SCOTTISHPOWER

CONSULTATION RESPONSE – ELECTRICITY MARKET REFORM

Introduction

ScottishPower is a major UK energy company with networks, generation and retail interests. It is part of the Iberdrola group, a major international utility and the world's leading renewables developer.

Iberdrola is the majority owner of ScottishPower Renewables – the UK's leading wind power developer – and is part of a joint venture with a view to developing up to 3.6GW of new nuclear power on land adjacent to Sellafield. Our group is therefore a major player in the electricity market reform process and the drive to a low carbon electricity sector.

This response is on behalf of all Iberdrola's interests in the UK and references to "ScottishPower", "we" etc. should be read accordingly.

Current Market Arrangements

1. Do you agree with the Government's assessment of the ability of the current market to support the investment in low-carbon generation needed to meet environmental targets?

The Government's consultation rightly stresses the benefits that the UK has achieved through the development of open energy markets. These have led to competitive prices, low costs and an excellent performance in cutting carbon. We agree with the general position that markets are the most efficient mechanism to reward investment and allocate resources and we applaud the progress the UK has made in taking forward a market led approach and the results it has achieved.

In broad terms, we agree with the Government's diagnosis of the problem. Given a policy requirement for rapid decarbonisation of the domestic power sector, including a large scale deployment of renewables, well designed interventions, which preserve the market led approach to the greatest extent possible, are likely to be necessary to create a framework in which these changes can happen. We also agree that the rapid deployment of low carbon generation, much of which will be intermittent, is likely to interfere with the energy-only market's ability to achieve security of supply naturally, therefore requiring new measures to guarantee supplies. Security of supply is in any event facing a huge challenge with the closure of many older coal plants over the next 10-15 years, as well as the existing oil stations and some nuclear units. This risk would be exacerbated if policy interventions force this plant to close earlier.

It is essential in making these changes to keep focussed on maximising the role of the market. History tells us that state control of industrial activity, embarked on with the best intentions, often produces the worst results. It will be important that interventions are undertaken with care, recognising the risks of unintended consequences. These could arise in both the wholesale and retail markets as a result of high levels of plant earning essentially regulated returns. In taking forward the interventions needed for decarbonisation, a strong market role will help deliver optimum solutions with dynamic as well as static efficiency.

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

The rapid expansion of renewables and nuclear in response to Government policy will tend to make load factors for conventional plant lower and less predictable. This will interfere with the natural ability of an energy-only market to balance supply and demand and put existing plants, which currently guarantee security of supply, at risk of premature closure. In addition to the large scale closures that must happen between now and 2015 under the LCPD, some 20 GW of coal, old gas and nuclear plant may close in the following 10 years. This is a huge loss of firm capacity which will require strong action to avoid the risk of significant shortfalls, especially during periods when there is little wind. In consequence, despite our normal preference for energy-only markets, it is clear that a well designed capacity mechanism will be needed in GB in order to ensure that there is sufficient backup, especially given the low level of interconnection capacity.

It is important to be clear where the security of supply problem is likely to arise. The consultation paper suggests that a key concern is the very short term ramp rate, caused by sudden or unexpected changes in wind velocity. However the attached analysis by Nera suggests that this should be manageable with typical thermal plant, especially when supported by demand side actions. The more difficult problem is likely to be the need for large amounts of power during sustained periods, such as calm intervals in winter where low temperatures and low wind generation can coincide for up to a fortnight – well beyond the time horizon of currently envisaged demand side options. This will need substantial generation assets – it is unlikely that a few new open cycle gas turbines will be a sufficient and effective solution in such cases.

We have identified three risks that may vary the intensity of this issue:

- There is risk <u>around the level of closures up to 2023</u> due to decisions that operators will make in regard to the Industrial Emissions Directive deadline in 2014 to indicate whether to opt for limited life derogation and close. This is influenced by a range of factors, including the outcome of the EMR itself and other policy measures such as Transmission charging (currently the subject of TransmiT). High levels of carbon floor price would exacerbate this risk. There are also unknowns around the level of nuclear life extension.

- There is a risk that <u>investment in new plant is not as forthcoming</u> as anticipated – either as a result of planning delays, lack of infrastructure connection or due to investor risk appetite following finalisation of EMR proposals. EMR must deliver a solution that overcomes any hiatus it will inevitably create.

- There is a risk around <u>demand levels for electricity.</u> – it is possible that anticipated demand reductions do not materialise or that new electricity applications (including electric vehicles, heat pumps, etc) are deployed much earlier than forecast. The forecast level of success of demand side management including smart metering becomes a key factor in any outlook.

These risks increase the need to ensure capacity is available in the next two decades to guarantee supply security. In responding to them, it will also be necessary to be aware of a fourth risk. That risk is that the market interventions themselves are perceived as creating a level of political risk which discourages investors, especially in the flexible plant which must provide security of supply. Great care will be needed to avoid this risk.

Options for Decarbonisation – Feed In Tariffs

Q3. Do you agree with the Government's assessment of the pros and cons of each of the models of FIT?

The Government is correct in its assessment that the current regulatory and market arrangements will not bring forward investment in new nuclear or new coal plant with CCS. In our response to the consultation on the carbon price floor, we argued that that mechanism, applied in the UK alone, would be likely to be ineffective in bringing forward additional low carbon generation; would be detrimental to supply security; and would be highly expensive. We also expressed concerns that much of the benefit would go to existing, rather than new, low-carbon plant. A better result for consumers would be achieved by a mechanism that facilitated new investment in the various low carbon technologies in a manner suited to their needs. For this reason, we think that the Government is right to identify varieties of feed in tariff as the principal strategic option to deliver the desired result.

