SSE

SSE Electricity Market Reform response

Executive Summary

Ensuring the three key phases of investment are considered

SSE understands the reasons and motivations for Electricity Market Reform and the need to accelerate investment in the electricity sector. In assessing the impacts of reform measures, it is important to reflect on the three distinct phases of investment – development, construction and operation - and to recognise that the main bottlenecks and financing challenges are in development and construction. However, the main focus of EMR has been on operational assets and in particular on price risk. Although it is clearly important that the fundamental economics of operating assets are attractive enough to pull through investment in the earlier phases, and that refinancing will be possible for projects once built, it is essential that any reform does not adversely impact on development and construction and that separate but compatible solutions are found to deal with them.

Avoiding an investment hiatus

The current package of preferred options is unnecessarily complex. Even if it created the optimal enduring conditions for some or all of the technologies, which we believe is questionable, due to its complexity it will take a considerable time to develop and to be explained to, or accepted by, investors. The hiatus in investment in project and supply chain development, which has already started[1], could last until 2014 or beyond which would make the attainment of low carbon, renewable and security of supply targets impossible. This is particularly damaging for the supply chain and inward investment opportunities since many decisions on location will be taken irreversibly in this timescale.

Objections to DECC's preferred package

In addition, DECC's proposals for Contracts for Differences (CfDs) and a targeted capacity intervention would represent a very high level of central control over the electricity market. Very little scope for market decision-making and competitive differentiation would remain whilst policy risk would increase substantially. As a result, the motivation for the private sector to invest, particularly in the development stage of large projects, would be considerably undermined and many of the key benefits of liberalised markets (competitive pressure on costs; innovation; responsiveness to shocks and uncertainty) would be lost. As it stands, the preferred package simply replaces price risk which generators are able to manage and should be exposed to, with new and additional political and regulatory risk which they can not manage and should not be exposed to.

Workable options

However, we do believe that it is possible to make the necessary adjustments to the market in a clearer and simpler fashion using a combination of a general capacity mechanism and a premium FiT building on the basis set by a 'bankable' carbon price support mechanism. If this were combined with an initiative such as the Green Bank providing equity co-investment to support the financing requirements in development and construction, there is a realistic chance that the overall objectives of the EMR can still be met.

The following summarises SSE's views on the four key reform areas.

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[1] For SSE this includes low carbon investments on hold as well as the announcement of the closure of Fife and scaled-back plans for Abernedd gas-power stations (see Press Release on the 8th March).

Carbon Price Support

SSE believes that strengthening the long-term carbon price signal is an important element of EMR. In particular, visibility on the carbon price beyond 2020 is needed, given the uncertainty over the status of the EU ETS after that date, and the timing of large low carbon investments. We believe the UK's primary focus should continue to be on strengthening the EU ETS. If an additional measure is needed such as Carbon Price Support (CPS), HMT and DECC need to ensure that it:

(i) is set to deliver a 'bankable' carbon price trajectory. This means the support should be adjusted so the overall carbon price (EUA and CPS) is never outside a narrow range, and the trajectory needs to be set for a long period in advance. This is similar to the approach suggested by the Prime Minister for the fuel price escalator and moves away from a tax which can be changed every year at the complete discretion of Treasury, which is not a viable basis for investment. In this way, it is vital that HMT finds a method to 'fetter its discretion' on setting the tax levels and the overall trajectory. This could potentially be achieved by using a contractual rather than a fiscal approach;

(ii) increases investment but does not unnecessarily raise customers' bills or distort the market through undue windfall gains and losses to existing generation. Given that little new investment can be induced by the CPS before 2020, up to this point the trajectory should be set to 'guarantee' a gradual trajectory to reach say £25/tonne in 2020, which would be in line with current expectations on EU ETS prices (i.e. the tax will only be activated if EUA prices fall below expected levels). Given that the rest of the EMR package is unlikely to be implemented before 2014, the CPS should also not be activated until this point. In the long-term the trajectory should be based on an assessment of what level of pricing low carbon technologies actually need; and

(iii) does not result in UK carbon prices being substantially higher than prices in mainland Europe. This would place UK generators and major users at a significant cost disadvantage and result in a significant increase in interconnector imports[2].

Providing these conditions are met, SSE believes CPS can help enhance investment and ensure the merit order favours low carbon.

Capacity mechanism

SSE believes a general capacity payment – paid to all capacity according to its overall availability - is needed to secure sufficient capacity going forward. The current market framework is already deficient in rewarding investment in system reliability, as large sections of the market can effectively avoid long-term costs of providing this 'insurance' by contracting on a short-term basis (i.e. there is not a fully developed market for reliability). As the level of inflexible plant on the system increases (i.e. wind and nuclear), these problems will be exacerbated, with thermal plant becoming increasingly reliant on infrequent and uncertain price spikes to pay back investment. Combined with uncertainty around market reform, there are now serious concerns over whether sufficient investment in firm capacity will come forward over the coming decade and many of SSE's current plans for capacity investment are on hold.

Crucially, the mechanism must cover all capacity, including demand side resource. Any mechanism which attempts to pay only a subset of capacity (e.g. only peaking response or new) will simply increase risks for all other types of investment. The 'targeted mechanism' proposal could be highly damaging. With the potential for centrally-tendered plant (and uncertainty around the timing and volume of this), market-based investment would be sterilised. Developers would be concerned that if they did invest this would be 'crowded-out' by tendered plant and hence would hold back investment or may even strategically defer investment in the hope of securing a tender. Tenders of new plant would also force premature closure of existing plant – significantly raising the overall costs of securing an adequate capacity margin. This would all lead to a 'slippery-slope' -

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[2] A carbon price differential of around £5/tonne would encourage significant fuel and carbon leakage (i.e. generating abroad and importing would be cheaper than domestic generation) and a differential of £15-20/tonne would result is major investment leakage to mainland Europe (i.e. it would more cost-effective to build a CCGT abroad with a corresponding interconnector, rather than build a CCGT domestically).

where an increasing amount of plant is tendered for and the role of the market eroded. Tendering for new plant will also deter development expenditure (see next section).

