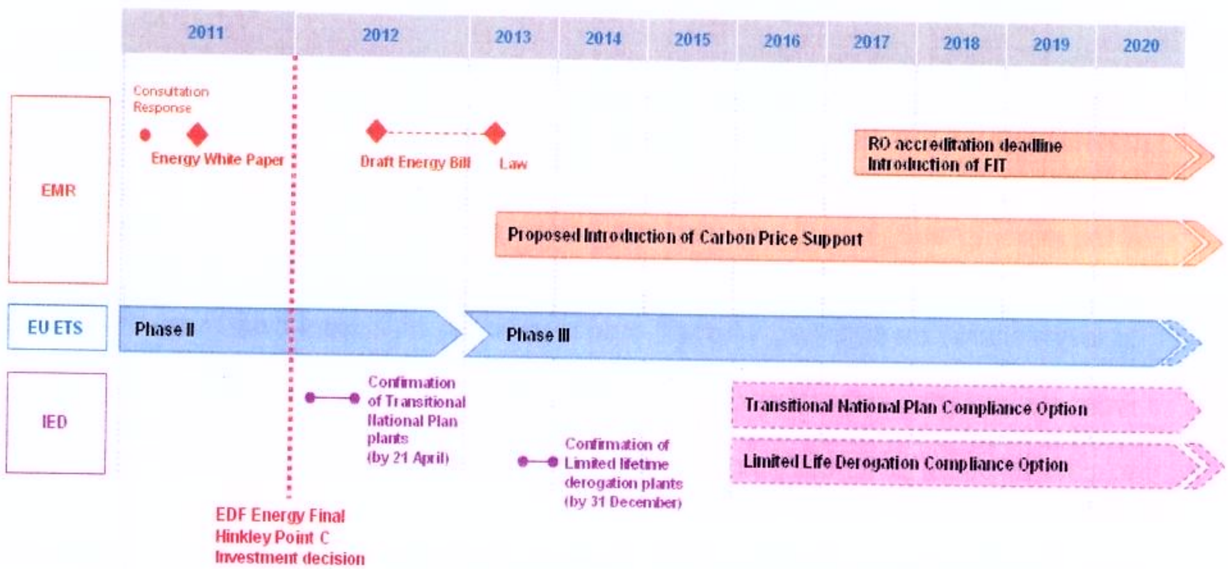
33. Do you have view on how market distortion and any other unintended consequences of a FIT or a targeted capacity mechanism can be minimised?

Please see responses to questions 3 and 4 where we have evaluated the potential benefits and drawbacks of the different FIT option and our responses to questions 19, 21 and 22 on capacity payments.

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

We agree with the assessment that there is a significant risk of delay while new market arrangements are put into place. Until there is clarity on the arrangements for the vintage RO, developers are likely to slow or suspend new project development and investors are unlikely to make a firm commitment. Consequently, the risk of delay is possibly greater than the Government's assessment.

The high level timeline below presents the interaction between the introduction of EMR and other changes driven by the move to Phase III of the EU ETS and the introduction of the IED. It clearly shows that investors are at risk of having to make major decisions with limited visibility as to how the future market will operate. The Government should provide as much clarity as early as possible so that informed decisions can be made on time to deliver a low carbon economy and is right to consider the need for interim arrangements in ensuring there is no hiatus in delivering all of the required low carbon investments. A clear statement from the Government that it will implement interim arrangements to help drive forward investment, swiftly followed by such implementation, will deliver the certainty that investors require. The absence of such arrangements may result in decisions being delayed. As has been recognised in previous statements of policy, delayed investment has the potential to jeopardise Government targets for decarbonisation.



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?

Immediate delay will be minimised by the earliest confirmation of the vintage RO arrangements, sufficient to give confidence that a project can go ahead with a low risk of insufficient future revenue from the support mechanism.

A deadline for commissioning and RO accreditation of April 2017 in order to secure the vintage RO may already be too soon for some of the larger projects that are currently under assessment, particularly where the projects are expected to be constructed in phases. As a result, these projects may have no choice but to hold back and proceed under the new CfD.

One option to avoid this delay would be to extend the period for projects to complete and accredit under the existing RO, subject to some form of pre-registration, qualification criteria and progress monitoring. However, the vintage RO itself should not be extended beyond 2037. The extended accreditation period would be provided solely to accommodate projects that intended to accredit before April 2017 but have been unavoidably delayed, rather than to extend the 'closing date' for new project proposals to join the RO.