Looking at the three broad models set out by the Government, we would observe that:

- A *Premium FIT* is the least radical change from the existing Renewables Obligation (RO) which has worked well and is delivering for renewables. But we do recognise that setting a fixed level of premium for technologies whose costs are not materially affected by fossil fuels (including wind and nuclear) requires making an estimate of future power (and therefore fossil fuel and carbon) prices. This is difficult to do with any precision, especially over the long term; and the closer a technology's costs are to market levels – and therefore the larger proportion of total income comes from power sales – the more this uncertainty matters. This issue is manageable for wind under the RO, but a fixed premium appears to be very challenging for nuclear.

- A *Fixed FIT* has been used in many jurisdictions and Iberdrola has invested in renewables under this mechanism. It insulates the generator fully from market issues. This is helpful to the generator in that it reduces risks, but only by isolating the generator from the signals needed to secure the economic dispatch of plant in the market. At the levels of intermittent and baseload low carbon generation that are being considered, we think that a fixed FIT regime could cause significant system operation issues. We think that, to the extent practicable, all but the smallest plant in the UK market should be incentivised to play its part in balancing the system. The fact that much of the plant on the system would be receiving fixed regulated returns could also adversely affect the dynamics of the retail market.

- A *FIT with Contract for Difference (FIT with CFD)* is the Government's proposal to get the best of both worlds, by combining exposure of the generator to the short term market with protection of the generator against longer term movements in average power prices. It is intended to eliminate the market price risk from low-carbon investment decisions while keeping the plant in the market. The contractual approach could allow a number of other issues arising from the decarbonisation agenda to be addressed and is robust against subsequent policy change. However, FIT with CFD is a highly complex approach involving a very high level of Government intervention in the market and looking a bit like a Single Buyer. Much work is still needed to establish how FIT with CFD would work and whether there are unintended consequences to avoid (including in relation to liquidity, the retail market and Government accounts). It would also be necessary to establish how this approach would fit with the EU's vision and rules for electricity markets. We could not endorse the FIT with CFD approach with any confidence until this work has been completed.

In the light of these considerations, we have looked at a fourth variant – a Premium FIT with cap and collar (or, for short, a "Variable PFIT"). It is possible that this approach might achieve substantially the same economic results as the FIT with CFD, but with less complexity and Government intervention, and with a greater role for the market. In broad terms, a Variable PFIT would pay a fixed premium in normal conditions, but if the year-ahead wholesale price rose above a determined threshold, the premium would taper, eventually to zero (leaving the plant supported by the wholesale price alone). Conversely, if the wholesale price were to fall below a lower threshold, the premium would be increased up to a maximum value. This achieves similar risk mitigation to the CFD approach, both for the consumer and the generator, while maximising the role of market mechanisms. A similar idea emerged a few years ago in the context of wholesale price adjustment mechanisms for the RO, but it was incompatible with RO banding and grandfathering, which led to the initial emergence of the CFD concept. These incompatibilities do not arise in a FIT context.

Renewable generation already has a successful long term incentive mechanism in the Renewables Obligation (RO), which industry understands and where risks are understood and managed by the investment community. A new FIT system will therefore need to be at least as attractive to investors as the RO in order to accelerate new low carbon investment - any additional complications will risk reducing that attraction.

Where the design of the FIT transfers some or all long term electricity price risk to customers, it should be easier to set the level of the FIT because of the lesser uncertainty. However, it is unclear to us that this results in any direct reduction in the cost of capital (which is largely influenced by construction and other risks). For technologies such as nuclear, where potential variations in the market price could affect a high percentage of the total remuneration, we think it would be very difficult to proceed with a system that did not offset some or all market price risk, but we doubt that this factor can be usefully expressed in terms of changes to the cost of capital. In short, we think that systems which wholly or partly relieve market price risk will not cut costs directly, but will help insulate both consumers and developers from the consequences of inaccurate estimates of future prices.

Q4. Do you agree with the Government's preferred policy of introducing a contract for difference based FIT (FIT with CFD)?

We think that a Variable PFIT approach (see answer to Question 3) might have some advantages over the FIT with CFD. In particular, it might avoid:

- the need for a large part of the electricity in the market to be traded under state direction, including any associated balance sheet issues for Government;
- the need to set a fixed price for low carbon investments; such decisions can, within a reasonable band, be left to the market;
- complexities around the contracts themselves, settlement and counterparties and interaction with EU directives;
- changes to the nature of the retail market caused by much of the energy portfolio being essentially on regulated prices; and
- some of the discomfort which a number of existing generators (especially smaller ones) have with the CFD proposal.

The Variable PFIT approach does however have its own issues, including the need to design the premium taper and uplift mechanisms, and the need to establish effective grandfathering. Care is also needed to set the width of the band between the cap and collar to get the right balance of static and dynamic efficiency. At this stage, we believe that this approach may well work better than the FIT with CFD option, but further work is needed on the detail of both options before this conclusion can be drawn with certainty.

Among the issues which should be considered in developing the mechanisms (and which will inform the final choice), are:

(a) *Wind divergence (also known as "cannibalisation").* Because wind will be a large proportion of total capacity, there will tend to be excess supply (and therefore prices will tend to be low) when the wind is blowing. The "wind-weighted" power price will therefore diverge increasingly from the "time weighted" average power price. One estimate puts this effect at 10% by 2025. Increasing baseload nuclear generation, promoted by EMR, will tend to exacerbate this effect. Both the Variable PFIT and the FIT with CFD models provide options to mitigate the impact, principally through making payments at least in part based on availability (see our response to Question 11).

(b) *Dispatch Efficiency.* The FIT will require to be designed to prevent inefficient dispatch by supported generation causing negative pricing to occur in the market. There are a number of potential solutions to this that require further examination, such as limiting FIT eligibility to a certain number of hours, profiling forward dispatch into certain percentages in certain timeframes or simply disallowing FIT support during negative price periods to all or certain technologies.