Conversely, a general capacity payment could substantially de-risk investment in capacity, reduce costs of finance and allow the market to bring forward the most cost-effective forms of capacity[3]. Moreover, wholesale energy prices would fall as a higher capacity margin is sustained and capacity costs are recovered through the capacity payment. These factors will largely offset the additional costs of the capacity payments required - which may themselves only represent the equivalent of around £5/MWh. For all these reasons, costs facing the consumer would be limited to what is needed to pay the unavoidable 'insurance premium' that is needed to provide sufficient capacity to balance the system on a daily, monthly and annual basis.

Early clarity of the intention and approach to a general capacity mechanism is needed so informed decisions on supply and demand options needed for the middle of this decade can be made now.

Support for low carbon

The Renewables Obligation (RO) is now a well-designed and well established support mechanism and, as such, SSE does not believe there is a case for reform[4]. The difficulties in the rate of renewables deployment have been related to grid access, transmission charging, planning constraints and financing construction/operational risks (the same issues that will delay nuclear) – not the support mechanism.

It is therefore essential that, should the RO be replaced, it will be 'vintaged' for existing and upcoming investments – however, the period that the RO is open for new investments should be extended until 2020 (and 'vintaged' until 2040), to ensure investments needed to meet 2020 targets are not adversely impacted.

If the RO must be replaced it would be important to keep the new renewables 'in the market', such as through a Premium FIT (a fixed subsidy on top of the electricity price). Taking low carbon generation out of the market through Contracts for Differences (CfDs) would substantially undermine the basis of liberalised markets and could have a number of damaging effects:

- *Loss of competitive pressure*. With contracts for electricity in effect being with, and set by government, the scope for competition in supply and in contracting of energy would be heavily restricted. Moreover, market signals on when, and how much to build would be lost and competitive pressure on the supply chain would be reduced. In particular the ability to generate value through prudent risk management and by selecting the 'right' projects is a fundamental motivation to invest for all developers which would be largely removed with a system of CfDs. Related to this, a key motivation for many investors in low carbon generation is as a hedge against higher than expected carbon or gas prices – this motivation would be also removed through CfDs;
- *Reduced and distorted liquidity*. CfDs would 'crowd-out' liquidity for Suppliers in medium- and long-term markets, since CfD-Generators would no longer have an incentive to enter into such contracts. This would also undermine these markets and create serious difficulties for plant not covered by a CfD, including new conventional and all types of existing generation. Liquidity may be enhanced in the market used to set the reference price (as generators look to match this price) but this will again create a major distortion by displacing trade away from other markets;
- *Limited scope for price discovery*. CfDs inherently require more government involvement in fixing prices, increasing the information requirements for government and the risks of setting the 'wrong' price. In particular, the scope for the market to 'self-correct' for general movements in construction

[3] As an example of this the annual fixed costs of a new OCGT (including interest costs) are roughly £60/per year/kW whereas a life-extension of a mature thermal plant could cost less than half this.
[4] Since its introduction in 2002, the RO has seen the level of renewable electricity from 1.8% to over 6.6%. Over a 1 GW of wind is currently being built every year under the RO and this figure would be substantially higher were it not for planning and grid constraints which will also impact under a FiT or CfD approach.

costs over time would be removed. Therefore under a CfD, developers would require a significant premium to cover this risk, raising costs to consumers;

- *Reduced development capital.* With CfDs, developers would not be in control of the build decision (with this being subject to the successful award of contract) and hence the motivation to invest at the crucial development stage would be substantially undermined. This would be particularly acute if the CfD prices were determined by auction. There is a risk very few parties would be willing to commit the substantial development capital needed to submit sensible bids without any guarantee of contract. Therefore, there may be little competition for contracts. Moreover, successful bids may not be robust and include underestimated costs (so-called 'winner's curse'), and consequently many projects would fail to be delivered (as was the experience with NFFO auctions). This added political and regulatory risk would also be reflected in higher costs of capital for the development phase; and
- *High transaction costs and implementation issues.* CfDs would require substantial contracting, payment and cost-recovery systems which would involve high setup and running costs. Moreover, finding an appropriate price index against which to set the contracts would be challenging and, if costs are recovered through a variable levy on bills, suppliers would face substantial cash-flow risks. The increased complexity implied here would also be a deterrent to new investors on both the generator and supply side. This runs contrary to the desire to introduce a mechanism which avoids the perceived complexities of the RO. These complex implementation issues also raise serious concerns about whether the mechanism can be delivered in a timely manner and thus risks serious delays to investment in project and supply chain development. With the supply chain this may be irretrievable since many decisions on location of inward investments will be taken in the next few years.

Even if CfDs may be seen to be helpful for nuclear development they are particularly unsuited to variable renewables and flexible generation as these technologies would typically earn a price which is substantially different from the average reference price used for the CfDs when they trade in the wholesale market. As a result overall revenues and risk exposure would be difficult to predict, market incentives would be distorted and market-based contracting arrangements (e.g. Power Purchase Agreements) would become very complex. These issues do not apply to nuclear generation given that this is a baseload technology and likely to capture the reference price more consistently. If all low carbon is included, this would create a structural imbalance for renewables and CCS. For this reason a CfD approach should only be considered for nuclear.

In any case, before extending support beyond renewables, SSE believes it is important to first assess the impacts of CPS and a capacity mechanism (once their design has been established) to determine what funding 'gap' remains. Should this remain, explicit and clearly targeted support for nuclear, which keeps it 'in the market', may be needed which will need careful design. The impacts of extending subsidy coverage through a CfD scheme on wholesale markets and dispatch patterns also need to be carefully assessed and managed. The analysis so far has been at too high a level and does not adequately take account of the behavioural and perception issues which always affect markets.

Emissions Performance Standard (EPS)

An EPS on new plant as proposed can provide a useful backstop to prevent build of plant that is inconsistent with climate change goals. SSE agrees that it should be set as an annual limit (to allow build of peaking plant) and that the appropriate level is the equivalent of 450gCO_2/kWh for a plant operating at baseload. The principle of grandfathering this level is extremely important otherwise investment will be heavily deterred. Moreover, any revision of this level should be conditional on successful demonstration of CCS on both gas and coal.