Another option is to develop an alternative and earlier milestone for RO accreditation than the current milestone of commissioning. Industry has previously put forward a number of options for this, including financial close or the ordering of turbines. An earlier milestone takes out the risk of construction and supply chain delays, without altering the intention of the developer.

In order to avoid uncertainty in customer bills, there must be maximum transparency in the volumes of electricity that will fall within each support scheme (vintage RO and CfD) and the potential volumes that will be transiting from the existing to the new arrangements. This information must be provided well in advance of the delivery periods. The sooner this information is available, the less the risk associated with this uncertainty.

EDF Energy welcomes the FIT Review of the 5MW Fixed FIT scheme; this is an opportunity for further reform to be considered for the size of the scheme. Generators over 1MW are commercial operations which typically have energy market expertise. The existing FIT scheme holds a number of inherent risks, namely the balancing, post event cost changes and administration, all of which increase the relative unit cost to customers.

When considering the migration of the RO into a FIT with CfD approach, there is an opportunity to reduce customer costs and uncertainties by including all generators over 1MW in the FIT within the main CfD scheme.

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

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

We consider that a one-off choice by project between the two mechanisms would be useful during the 2013 to 2017 period. It would allow early lessons to be learnt from the awards of initial CfD contracts and give time for the CfD system to be optimised in response to this feedback. This would avoid a large pulse of new projects simultaneously joining an untested CfD scheme in 2017.

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?**

If the Government chooses not to grandfather certain technologies of existing projects under the RO, then it is appropriate to continue with scheduled banding reviews in the line with the current arrangements under the RO, including the provision for an early review if there is sufficient evidence. This would be consistent and continuous with the existing RO arrangements and reassure investors.

Conversely, moving projects unilaterally out of the RO and into the new scheme would undermine investor confidence and could be inequitable, as the projects will have been developed on the basis of the RO. As a result, all existing RO participants should be given the option to remain within the RO.

In our view, the best option for nearly all technologies would be to grandfather their support levels in the vintage RO, based on a final banding review.

The possible exception is co-firing of biomass, as this technology may not warrant retention in the RO right up until the final scheme closure. However, given the timescales for wider deployment of low carbon technologies, it is appropriate that co-firing should continue to be supported until at least 2025.

A CfD for co-firing on electricity price, for a limited duration that can be extended on review, may be more appropriate for co-firing than retention in the RO. If the RO continues with a headroom approach, this would also have the advantage of removing a major source of uncertainty in forecasting ROCs for the headroom calculation.

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**

Our preference is to fix the price of a ROC for existing and new generation. This is the practical intention of the headroom process in any case. The calculation of headroom is already challenging and as the vintage RO is run down, the determination of both targets and/or headroom will become progressively more volatile and complex, for a diminishing quantity of generation. It would be better to make a clear and one-off decision at this time of major change to move to a fixed price ROC.

To avoid hiatus, the fixed ROC should only be introduced from 1 April 2017. This will give sufficient time for a properly considered review to determine the appropriate value.

A concern has been raised that fixing a ROC will trigger a renegotiation of all existing Power Purchase Agreements (PPAs). It is true that, depending on the exact PPA conditions, some may be voided by the introduction of a fixed ROC. The widespread renegotiation of PPAs at the same time is a concern and will need to be addressed. However, it is not a reason to avoid a move to a fixed ROC, which will be a far more robust and enduring solution in the longer term.

It is important to recognise that uncertainty in the headroom calculation creates additional costs for the consumer. Vintaging the RO will remove the need for the recycling element so there is no need for headroom to continue, in which case headroom would present an additional cost for no benefit.

To provide an indication of the scale of impact from variations in headroom, a 1% change in the obligation level in a given compliance period would result in around a £0.40/MWh change in the cost of the RO. As the RO allows suppliers to recover true costs from customers, this would be a £0.40/MWh increase in customer bills with additional uncertainty in future 'non published' supply periods. In future years if the Calculation B, headroom calculation is invoked, the scale of this impact would increase with the obligation increases.

If a customer was on a pass through supply contract, at the end of the period, in the more extreme scenarios they could see a movement of the order of £3/MWh if the initial forecast was based on the fixed target price and then headroom is subsequently invoked later.

Equally for fixed price contracts, suppliers could be bearing this same cost range, particularly if a customer has entered into a contract prior to the October before the start of a compliance period when the obligation level is set. This scale of cash flow uncertainty could significantly impact a number of companies.

Moving to a fixed price ROC would remove these fluctuations and uncertainties. However, in so doing, it is essential that there is a transparent and consultative process for determining the ROC price. This must ensure that a fair value is applied, to maintain investor confidence.

EDF Energy
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