(c) *CFD index period*. It is likely that nuclear plant would settle against an annual index as this provides the right market price signal for timing of non-forced outages and to manage seasonal availability. For renewables, the choice is more complex. An annual index maximises the market incentives but because of divergence, a CFD supported wind farm would receive a figure significantly below the strike price. This would require a divergence related uplift to be incorporated in the CFD (or indeed Variable PFIT) in order that it paid out the intended total price. That uplift might need to be calculated in terms of the total amount of wind and nuclear plant in the system. An alternative might be to have a much shorter index period for renewables, reducing the risk and any incentives, and moving the system closer to a fixed FIT.

(d) *Liquidity and hedging impacts (basis risk).* The reference index must be highly visible to the market participants, with sufficient supply and demand in the market to provide a liquid market. Careful attention will be required as to contract lengths and coincidence in time of contract renewals. At the point where the index price under a CFD is fixed, this transfers market risk from the consumer to the generator. This creates an unhedged price risk for the generator which may affect the risk limits that are generally imposed on traders. By applying the index (whatever its period) to generation in weekly or monthly tranches, this may help avoid problems with liquidity in forward markets and may also help reduce the risk of manipulation of the price index. Hedging issues will be problematic in any event for intermittent generation due to unknown volumes until close to dispatch, leading to more trading on the spot market, for both the CFD and variable PFIT options.

(e) *Duration.* Consideration should be given as to the optimum contract or PFIT duration and any profiling of payments. The duration should not exceed the economic life of the asset, but could be at a higher price or premium and shorter (possibly with the

(f) *Pricing.* A technology specific CFD strike price or set of PFIT parameters will be required to recognise the different cost and risks seen by each technology. As discussed later, the use of auctions is not appropriate for price setting at this stage and has had a poor record in this area;

(g) *Development of prices over time.* The CFD strike price or PFIT parameters will require to be linked to RPI and other indices may require to be incorporated. For example, a steel index and possibly one relating to general construction industry inflation could be appropriate for offshore wind and nuclear given their exposure to construction costs over long planning and construction periods. Other costs that are not under the control of the generator may also require consideration, including regulated costs e.g. transmission charges and business rates;

(h) Institutional design for CFDs. It is necessary to consider who the counterparty might be to a CFD, how its financial strength is assured, and how the costs are charged to suppliers. It would be appropriate as a matter of principle for the FIT with CFD system to be voluntary (especially if the CFD is two-way); if a generator wishes to take its chance in the market rather than have the Government's price, it must be entitled to do so. In general, these issues look less complex for a variable PFIT.

(i) Other funding sources. It may be sensible for the Government to review, having regard to the overall level of electricity prices and competitiveness issues, whether some support for low carbon generation might also come from other funding streams such as tax credits or CO_2 auction receipts, as envisaged by the EU ETS directive.

For both the FIT with CFD and Variable PFIT options, it would be sensible to integrate the development of the mechanism with decisions on capacity payments. Making low carbon firm plant (which has some load following capability) eligible for the capacity payment would be logical and would comprise a useful (if relatively small) component of the support and risk reduction package needed by firm low carbon plant, whether the FIT with CFD or Variable PFIT applies

In conclusion, much work is still needed to establish exactly how the options would work and whether there are unintended consequences to avoid. We are happy to play our part in carrying that work forward so that a sound decision can be taken.

Q5. What do you see as the advantages/disadvantages of transferring different risks from the generator or supplier to the Government? In particular, what are the implications of removing the (long term) electricity price risk from generators under the CFD model?

We have answered this question in terms of transfer of risks to the consumer, under supervision by the Government, rather than to the Government itself.

We broadly concur that it will be beneficial to remove some or all of the long term electricity price risk from low carbon generators. While we do not think that this will lead to a meaningful and easily quantified impact on the cost of capital, it will remove the need for the Government to make an "accurate" estimate of future electricity prices in setting support levels. This will make it easier to decide on support levels and will make it easier for managements to assess projects – especially for projects like new nuclear power stations where potential variations in the market price could affect a large proportion of the project's total remuneration. Indeed, absent some mechanism for transferring this risk to consumers, financing new nuclear plant could be very challenging. There is somewhat more flexibility here for renewables, because the market price is typically a smaller part of the total and the investments are smaller, but transferring all or part of this risk will positively help the risk profile of such investments.

We think that these risk profile changes are likely to assist with investment decisions but are unlikely to have a significant direct impact on the cost of capital. See our answer to question 7.

It is worth noting that such a transfer is reasonable on theoretical grounds, in that it is for Governments to set policy requiring low carbon generation. To the extent that the cost difference with the fossil alternative is under-estimated, this is a risk that is properly a matter for Government or the consumer and not for the Companies that come forward with investments to meet those targets.

If we are to achieve Government's low carbon goal, it will be imperative that players in this market have the ability to attract finance. For this reason, the new arrangements must be highly predictable and offer internationally competitive levels of return. There may also be a need across the package of measures (especially in regard to FIT) that First of a Kind technology is offered slightly higher FIT reward levels (or additional funding from an organisation such as the Green Investment Bank) than well established technologies

With regards to transferral of risk, it is clear that some risks (beyond the operational and construction risks that are in any event for the market to manage) will remain with suppliers or generators, even under a CFD model, for example;

- ***Hedging Risk*** - Hedging risks will exist around the selection of strike price reference or index values.

- ***Balancing & Negative Pricing Risk*** - Risks are likely to be increased as the proportion of intermittent and inflexible generation comes onto the system – especially where some technologies are not complementary in behaviour and control.

- ***Value Risk*** - CFD payment value risk will be created if the electricity price index is inappropriate, unreliable, or is not transparent or if the strike price is not properly set or adjusted to accommodate the necessary discount put to generators by market traders.

- ***Political Risk*** – It is clear these reforms increase regulatory and political intervention risk. We would prefer solutions that remain market based where possible to allow effective risk quantification when seeking new capital from investors.

We look forward to working with Government to address these risks.

Q6. What are the efficient operational decisions that the price signal incentivises? How important are these for the market to function properly? How would they be affected by the proposed policy?