Concluding comments

As a final comment, SSE has concerns that the impacts on wholesale prices of the proposed EMR package have not been given sufficient weight and analysis in the consultation nor have the range of potential unintended consequences been fully explored. For example, a system of CfDs covering all low carbon generation will depress wholesale prices and make them more volatile as well as implying a high level of central control over volume decisions. The implications of this for the rest of the market require very careful analysis[5]. DECC's preferred package arguably represents movement towards a tipping point at which a fully regulated solution becomes inevitable, as very little of generation (and supply) decisions would remain driven by market signals, and these signal themselves would be severely distorted. In turn, this would result in an inefficient, more expensive and less innovative electricity market.

Wider context

It is important to recognise that EMR does not stand in isolation. How the market develops in GB needs to be seen in the context of drivers from Europe – single market, increasing interconnection, Europe wide regulation. Even in the UK, current reviews of the Supply industry, liquidity and transmission charging as well as the ongoing review of Ofgem and other institutions all need to be tied in when assessing the implications and considering the potential for unintended consequences of EMR.

SSE's preferred reform package

The following summarises what SSE believes to be a workable reform package, within the options presented in the consultation, which enhances investment and minimises market distortion:

- Carbon Price Support –setting a 'bankable' carbon price trajectory at very low levels until 2020 when a target price within the range £20-30/tonne should be implemented;
- A general capacity mechanism – covering all 'firm' capacity (and demand-side management);
- Retention and extension of the RO for renewables (and, if any reform is made, a Premium FIT is the best option); and
- An Emissions Performance Standard on new build as proposed.

Due to its relative simplicity, such an approach could be introduced quickly and avoid the delays and costs associated with the preferred measures outlined in the consultation.

About SSE

SSE is a UK-owned FTSE 30 company with over 20,000 employees and a £1.6 billion annual investment programme until 2015. It is the largest renewable generator of electricity in the UK with nearly 2.5GW of capacity, and the second largest generator overall. It supplies over 9.5 million customers with electricity and gas through its Southern Electric, Scottish Hydro, SWALEC and Atlantic brands, and operates electricity and gas networks in the south of England and the north of Scotland. It also has interests in telecoms, water, and contracting services. In electricity generation, aside from major a renewables programme, SSE is also developing a gas CCS project at Peterhead, is in a consortium to develop a nuclear power station at Sellafield and is also developing conventional thermal generation projects.

[redacted]

[5] We note this issue is partly ignored in the Redpoint analysis through the assumption that low carbon generation is paid on the basis of availability rather than energy output.

Answers to consultation questions

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?

Much of the assessment is reasonable however it seriously over-emphasises the importance of price risks (essentially what EMR impacts on) and underemphasises other barriers to investment such as construction risk, planning and grid access. Price risks are only a small contributor to costs of capital for low carbon investments relative to construction, operational and policy risks. Moreover, price risks are something that the market is able to manage effectively (unlike, for example, policy risk). In this way, the potential for EMR to resolve the investment challenge is greatly exaggerated.

The key challenge which is not addressed in the EMR is the availability of funding for development and, particularly, construction. Some form of equity co-investment model through the Green Bank should be considered to deal with these particular challenges.

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

Generally the arguments given suggesting significant risks to security of supply from insufficient capacity are valid. However, some key factors suggesting a general capacity mechanism is needed and desirable are missing from the assessment. SSE would characterise the case for a general capacity mechanism as follows:

- *Under current market arrangements, conventional generators are fully exposed to reductions in demand for their energy.* The recent reduction in demand has reinforced this message. This has resulted in a short-term collapse in the value of generation. This in turn has led to a loss of confidence in the ability of generation investment to deliver adequate returns. This risk is expected to become higher as climate change policies increases the amount of off-market investment in low carbon generation as well as demand reduction; and
- *The lack of a market for reliability.* In general, it is not currently possible to contract for a level of reliability (nor are customers generally exposed to the true value of electricity in real time). This 'public good' characteristic of reliability means it is likely to be undersupplied in an 'energy-only' market.

In the last decade or so, these issues have not been material because (i) the market is still relatively new (it has existed for less than one business cycle), (ii) the market started from a position of surplus generation arising from the previous market structure as well as the long period of nationalisation; and (iii) CCGT investment (driven by cost advantage not just capacity need) could be made easily and quickly and kept capacity margins high. This will not be the case going forwards as a large amount of capacity will be taken off the system over the next decade as a result of the LCPD, IED and nuclear plant closures. On top of this, there are new challenges for investment in capacity:

- *Increased system inflexibility raising risks for conventional thermal plants.* As the amount of wind and nuclear capacity on the system increases, the flexible plant needed to balance the system will operate under lower and more uncertain load factors[6]. As a result, investment in flexible thermal plant (both existing and new) will become more reliant on price spikes. This will make such investment more risky because: (i) the frequency and timing of these price spikes will be uncertain

[6] For example, the recent study by Poyry showed that, under 33 GW of wind in 2020, load factors for 'new CCGTs' will fall to 55% (from around 75% at present) and for 'Old CCGTs' load factors will fall below 5% (from 25%). 'Super-peaking' plants may be used a few hours one year and not at all the next, depending on wind speeds during peak demand periods.

(e.g. in some windy years price spikes may not materialise at all); and (ii) the threat of regulatory intervention creates doubts that the needed wholesale price spikes will be allowed to materialise. Potential policy reforms, such as fixed FITs, could further encourage inflexible running patterns and distort wholesale prices (depressing them overall but making them more volatile), making investment in conventional flexible capacity yet more difficult;

- Financing investment in generation capacity is becoming increasingly challenging as utility balance sheets become more stretched; and
- Regulatory and planning constraints result in much slower deployment timescales, even for CCGT, which reduces our ability to respond quickly enough to signals.

For all these reasons, a general capacity mechanism is required to ensure investment in capacity is sufficiently rewarded and that investment decisions can be made in a manner, and at a time, to ensure an adequate capacity margin is sustained.

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)?

The analysis does not articulate the impact of what is the most significant of the proposed reforms: extending subsidies to all low carbon generation. This is very significant and will have a major impact on wholesale prices and risks facing the residual market, with prices likely to be lower and more volatile. In particular investment in CCGTs will become significantly more risky leading to reduced investment, reduced security of supply and high costs of capital. All of these are costs which do not appear to have been taken into account.

If price risk is simply transferred from generators to consumers the risks and costs are not removed and are simply hidden. However, if it is transferred from those who can manage it to those who can't, then costs will actually increase.

The analysis fails to examine the impact of the measures, either on an enduring basis or in the transition, on overall capital costs (e.g. the overall option of capital needed is likely to be increased through the more interventionist models). Nor does it assess the impact on development and construction risks and costs.

SSE concurs that there are major implementation issues with CfDs (see below).

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

No, Contracts for Differences (CfDs) would substantially undermine the basis of liberalised markets and could have a number of damaging effects:

- *Loss of competitive pressure.* With contracts for electricity in effect being with, and set by government, the scope for competition in supply and in contracting of energy would be heavily restricted. Moreover, market signals on when, and how much to build would be lost and competitive pressure on the supply chain would be reduced. In particular the ability to generate value through prudent risk management and by selecting the 'right' projects is a fundamental motivation to invest for all developers which would be largely removed with a system of CfDs;
- *Reduced and distorted liquidity.* CfDs would 'crowd-out' liquidity in medium- and long-term markets, undermining these markets and creating serious difficulties for plants not covered by a CfD, including conventional and existing generation. Liquidity may be enhanced in the market used to set the reference price (as generators look to match this price) but this will again create a major distortion by displacing trade away from other markets;

- *Limited scope for price discovery.* CfDs inherently require more government involvement in fixing prices, increasing the information requirements for government and the risks of setting the 'wrong' price. In particular, the scope for the market to 'self-correct' for general movements in construction costs over time would be removed. Therefore, under a CfD, developers would require a significant premium to cover this risk, raising costs to consumers;
- *Reduced development capital.* With CfDs, developers would not be in control of the build decision (with this being subject to the successful award of contract) and hence the motivation to invest at this crucial development stage would be substantially reduced. This would be particularly acute if the CfD prices were determined by auction. There is a risk very few parties would be willing to commit the substantial development capital needed to submit sensible bids without any guarantee of contract. Therefore, there may be little competition for contracts. Moreover, successful bids may not be robust and include underestimated costs (so-called 'winner's curse'), and consequently many projects would fail to be delivered (as was the experience with NFFO auctions); and
- *High transaction costs and implementation issues.* CfDs would require substantial contracting, payment and cost-recovery systems which would involve high setup and running costs. Moreover, finding an appropriate price index against which to set the contracts would be challenging and, if costs are recovered through a variable levy on bills, suppliers would face substantial cash-flow risks. The increased complexity implied here would also be a deterrent to new investors on both the generator and supply side. This runs contrary to the desire to introduce a mechanism which avoids the perceived complexities with the RO.

CfDs are particularly unsuited to renewables and flexible generation as these technologies would not systematically capture the reference prices used for the CfDs when they trade in the wholesale market. As a result revenues would be difficult to predict, market incentives distorted and contracting arrangements (e.g. Power Purchase Agreements) would become very complex (See Question 9). These issues are less extreme for Nuclear given that this is a baseload technology and likely to capture the reference price more consistently.

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?

It is questionable whether price risk, which generators can and should manage should be removed and replaced with political and regulatory risk which they can not, especially when the price risk is being transferred to a party less well, or not able to manage it.

Transferring (long-term) electricity price risk away from generators fundamentally undermines the basis of liberalised markets. The market would no longer have any role in decisions on how much and when to build. With the market being essentially planned, the cost of this transfer therefore manifests itself in inefficient central decisions and higher overall costs of generation which ultimately increase costs to the consumer. On top of this CfDs would also remove the incentives for electricity consumers to respond to the underlying long-term drivers of electricity prices (for example, reducing consumption at times when carbon and fuel prices are high).

More specifically, CfDs will crowd-out medium- and long-term wholesale markets, undermining liquidity reducing the scope of the market to signal investment and to manage risks itself. For plant not covered by the CfDs, this will be a particularly acute issue as the market will not only be less liquid but also more volatile (for example, in low price years the effective subsidy is higher. This has the effect of pushing prices yet lower thus amplifying price movements).

It is also important to note that CfDs are not likely to be appropriate for fuelled plant such as CCS and biomass. For example, because fuel prices have a major impact on electricity price, CfDs are less useful for CCS. As gas (and electricity) prices rise, the subsidy payment will fall away potentially making the running of plants uneconomic. This effect could be partially mitigated through long-term gas contracts or linking CfDs to a fuel price index. However, this would add substantial complexity to the contract and for technologies such as biomass where price indices are not available this would be difficult to achieve.

The complexity of CfDs would also be a major disadvantage and deterrent to investors – particularly given that different types of CfD would be needed for different technology types. With Government as the counterparty for the CfDs, and the need for a complex payment (and cost-recovery) systems, the level of regulatory and policy risk would be high and far outweigh any benefits from risk transfer.

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?

Long-term price exposure provides incentives to build the right volumes at the right times and also provides incentives for consumers to reduce demand in periods of higher prices (See Question 5). Medium and short-term price signals provide important incentives to develop a diverse generation mix which is available and dispatched at the right times such that load requirements are met efficiently.

A CfD system would not simply long-term remove price risk from generators, much of this risk will be transferred to the residual market in the form of more volatile prices and to the consumer who will be taking on the risk of the 'wrong' price being set and of over- or under-build. For plants built without a CfD (e.g. CCGT) there would be a major concern that they will be crowded-out by plant sheltered from market signals through a CfD (in particular, nuclear).