Low carbon technologies (other than CCS) are characterised by very low marginal prices with the result that such plants have an incentive to generate at the maximum level they are capable of at the time. Such plants are therefore unlikely to be able to offer the system much upward flexibility in output as any available output is likely already to be being produced.

However, low carbon plant can contribute to system stability by offering downward flexibility. Modern nuclear plants can reduce their output in order to follow load, though it may not be sensible to switch off completely. Similarly, wind farms can reduce output below the available level if the electricity is not required.

Depending on the structure of the support mechanism, exposing low carbon plant to short term price signals will give it an incentive to play as much of a role as is practicable and economic in the balancing of the system. At some times of the year, this will become increasingly important as the combination of renewables, nuclear and spinning reserve may exceed demand, and some low carbon plant will need to be incentivised to switch off or turn down in order to maintain system stability.

It would be possible to create such incentives even if such plant was in receipt of a fixed FIT, But it would be more expensive and complex because off-market mechanisms would be needed to compensate the plant for the non-receipt of the FIT and the disruption of starting and stopping. These may not find the most cost effective answer across the generation fleet.

The other major area where operational decisions are affected by market signals is in the scheduling of maintenance and other outages. This can apply in the short term, where a plant develops a fault which requires a shutdown for repairs, but can safely carry on running for a few days until a convenient moment. This is a standard procedure in our thermal fleet but may also be relevant on occasion to low carbon plant.

Market signals can also be important for optimising scheduled maintenance. For example, a nuclear plant can plan its operational profile far in advance and can take account of longer term price signals in its planning. Under a CFD or variable PFIT model maintenance would be incentivised to periods of lower demand and price. (To illustrate, if a nuclear generator has a CFD with an annual index, it would be likely to sell baseload for an entire year forward to capture the risk free price. It would still be incentivised to schedule maintenance for the cheapest periods to allow it to buy back the power it had sold but would not be generating from the market at the cheapest price).

For wind generation, operational profiles cannot be determined until closer to dispatch. However, efficient operational decisions such as maintenance are less of a problem as almost all of the outages are done on a piecemeal basis with only a few turbines, at most, out of service at any one time. Like nuclear, there would still be an incentive to take any major outages during periods of low demand and price.

Offshore wind planned maintenance is likely to be less impacted by market prices because winter weather constrains maintenance to summer months.

Q7. Do you agree with the Government's assessment of the impact of the different models of FITs on the cost of capital for low carbon generators?

We agree that some method of transferring all or part of the long term electricity price risk to consumers will make it easier to set FIT or other support price levels and may make long lead time high cost projects easier for investors to consider. However, we are not convinced that attempting to quantify this into a cost of capital change, in the manner of Redpoint's analysis, is very meaningful.

The cost of capital for technologies like offshore wind is high principally because of the very significant up front development and construction cost risks. We do not think that financial investors are likely to be attracted to those risks, though they might be interested in buying operating projects. Generally, we think that the hurdle rates quoted for onshore wind in particular appear extremely low, especially in a climate where the technology, which is crucial to Government meeting its decarbonisation objectives, is competing for finance with other technologies offering a higher rate of return.

It is also unclear to us whether detailed risks such as basis and counterparty risks have been fully accounted for.

We also think that it would be a mistake to cut returns to onshore wind through the EMR process. Although onshore wind is getting more expensive due to current and forecast above-inflation increases in turbine costs, transmission charges and land/planning costs (rents, rates, community benefit etc.), it remains the least expensive large scale option for addressing the UK's renewables targets. There is a broad range of project returns onshore and we think the system should encourage as many of the projects as possible to proceed.

The attached note prepared for us by Oxera indicates that cutting the returns for new onshore projects could significantly reduce delivery. If a cut of 7% took place for projects completed after April 2017 without a corresponding fall in hurdle rates, onshore wind delivery could be some 6.2 TWh a year lower by 2020. If the resulting deficit in the renewables target was made up by increased construction of offshore wind, the additional costs to consumers would exceed the savings in onshore support payments by about £380 million a year.

Oxera also conclude that even if the Government was right that its EMR proposals would reduce the cost of capital for onshore wind, maintaining existing support levels could cut costs for consumers. Oxera estimate that if onshore wind commissioning from 2017 had a 7% increase in its returns (after the cost of capital) as a result of the risk reduction from EMR with no change in support levels, then around 5.8 TWh a year of extra onshore wind would be deployed by 2020. If this substituted for an equivalent amount of offshore wind generation, the saving to consumers would be around £288m a year in 2020. So whether or not the Government is right in its contention that EMR will cut the cost of capital for onshore wind, it is not in consumers' interests to cut the support for this technology.

Q8. What impact do you think the different models of FITs will have on the availability of finance for low-carbon electricity generation investments from both new investors and the existing investor base?

We agree that transferring all or part of the wholesale price risk to consumers is likely to be helpful in attracting capital, provided that the Government is not tempted to reduce the rates of return.

In terms of the various models, we think a fixed FIT; a FIT with CFD; and our proposal of a variable PFIT will benefit from this advantage. A straightforward Premium FIT would not.

We doubt that, at the current level of market maturity, debt investors would be interested in low carbon projects during the development and construction stage, other than through investing in the utilities owning them. Outside the regulated monopoly field, we think that the scope for high levels of gearing is limited.

Q9. What impact do you think the different models of FITs will have on different types of generators (eg 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?

We think that the main differential impact by type of generator arises from the fact that these proposals are necessarily very complex and will require sophisticated energy management skills to operate effectively. Larger companies are more likely to have the resources to handle the complexity than small ones, and for this reason we think that it may be sensible to use a fixed FIT model for the smallest generators, recognising that this will prevent them from playing their role in efficient dispatch of the wider system.

Under a CFD model, small generators could use an energy management service to manage their indexation within their CFD – this could increase the roll of aggregators, or could be done under contracts similar to power purchase agreements (PPAs) that currently exist. The price offered under such contracts should be linked to the risks associated with trading the index. The strike price of any CFD should include an energy management fee, which could be set lower if indexes are well designed.

For independent renewable generators, the premium FIT model is closest to the Renewables Obligation and it is likely that it would have little direct impact on their behaviours. However, the dynamics of the wholesale power market are also set to change. The penetration of wind will affect spot markets meaning risk premia for managing outputs will also be likely to increase. If CFDs and associated indexes are designed properly, and the market functions well, some of these risks may be mitigated somewhat.

In terms of relationships between (independent) generators and electricity suppliers, we think that the EMR reforms are unlikely to make a significant difference. Under the existing renewables obligation, there is no requirement on suppliers to buy renewable energy as they can pay the buy-out. However, suppliers compete to write PPAs with renewable generators, taking account of the risk factors (including the intermittency of wind) which require a discount to be applied to the ROC and power prices. That discount is likely to increase as the quantity of wind on the system rises and the wind-weighted price diverges increasingly from the time-weighted price.

Q10. How important do you think greater liquidity in the wholesale market is to the effective operation of the FIT with CFD model? What reference price or index should be used?

There are two important issues here. The first is the effect of liquidity on the support mechanism and the ability for non-integrated low carbon generators to enter the market; and the second is the impact of the EMR arrangements on liquidity.

The liquidity requirements for the FIT with CFD model are essentially to have a sufficiently firm reference price in order to operate the indexing mechanism without the risk of distortion or gaming. Similar issues arise for the Variable PFIT model we have proposed. Whether the existing market provides a sufficiently solid basis for this (or will do by the time that the new system is in place) will depend on the index period used. There is substantial liquidity for example, in baseload power up to a year ahead; longer dated contracts and shape (eg peak or off-peak) tend to be less liquid.

The FIT with CFD and Variable PFIT would however reduce the need for low carbon entrants to trade beyond the index period. This is because the mechanism would offer them protection against market movements beyond the index period. So trading beyond the index period would both be less necessary (because consumers will be taking the risk) and difficult (because the seller would face basis risk in selling the power beyond the index period).

We in ScottishPower have already announced our Six Commitments to improve contestability and access to the market for small suppliers and generators. We would like to see other suppliers follow our lead on contestability initiatives and we are keen to participate in further initiatives to improve liquidity that are designed well and do not distort the market. However, it will be important to be clear what the liquidity requirements are, both of the indexing system and of potential entrants, before considering how they are to be delivered.

The other key ingredient on this is how the proposed CFD system will impact on liquidity. If poorly designed, it could have a negative impact as companies may try to align their trading strategies to the index in order to avoid basis risk. Indeed, it is possible that any trading approach that diverged from the index would be classed as speculative.

At the point where the index price under a CFD is fixed, this transfers market risk from the consumer to the generator. This creates an unhedged price risk for the generator which may affect the risk limits that are generally imposed on traders. By applying the index (whatever its period) to generation in weekly or monthly tranches, this may help avoid problems with liquidity in forward markets and may also help reduce the risk of manipulation of the price index. Hedging issues will be problematic in any event for intermittent generation due to unknown volumes until close to dispatch, leading to more trading on the spot market, for both the CFD and variable PFIT options.

It is likely that nuclear plant would settle against an annual index as this provides the right market price signal for timing of non-forced outages and to manage seasonal availability. For renewables, the choice is more complex. An annual index maximises the market incentives but because of divergence, a CFD supported wind farm would receive a figure significantly below the strike price. This would require a divergence related uplift to be incorporated in the CFD (or indeed Variable PFIT) in order that it paid out the intended total price. That uplift might need to be calculated in terms of the total amount of wind and nuclear plant in the system. An alternative might be to have a much shorter index period for renewables, reducing the risk and any incentives, and moving the system closer to a fixed FIT.

Designing an appropriate index will be a challenging task and it is imperative that we find the right solution. We look forward to working further with the Government on this.

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

There are pros and cons of each option. Broadly, payment on output is easier to measure and incentivises reliable, working plant. But it leaves capital intensive plant with volume risk if there is a possibility that not all low carbon plant is dispatched and it can incentivise negative pricing because low marginal cost low carbon plant will not turn off until the energy price is at least negative enough to cancel the support payments. Payment on availability has the converse characteristics.

Among the options that could be considered to mitigate negative pricing and encourage sensible dispatch are:

(a) Paying the FIT on output but disallowing access to FIT support in negative price periods. It would be necessary to watch out for distortions or gaming opportunities that might emerge as a result of the discontinuity when the wholesale price crosses zero. It would also be necessary to uplift the FIT to take account of the reduced pay-out.

(b) Paying the FIT on output but rewarding a maximum volume of energy for each project on an annual basis. The maximum amount of energy which is in the scope of a FIT would be based on a specified load factor and capacity of a site. This could be set at around two thirds of the typical annual output with a commensurate uplift in the FIT. Further output would be rewarded by the electricity market price alone. This would help encourage economically rational dispatch and would afford plant operators with a degree of protection against demand risk.

(c) Paying the FIT on output but limiting the number of hours which receive support. This is similar to option (b) but there is a complication especially for wind (where output varies strongly hour by hour) in choosing which hours are supported. If it is the hours with the biggest output, there may be a correlation between that and times when the power is not required.

(d) Paying the FIT on availability or capacity, or partly on this with the balance on output.

In all of this, there are specific design elements that may encourage efficient dispatch and the development of sites with the best resources. However, to achieve some of these outcomes additional complexity may have to be introduced. We encourage further engagement with industry to address such benefits and the optimum design.

Emissions Performance Standard

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?