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 hurdle rate reductions estimated in Table 4 are unrealistically high and are unlikely to be realised for a number of reasons:

- Long-term price risk is only a small element of the total risk premium for low carbon generation projects. Other factors such as construction and technology risk are far more significant in raising/setting the cost of capital. Moreover, price capture and balancing risk remains with generators under CfDs (NB. This is not to say generators should not face this risk).
- The increased perception of policy risk from major policy reform which is difficult and complex to implement will raise required hurdle rates;
- Even if risk facing generators is lowered, some of this benefit would be 'leaked' to financiers as they take their margin. Experience with PFI contracts suggests large margins can be taken by lenders in situations where government is attempting to provide a long-term contract.

On top of this it is important to stress that price risks are not removed, they are simply transferred to consumers and to the residual market.

More specifically, it is unclear why the estimated hurdle rate reductions are higher for Offshore Wind than Onshore Wind in Table 4. In fact, the opposite is true as a higher proportion of revenue for Offshore Wind comes from the subsidy and therefore removing long-term price risk would have a less significant impact on overall revenue risk.

The estimates for the impacts of CfDs also fail to reflect the increased complexity of the mechanism and the higher inherent policy risk both of which will increase the required hurdle rate. Moreover, they do not reflect the fact that generators are still exposed to balancing and price capture risks (although, for clarity we note that generators should be exposed to such risks to promote efficient dispatch, siting and availability decisions).

All these issues put into serious question the basis for the hurdle rate estimates. These also appear to have been made on the basis of a theoretical exercise rather than on practical market understanding. As a result the benefits arising from reducing market price exposure have been significantly overestimated.

As a final comment it is should also be noted that the preferred intervention on security of supply, the targeted capacity mechanism, will considerably increase risk for investors in capacity who would face the risk of being 'crowded-out' by tendered plant (see Question 20). In this way, this intervention is inconsistent with what government is attempting to achieve with CfDs.

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?;

Even if the proposals were to make more (debt) finance available to refinance operating assets, we would not expect any increase in the availability of finance for development or construction (this will remain constrained due to a number of separate factors such as construction risk) and there is a high risk that development capital will exit the sector as the ability to create value through prudent risk management and by selecting the 'right' projects is removed. As regards enhancing availability of finance, initiatives such as the Green Bank on the basis of equity con-investment, which could directly address construction risk, are far more important.

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?

For all types of generators, the unfamiliarity and complexity of the CfD model would be a deterrent to investment, particularly those how have become comfortable with the RO through experience. The Premium FIT, given its close similarly to the RO and simplicity, would not create such an adjustment problem.

Under CfDs the crowding out of medium- and long-term wholesale markets is likely to create significant difficulties for existing and future generators not covered by the CfD system, particularly conventional thermal stations such as CCGTs.

For many utilities (both existing and new entrants) and equity investors the removal of 'upside' to investment through a CfD would reduce the attractiveness of investment. Under a Premium FIT investments would remain attractive to such investors.

The uncertainties and delays of the more complex and less well understood preferred options will have a disproportional impact on new entrants and independent generators, particularly those who are dependent on third party finance.

Finally, under CfDs contractual arrangements would become significantly more complex. In particular, it is highly likely that under a CfD, the provision of annual price setting for PPA contracts would end and complex contractual arrangements would be needed to allow PPAs to transfer balancing risk but not medium- and long-term price risk (which is would be covered by the CfD). It is not clear how this would be achieved.

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?

Liquidity in the market used to set the reference price is very important in ensuring CfDs can operate. The N2EX market, where traded volumes are growing, may be the only trusted and robust reference to deliver this.

However, it is not at all clear what the most appropriate market could be to calculate a reference price in general terms. For example, the markets which are most liquid (e.g. day ahead markets) are not necessarily the markets in which wind generators are best able to use to trade their energy given the uncertainties involved in forecasting wind. The choice of reference price and the period over which this price is calculated will have major impacts on the risks facing generators and the how they trade their power. However, these impacts are not easy to predict and will be opaque from an investment perspective.

It should also be noted that the introduction of the CfD system itself would also have impacts on liquidity. In the short term, liquidity may be enhanced as generators look to ensure they can match the reference price. However, in the medium- and longer-term liquidity will be reduced, since the CfD is providing a long-term price hedge thus crowding out the role of the private market.

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

SSE does have significant concerns about wholesale market distortion from having all low carbon being rewarded through an output-based subsidy which will encourage inflexible running patterns and depress prices. This distortion could be major in the future as all low carbon generation is subsidised to generate.

In this sense, having payments based on availability may be less distorting to dispatch patterns and encourage more flexibility. However, paying on the basis of availability also has unintended consequences as it will not encourage build of high efficiency plant (although the wholesale market should still provide some incentive here). Designing an availability payment would also be complex given that load factors vary across and within technologies.

For these reasons, although it has its drawbacks, we believe output-based subsidies are the simplest approach and the least distorting to incentives. It should also be noted that the issues with wholesale maket distortion could be offset partially, for 'firm' generators through a general capacity mechanism.

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?

Yes.

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?

Option 2 is most appropriate: it allows crucial new CCGT build, without which security of supply would be seriously undermined. At the same time, it ensures that any new coal build does not result in higher emissions than that resulting from a CCGT.

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, this is very important. Without grandfathering, the investment risk of having an unfunded and unquantified future CCS liability would be unmanageable.

It is generally not for Government to decide the economic life of a power station, this is a commercial decision and the grandfathering should cover this entire period. Without this assurance, an investment in a new CCGT would be extremely risky.

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?

Two key principles should be used to define when a life extension should be subject to an EPS:

i) the upgrade/life extension should only be subject to an EPS if it represents a major investment in the plant, of the same order of magnitude as an investment in a new plant.

ii) the qualifying definition is simple, transparent and easy to verify for both Government and market players.

Any ambiguity about the definition used would significantly deter investment (for example, because investors in new capacity must make careful judgements about when other plants are going to come off the system in making a decision).