We are yet to be convinced that there is a need for an emissions performance standard. It does not seem likely to promote the construction of any low carbon generation and, unless carefully designed, could be detrimental to security of supply. As carbon prices rise to meet global decarbonisation targets, the amount of running that would be economic for high carbon stations is bound to be curtailed. An EPS does not help Europe reduce its total CO_2 emissions, as any reductions in the UK are likely to be balanced elsewhere. In contrast, the EU ETS is effective as a way to move Europe toward decarbonisation targets,

We perceive the major concern with the introduction of an EPS to be the impact that uncertainty in such arrangements may have on investor confidence. Accordingly, we share the views expressed in the consultation on the need for grandfathering arrangements that determine any such applicable EPS level at the point of consent, without the threat of any retrospective tightening of that level.

Accordingly, the design of EPS set out in the consultation document seems unlikely to have significant negative impacts on security of supply, providing that the grandfathering arrangements are clear and set out in primary legislation. We think great caution is needed in making any exception from grandfathering around plant upgrades if investment is not to be deterred.

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?

We favour converting the rate to an annual total, based on baseload operation, as this reflects the likely mode of operation of the current comparator - a new CCGT. Of the EPS cap options proposed by DECC, we favour the simple figure of 600 g CO_2/kWh and we concur with the assessment that this would be consistent with the other requirements of the wider CCS Demonstration Programme and would be less likely to have an adverse impact on the development of the technology.

To adopt the lower limit of 450 g CO_2/KWh, at a time when as yet the technological capability of CCS remains uncertain, might introduce further uncertainty and we share the reservations expressed about the potentially detrimental impact on CCS development. Moreover, adopting that lower limit may only introduce further complications around the possible need to exempt demonstration plant from such a limit and the potentially discriminatory implications that that may have.

We believe that those demonstration projects that form part of either the UK or EU Demonstration Programme should be provided with appropriate, limited derogation from any such EPS requirements to the full extent of their demonstration capability, to reflect their first of a kind status and their distinct priority to demonstrate the technology. Inevitably, pioneering any new technology will result in performance and operational uncertainties that would be difficult to envisage or predict with any great precision. Additionally, CCS demonstration brings the added element that such issues may not even be in respect of the generation plant itself, but may be as a result of problems elsewhere in the CCS chain, such as with compression facilities, transportation, injection equipment or the CO_2 store itself.

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?

We fully support the proposal that the EPS should be targeted at new plant with grandfathered safeguards, as stated above. We believe that the fundamental issue should be establishing certainty at the time of investment being committed. That can be delivered by clear and unequivocal "grandfathering" principles being established within the consenting process, and firm and fixed performance requirements being incorporated within the consent granted.

Such requirements must be protected from subsequent retrospective review as that uncertainty could hinder or obstruct the investment decision making process. Accordingly, we would advocate that such provisions should be enshrined in primary legislation, further bolstering the protection of those investment decisions.

The grandfathering should not be applied for a fixed period, but like planning permission, should apply for the actual lifetime of the installation. This is an established principle that developers understand and accept and avoids complex assessments of the economic lifetime of the asset. As carbon prices rise to meet tighter international targets the output from any high carbon plant will in any event be constrained, so such as approach should not create any environmental risk.

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?

We think great caution is needed in making any exception from grandfathering around plant upgrades, if investment is not to be deterred. There clearly has to be a point at which changes to an existing plant are so extensive that the plant is essentially a new one, but we would not advocate drawing the scope of EPS application any wider. Otherwise, investors will be discouraged from putting in place the plant needed to maintain security of supply.

We welcome the specific exclusions already recognised for SCR installation and retrofit of CCS but consider that the exceptions should be drawn more widely. In particular, we consider that upgrades that are required to comply with future environmental regulation should similarly be excluded as should investment made to upgrade the plant to improve overall efficiency.

As regards life extension, this is complex because most plant does not have a fixed lifetime and there is a very uncertain line between maintenance expenditure (without which the plant would in time stop operating) and life extension investment. We must remain mindful of the significant role that existing plant will play both in the demonstration of CCS between now and 2020 and in facilitating the transition to the low carbon generation future. To that extent, we must not create an environment that leads to the premature retirement of existing plant that could contribute to that process, whilst maintaining security of supply at an affordable cost to the consumer.

We think that grandfathering should apply for the physical lifetime of the plant. In terms of when a plant is "new" it could be appropriate to draw on the definition in the Large Combustion Plant Directive which talks of "technical apparatus in which fuel is oxidised in order to use the heat thus generated" – i.e. that the EPS is applied when that apparatus is entirely replaced (except for like for like replacements for maintenance).

Using that definition, for example, repowering a power station would engage the EPS, which upgrading the turbine would not. We think this is a reasonable place to draw the line.

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

Subject to the inclusion within the final package of appropriate grandfathering arrangements as detailed above, we agree that it would be prudent to keep the EPS under review, both in terms of structure and applicable levels. In that way the lessons learned from the development of CCS, which is a nascent technology, could then be incorporated appropriately for future consenting processes.

We would support the inclusion of such an EPS review within the progress reports required by the Energy Act 2010 into the decarbonisation of electricity generation. In that way, EPS would be able to be considered in the wider context of progress towards decarbonisation and within a review cycle that would be appropriate to reflect potential advances in CCS technology.

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

It appears to us to be sensible that CO_2 emissions from biomass should be zero-rated for the purposes of meeting an EPS. Indeed, it would appear logical then to extend that principle to recognise that biomass generation fitted with CCS should qualify for some kind of negative rating to reflect the overall impact on emission levels.

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

It would be prudent to allow exceptions to the EPS not only for short-term energy shortfalls but also system stability issues that may justify an exceptional approach. However, the concept of a long-term energy shortfall would suggest that a more comprehensive solution may be required.

Capacity Mechanisms

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

As discussed above, we believe that the rapid expansion of renewables and nuclear in response to Government policy will tend to make load factors for conventional plant lower and less predictable. This will interfere with the natural ability of an energy-only market to balance supply and demand and put existing plants, which currently guarantee security of supply, at risk of premature closure. In addition to the large scale closures that must happen between now and 2015 under the LCPD, some 20 GW of coal, old gas and nuclear plant may close in the following 10 years. This is a huge loss of firm capacity which will require strong action to avoid the risk of significant shortfalls, especially during periods when there is little wind. In consequence, despite our normal preference for energy-only markets, it is clear that a well designed capacity mechanism will be needed in GB in order to ensure that there is sufficient backup, especially given the low level of interconnection capacity.

It is important to be clear where the security of supply problem is likely to arise. The consultation paper suggests that a key concern is the very short term ramp rate, caused by sudden or unexpected changes in wind velocity. However the attached analysis by Nera suggests that this should be manageable with typical thermal plant, especially when supported by demand side actions. The more difficult problem is likely to be the need for large amounts of power during sustained periods, such as calm intervals in winter where low temperatures and low wind generation can coincide for up to a fortnight – well beyond the time horizon of currently envisaged demand side options. This will need substantial generation assets – it is unlikely that a few new open cycle gas turbines will be a sufficient and effective solution in such cases.

The objective of the capacity mechanism must therefore be to bring forward and retain in operation flexible, appropriately sized plant at the system level, whilst maintaining integrity of returns in the remainder of the fleet and should address the growing “missing money” problem.

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

Given one of the main objectives of Government policy is to ensure security of supply, and taking account of the pros and cons discussed above, we believe the proposal to introduce a capacity mechanism to the current electricity market, should be a key element of the reforms, and should be implemented in addition to the improvements to the current market.

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

In broad terms, any capacity mechanism that is effective in reducing scarcity and energy unserved is likely to dampen peak pricing and therefore reduce average wholesale prices. Conversely, a capacity mechanism that is ineffective in reducing scarcity will not have an impact on wholesale prices (other than through the need to fund the cost of the mechanism), but neither will it improve security of supply.

We suspect that the proposed targeted mechanism would have little impact either on prices or on security of supply. The reason is that the tendered plant would be visible to the market some time before it was put into operation. As a result market participants will see the likely degradation of scarcity premia and hold back from building plant in the market or making necessary investments to maintain existing plant. The likely result is that equilibrium will be re-established at more or less the same level of supply security as before, but with the tendered plant replacing an element of the market plant.

It seems unlikely that restricting the operation of the tendered plant to periods when a power shortfall is imminent will avoid the impact of this. Scarcity premia only work in bringing forward new plant or maintain old because the plant provides some insurance against the very costly impacts of being short when there is excess demand when the price could rise as high as the value of lost load (VOLL). If the tendered plant is going to provide "free" insurance against such an eventuality, it will inevitably reduce the amount of insurance that needs to be paid for by the market.

We have also looked at the impact on prices of a successful capacity scheme – one which is sufficiently broad that it rewards all plant that helps back up wind or at least all such plant not in receipt of a FIT. Such a scheme will lead to a reduction in wholesale prices, net of the cost of the capacity payments, as a result of lower scarcity. The attached analysis by Nera models a case showing that around 73% of the cost of the capacity payments is returned to customers through lower wholesale prices. Other analyses, such as the original Redpoint/Energy Strategies study for Government in 2007[1], similarly concluded that the great majority of the cost of the capacity payments is returned to consumers through lower wholesale prices, though the precise figures depend on the detailed modelling assumptions. The additional income that generators receive in this approach is essentially the cost of replacing the "missing money" that the capacity mechanism is intended to address, and is broadly balanced for the consumers by the reduced likelihood of supply interruptions.

There is however a separate impact from the proposed capacity mechanism on renewables supported by the RO, in that it will put a downward pressure on wholesale prices and therefore returns. Investors will expect a suitable solution to this to be found. One option would be to increase the headroom level to compensate RO-supported renewables; another

[1] Dynamics of GB Electricity Generation Investment, 18/5/2007 http://webarchive.nationalarchives.gov.uk/+/http://www.berr.gov.uk/files/file38972.pdf

might be for such renewables (or their output) to be exempted from whatever levy funds capacity payments. We suspect that paying a capacity credit to RO supported renewables is the least favoured solution as it could defeat the point of the mechanism, which is to support back-ups to wind.

It is important that the presence of the capacity mechanism (and whether or not the technology in question is or is not eligible to receive capacity payments) is factored into assumptions regarding the structure and level of FIT payments for eligible plant. All things being equal, the reference price will be reduced for FIT plant below their "normal" long run average. This reference price will therefore not reflect the full market benefits such as security of supply.

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.

As mentioned in our answer to Question 19, the principal security of supply problem will not be short term ramp rates, but the ability of the system to keep going through a prolonged lack of wind energy, well beyond the time periods which current storage and demand side options can manage. The Nera analysis demonstrates that the Government's current proposal for a targeted capacity mechanism will not work in this context, unless the "target" is so broad as to encompass substantially all firm plant. This is because, if the mechanism alleviates shortages, it will depress the peaks in the wholesale price. This will reduce the remuneration of plant that is not within the targeted sector causing it to close or not be built. Inevitably, this ends up with the Government, and not private industry, being the dominant force commissioning electricity generating plant.

A broader mechanism, applying a suitably determined capacity payment to all firm plant, does not have this disadvantage. Plant investment decisions remain with the industry and Government has a much smaller role. Because the additional capacity built or maintained in operation will reduce price spikes, we judge that most of the gross cost of the scheme will be returned to customers, the balance being the cost of providing the additional supply security. We think that the broad scheme should apply in particular to the following:

Firm, Flexible Plant

Forms of firm generation, including the more flexible generation such as CCGT, OCGT and conventional coal stations, should be placed directly into a capacity payments regime.

This will ensure that existing plant (i.e. older coal and gas plant operating at low load factors) can receive suitable compensation to ensure their continuing availability. As the Government set out in the consultation paper, many of these types of plant are likely to be economically fragile and need a contribution to fixed costs to continue operation. For investors, capacity payments for existing plant will encourage life extension that can, in turn, provide valuable, low cost, low load factor back up to the system. It is essential that much existing plant continues operation to ensure the Government's target level of expected energy un-served and the associated target of between 8% and 12% de-rated capacity margin.