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

The reviews should not be able to retrospectively change the principle of grandfathering and any changes need to be made objectively based on very well-specified criteria around the status of CCS technology and the funding available for this.

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

Ideally biomass should be treated on the basis of life-cycle emissions of the fuel used but a 'zero-rating' approach may be more pragmatic in the short-term whilst accurate methodologies for assessing these are established. It should also be noted that biomass fuels will need to meet a minimum greenhouse-gas (GHG) saving requirement in order to qualify for support under the RO.

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

No, making exemptions (or even the possibility of exemptions) will create major investment uncertainties and 'stranded asset' issues for investors who must take decisions on the basis of an EPS being in place. The possibility of exemptions may encourage developers to hold back investments in the hope of securing an exemption which would undermine the other parts of EMR. Moreover, so long as the EPS is an annual limit, new investment in relatively carbon-intense capacity would not be prevented so long as this is run at low load factors.

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?

SSE broadly agrees but the negative impacts and unintended consequences of targeted mechanism have been seriously understated. Moreover, the benefits of a general capacity payment in reducing investment risks and bringing forward sufficient capacity have been understated (see Question 20). It is also not true that a capacity mechanism necessitates a return to a 'pool' system. It is perfectly possible to introduce a payment under the BETTA system. Payments could be made in the bilateral market based on generators' availability as measured by their 'Maximum Export Limit'[7] declarations. This is subject to a Good Industry Practices test under the existing codes and the System Operator has powers to scrutinise declarations and taken remedial actions when there are significant compliance issues.

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

SSE believes a general capacity payment is needed to secure sufficient capacity going forward. The current market framework is already deficient in rewarding investment in medium- and long-term system reliability, as large sections of the market can effectively avoid long-term costs of providing this 'insurance' by contracting on a short-term basis (i.e. there is not a fully developed market for reliability). As the level of inflexible plant on the system increases (i.e. wind and nuclear), these problems will be exacerbated, with the residual thermal plant becoming increasingly reliant on infrequent and uncertain price spikes to pay back investment. Combined with uncertainty around market reform, there are now serious concerns over whether sufficient investment in firm capacity will come forward over the coming decade.

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[7] "Maximum Export Limit" is the profile of the maximum level at which the generating unit may be exporting (in MW).

Crucially, the mechanism must cover all capacity, including demand side resource. Any mechanism which attempts to pay only a subset of capacity (e.g. only peaking or new) will simply increase risks for all other types of investment. The 'targeted mechanism' proposal could be highly damaging. With the potential for significant volumes of centrally-tendered plant (and uncertainty around the timing and volume of this) market-based investment would be sterilised. Developers would be concerned that if they did invest this would be 'crowded-out' by tendered plant and hence would hold back investment or may even strategically defer investment in the hope of securing a tender. Tenders of new plant would also force premature closure of existing plant – raising the overall costs of securing an adequate capacity margin. This would all lead to a 'slippery-slope' - where an increasing amount of plant is tendered for and the role of the market eroded.

Conversely, a general capacity payment could substantially de-risk investment in capacity, reduce costs of finance and bring forward the most cost-effective forms of capacity. Therefore, costs facing the consumer would be limited to what is needed to pay the unavoidable 'insurance premium' that is needed to provide sufficient capacity to balance the system on a daily, monthly and annual basis.

The response to Question 22 details the efficiency advantages of a general capacity mechanism compared with a targeted mechanism.

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

Prices in the wholesale market would move closer to marginal costs and be depressed, especially if the capacity is used on the basis of economic dispatch. This would exacerbate a major 'missing money' problem for non-tendered plant. Even if tendered plant is dispatched on the basis of 'last resort' this still creates a great deal of risk around whether the rules here will be changed (and the political pressure to do so will be high if price are high in a given period).

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

- **a central body holding the responsibility;**

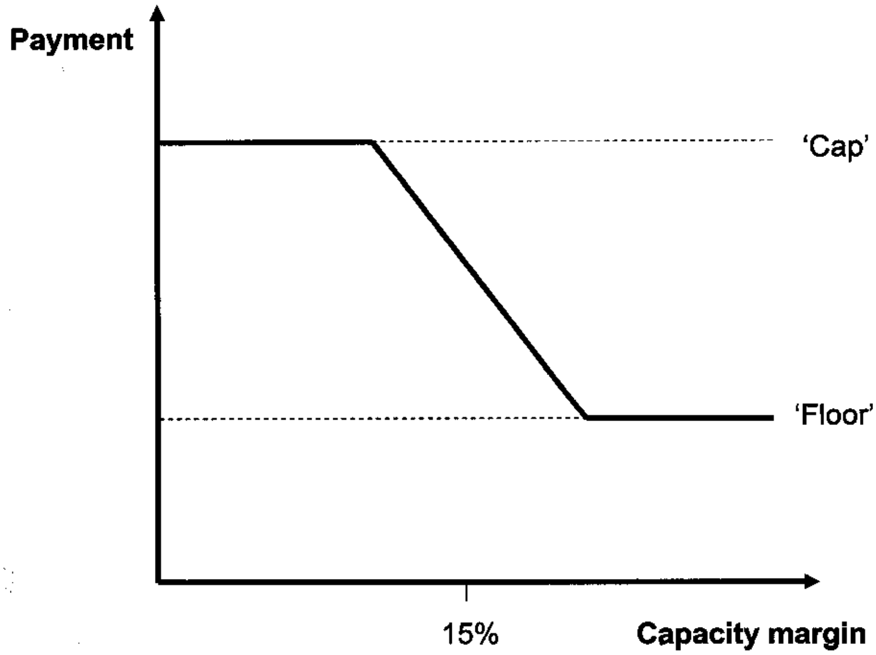
  A central body must be responsible for defining the key parameters of any capacity mechanism (e.g. defining the target capacity margin and the basis for calculating the payment). An organisation with expertise in energy trading such as Elexon is likely to be most appropriate for administering payments.

- **volume based, not price based; and**

  A price-based mechanism is preferable for investors as this would be likely to be less volatile whereas a volume-based mechanism provides more certainty of outcome (i.e. capacity delivered).

  In practice most capacity mechanisms have elements of price and volume setting. For example, caps and floors in a capacity market, or making an administered price responsive to the size of the capacity margin (or probability of lost-load).

  SSE's preference is for a capacity payment with some responsiveness to 'market tightness' (i.e. the payment rises if the system becomes short). To provide a basis for investment a floor on this payment may also be valuable although this would need to be carefully set to avoid encouraging overbuild. The figure below provides an illustration of a capacity payment where the capacity payment calculated has some responsiveness to market conditions within a 'cap' and 'floor'.



- **a targeted mechanism, rather than market-wide.**

No (see above). For the reasons set out in the consultation, a targeted mechanism will always 'evolve' into a general one, ultimately at greater cost to the consumer. A market-wide, general mechanism would be more effective in delivering an adequate system margin for the following reasons:

- **Encouraging cost effective capacity choices** (e.g. life extensions where this is cheaper than new build). Under the targeted mechanism government must contract for new plant. However, new plant is not the most cost-effective form of capacity. The lowest-cost form of new capacity is an open-cycle gas turbine (OCGT) which costs approximately £60/kW/year to maintain on the system (including annual financing and fixed operating cost) whereas life extension of an existing CCGT plant (which is likely to be up to 20% more fuel efficient) can cost less than half of this. A general mechanism would encourage such cost-effective decisions and thus ensure the most cost-effective capacity mix is brought forward,
- **Lower cost of capital** for new capacity resulting from reduced reliance on uncertain price spikes to reward capacity and a relatively stable revenue stream for capacity. The Redpoint analysis suggests a reduction in the hurdle rate for a new CCGT of 0.3% compared to the status quo. Conversely, a targeted mechanism would create significant investment risks around new CCGT build (e.g. uncertainty around the extent to which the plant will be crowded out by tendered plant) potentially increasing hurdle rates by at least 1% (or deterring build completely). Building 15-20 GW of new CCGT could represent total capital expenditure of up to £10 billion by 2020 and therefore a targeted mechanism could represent additional financing costs of around £100m a year compared to a general, market-wide mechanism.
- **Lower wholesale energy prices** resulting from a higher and more stable capacity margin. A general mechanism will be more effective in sustaining a capacity margin as there would be more certainty over revenues (and, unlike with a targeted mechanism, no requirement to second-guess how much capacity government will contract for). A sustained capacity margin through capacity payments would allow wholesale energy prices to fall closer to marginal costs of generation (potentially up to £5/MWh).
- **The challenge for a capacity mechanism goes well beyond the need to provide peaking** capacity – it will have to provide the mid-merit and baseload capacity to deal with week- and month-

ahead balancing issues (such as a fortnight of anticyclonic weather in the middle of Winter when demand is highest, particularly as more and more heat is decarbonised by switching to electricity).

It should also be stressed that the level of general capacity payments needed to address the 'missing money' is not large. We estimate payments of equivalent to approximately £3-£5 MWh are needed. The above efficiencies will offset these costs as well as providing greater insurance to consumers, with greater assurance over capacity adequacy and less volatile prices.

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?

There should be a strong market for these under both the status quo and preferred package. Including the demand-side in capacity mechanisms is challenging but it is very important to do so and this has been achieved relatively successfully in the USA.

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

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

Economic dispatch would be extremely undesirable and could effectively mean the end of the market as no (very little) new capacity would be build outside of tenders given the impacts on wholesale price.

Last resort dispatch is not only inefficient (i.e. new plant could be commissioned which remains largely redundant) but also creates major policy risks for investors. Market-led investment will be deterred because of the risk that the rules will change and the 'last-resort' plant will be allowed to operate in the market (e.g. if for a period prices are high and there is political pressure to release additional capacity).

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

The BETTA market already includes locational transmission charging which disproportionately penalises generators in Scotland. Locational capacity payments would be double-counting and exacerbate an already distorted signal.

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?

No. The current package of preferred options is unnecessarily complex. Even if it created the optimal enduring conditions for some or all of the technologies, which we believe is questionable, due to its complexity it will take a considerable time to develop and to be explained to, or accepted by, investors. The hiatus in investment in project and supply chain development, which has already started[8], could last until 2014 or beyond which would make the attainment of low carbon, renewable and security of supply targets impossible.

In addition, DECC's proposals for Contracts for Differences (CfDs) and a targeted capacity intervention would represent a very high level of central control over the electricity market. Very little scope for market decision-making and competitive differentiation would remain whilst policy risk would increase substantially.

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[8] For SSE this includes low carbon investments on hold as well as the announcement of the closure of Fife and scaled-back plans for Abernedd gas-power stations (see Press Release on the 8th March).

As a result, the motivation for the private sector to invest, particularly in the development stage of large projects, would be considerably undermined and many of the key benefits of liberalised markets (competitive pressure on costs; innovation; responsiveness to shocks and uncertainty) would be lost. As it stands, the preferred package simply replaces price risk which generators are able to manage and should be exposed to, with new and additional political and regulatory risk which they can not manage and should not be exposed to.

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

We believe a workable package is as follows:

- Carbon Price Support –setting a 'bankable' carbon price trajectory at very low levels until 2020 when a target price within the range £20-30/tonne should be implemented;
- A general capacity mechanism – covering all 'firm' capacity (and demand-side management);
- Retention and extension of the RO for renewables (and, if any reform is made, a Premium FIT is the best option); and
- An Emissions Performance Standard on new build as proposed.

Due to its relative simplicity, such an approach could be introduced quickly and avoid the delays and costs associated with the preferred measures outlined in the consultation.

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

The EMR package must be seen in the context of other major reforms which could have a larger impact on investment. For example, the level and volatility of transmission charging remains a major deterrent to investment which could unwind any gains from EMR.

The implications of market reform for EU harmonisation and liberalisation also merit more detailed consideration.

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

The combination of CfDs for all low carbon generation and a targeted capacity mechanism may in effect represent the end of liberalised markets and a return to a single buyer model. Only a small amount of the market would remain. The risks for market-led investment as it is crowded out by the low carbon and peaking plant contracted for by government would then be so large as to be unmanageable. This arguably represents movement towards a tipping point at which a fully regulated solution becomes inevitable.

Implementation Issues

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

The package involves a high level of central government control, requiring a step-change in institutional knowledge and remit. The key implementation risks relate to establishing a system of CfDs, the complexity of these and the time that would be needed to deliver these, including:

- **Designing and letting contracts**. CfDs will require complex design and letting arrangements as well as a high degree of legal input and due diligence, particularly given that different technologies would require different contract structures. The Non-Fossil Purchasing Agency (NFPA) has some experience in dealing with these types of issues but elsewhere there is very little accumulated institutional knowledge and therefore there is a strong chance that CfDs would not be delivered effectively or quickly.

- **Administering complex payment systems**. Calculating reference prices and arranging the variable payments to CfD holders would also require very complex systems and institutional arrangements. Moreover, if the costs of the CfD are recovered from a supplier levy this will be very complex and uncertain for suppliers. For example, the size of the pot required to make CfD payments would be a function of the MWh of low carbon generation volume and the average electricity price (reference price), both of which will not be known until after the end of the relevant period. Government would need to set a premium level for a year, this will inevitably be set at an incorrect level, therefore a correction would need to be applied in the following year. The combined effect of errors and corrections could result in a volatile and inappropriate charges being applied to customer bills. Suppliers would also be incentivised to predict the errors and charges to smooth customer bills, but this would distort price competition and negate the objective of the government setting a fixed premium.
- **Cost.** There is likely to be significant direct cost impact of any delay resulting from the implementation of a complicated CfD solution, both in terms of the projects affected and the loss of supply chain investment. There is also a potential cost if delay leads to the UK missing legally binding targets which are already incredibly challenging.

Simpler packages, such as a system of Premium FITs would involve significantly lower implementation risks. Premium FITs would require similar systems and skills to those needed for administering the RO and therefore we would expect these could be undertaken through DECC and Ofgem with relative ease.

Question 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?

Under auctions, very few parties would be willing to commit the substantial development capital needed to submit sensible bids without any guarantee of contract. Therefore, there may be little competition for contracts. Moreover, successful bids may not be robust and include underestimated costs (so-called 'winner's curse'), and consequently many projects would fail to be delivered (as was the experience with NFFO auctions where only one quarter of awarded contracts were actually delivered).

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

At present, whilst many low carbon technologies such as Offshore Wind and CCS are immature, a technology specific approach to setting levels is appropriate and should bring forward a portfolio of low carbon generation options. In the longer term, a return to the principles of banding as a reflection of commercial readiness will allow a competitive pressure to be maintained which will be necessary to drive innovation and cost reduction. Beyond that, sometime in the 2020s, a technology-neutral approach will be needed to ensure decarbonisation of the sector is delivered at least cost.

• Should prices be set for individual projects or for technologies

Prices should not be set for individual projects as this would remove all incentives to deliver a project cost-efficiently (e.g. site choice and project design). Price setting for individual projects would allow high cost, inefficient projects to go ahead and involve a high level of intervention and complexity.

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

Given the high development costs needed to submit a robust bid it is unlikely that sufficient competition will come forward. Moreover, those that win may simply be those that do not have robust and realistic bids and projects will not be delivered (e.g. NFFO). It is also important to note that competition in the supply chain is as, if not more important, as competition amongst developers in delivering value to the consumer.

• **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?**

It is not possible for government to decide how much is an 'unsustainable' level of deployment, This drives at a fundamental difficulty with CfDs – the volume of low carbon generation would now be completely government determined, completely removing the scope for private decision-making on the appropriate plant mix.

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

Clearly there will be increased levels of policy risks associated with these reforms. Therefore changes to institutional arrangements which reduce levels of political discretion and protect investments if policies change need to be explored. See Question 30 for other institutional issues.

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

It is not possible to adequately mitigate the adverse consequences of CfDs and a targeted capacity mechanism. These policies simply should not be implemented.

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

A system of CfDs would be extremely complex to implement and therefore the risk of delay is high. In particular, unless the RO is extended to 2020, there would be a major risk of missing the renewables target.

Question 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?

It is essential that, should the RO be replaced, it will be 'vintaged' for existing and upcoming investments – however, the period that the RO is open for new investments should be extended until 2020 (and 'vintaged' until 2040), to ensure investments needed to meet 2020 targets are not adversely impacted. This is particularly important for investors reaching financial close around 2013/2014, who may be uncertain about signing up to a new mechanism where there is no guarantee they will be able to accredit under the RO before 2017. The deadline should be judged on the basis that a project accrediting by March 2017 will, in all reality, have to be constructed by the Autumn of 2016 since no significant progress will be possible in the Winter.

It would be much easier and quicker to evolve the RO into a premium FiT and there would be little difference between the vintaged RO and the new premium FiT.

Question 36: We propose that accreditation under the RO would remain open until 31 March 2017. The Government's ambition is to introduce the new FIT 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.**

It is important that generators have the choice of mechanism, particularly if the CfDs option is pursued where there is a very high risk that the policy will be unworkable. If the CfD option is pursued, the RO should be extended to 2020 to ensure that key investments planned for the end of the decade are not adversely affected (this problem is particularly acute if CfDs can only be signed at financial close).

Question 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?**

Scheduled banding reviews as part of the new tariff setting scheme would represent the simplest and most efficient approach.

Question 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**

'Headroom' or the 'fixing the ROC price' represent the most appropriate methods for calculating the Obligation post-2017. Investors are comfortable with the concept of 'headroom' and this represents the methodology likely to be least disruptive (in particular, it would not trigger 'change of circumstances' clauses under PPAs). The 'fixed ROC' may provide a small amount of additional certainty for generators in the long-term if generation volumes become difficult to predict, however this option is more complex with respect to establishing the cost recovery mechanism and calculating the levy on supplier (NB. As with 'headroom' it also still requires prediction of generation in order to calculate a levy on suppliers).