For new plant, such a capacity payment arrangement may be essential to bring forward new investment. It is important that all new "firm and flexible " plant have strong and unequivocal signals that support their availability and therefore all flexible and firm plant outside a FIT arrangement must be eligible for a capacity payment. Such clarity will help investors decide on the benefits of new plant investment. This is likely to be important in a market that, in some respects, may be even more risky and unpredictable for "market only" plant that does not receive other backstop regulatory support via FITs or the RO.

Firm Plant Supported by a FIT

We think that the capacity mechanism should apply to firm plant supported by a low carbon FIT. This is logical, since the plant will be contributing to security of supply, and such an approach would comprise a useful (if relatively small) component of the support and risk reduction package needed by firm low carbon generation, whether the FIT with CFD or Variable PFIT applies. Nera's paper has analysed a slightly different case, where FIT supported plant did not qualify for capacity payments and the level of FIT support for firm low carbon generation was correspondingly greater; however this does not affect the fundamental conclusion about the need for a broad scheme. Clearly, it would make sense to reach conclusions on the FIT terms and any applicable capacity payments in a joined-up manner to achieve the desired total support package.

We have the following comments on Government's preferred design proposals:

A central body holding the responsibility

- We agree that it would be more practical if responsibility for setting the capacity payment mechanism and the balancing mechanism was held by a central authority.
- Capacity price level and how the market is likely to function at different levels needs to be widely understood. The price level will be informed by a balanced judgement of a central body that considers forecast need, mix of likely plant available and technical system needs. We therefore encourage strong dialogue with industry and independent experts in the price setting process and that full account be taken of the likely structure / success of the FIT policy in deriving supported electricity capacity for nuclear, renewable and CCS plant.

Volume based and price based

- We agree that a targeted mechanism would need to be volume based as this is the essence of such an approach. However, all the analysis we have suggests that such an approach would not achieve its objectives.
- On the basis of a broader scheme, we recognise the risk that a price-only scheme might over-deliver, and a volume-only scheme might drift into a targeted approach. However there are intermediate options which look promising – essentially taking the best elements of volume and price basing.
- One way to combine these is to set aside a fixed amount of money for capacity payments, which is then divided equally per MW of eligible capacity. To the extent that the eligible portfolio grows, the unit payment will fall. This is similar to the Irish scheme.

A targeted mechanism, rather than market-wide

- We have discussed above why this choice does not seem apt if the scheme is intended to improve security of supply.

- The consultation document appears to recognise to some extent the missing money problem that arises from the dichotomy between long run marginal cost investments and short run competitive markets. We believe this issue has been exacerbated by increase in costs over the last five years. (35) *"under the current arrangements, peak wholesale prices may not rise high enough to reimburse generators and therefore will not incentivise developers to invest in sufficient new capacity".* The impact assessment (91) also suggests a targeted capacity mechanism will distort scarcity rents that ensure all capacity achieves an adequate return. If these returns are taken out of the market and not replaced by other revenues, the capacity mechanism will soon widen to prevent closures and bring on much needed capacity. It is also stated that Government expects these issues could be mitigated through design. It is difficult to envisage how such a design could work in practice and further clarification is needed.

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?

Although a large part of the security of supply problem arises in respect of time periods too long for many of these technologies to be well placed to respond, there can be no doubt that the measures listed in this question can play a useful role in assisting with security of supply, especially in respect of shorter term issues.

The capacity mechanism should include arrangements for storage, especially pumped storage, which is highly valuable to system security but needs stronger signals to see capacity expanded. The position on interconnection is less clear, since it is not always the case that interconnectors import power into th UK when our system is tight. Interconnectors should only be included in a capacity mechanism if it is backed up with long term guarantees of physical plant with sufficient penalties should the option to call generation not materialise.

We would think it appropriate in principle that demand side management (DSM) options should benefit from a capacity payment (though there may be a case for reducing the payment if the DSM option can only shift demand by a few hours). However, we are not dogmatic about this – there could be other incentives for DSM that could be created outside a capacity payment and this option could be considered if fitting DSM directly within the capacity mechanism proved problematic for technical reasons. One important consideration will be whether the DSM option can in fact deliver the demand reduction with the predictability required. There have been some difficulties in the past with interruptible gas contracts and it is sometimes hard to establish reliably what the demand would have been absent the DSM measure or what the true capacity of a DSM measure is unless it is used.

The scale of DSM may increase over time as smart meters are deployed, trading and settlement systems adjust to be more granular and smart grids expand. The importance and responsiveness of DSM may also be improved by changes in technology and usage – such as electric vehicles and new types of electrical heating / energy recovery. There is probably scope at this time for demand side bidding for I&C customers to be expanded. It may be useful to review whether this is best achieved by expanding Short Term Operating Reserve (STOR) operations or by inclusion within a capacity payments system.

We believe there is a role for measures such as cost effective micro generation and energy efficiency to contribute to greater security of supply. Current policies are supportive of these technologies. However, while they help improve static security of supply by reducing overall demand, they cannot respond directly to short term signals from the market or the system operator. At this stage, we do not think that these mechanisms are yet responsive enough to provide system security at the level required.   Accordingly, they should continue to be supported outside the capacity mechanism.

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

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

As stated earlier a targeted capacity mechanism is not our preferred option, however, if it were to be implemented, in principle, the economic dispatch approach – extending STOR for the market seems to be the better option of the two. We believe that this will be the less expensive option, though either will lead to market distortions.

Care should be taken in making comparisons with other markets. In particular, reference is made to the Swedish capacity payment as a potential example of how the system may be constructed in the UK. However, Swedish generating capacity consists of 46% hydro and 43% nuclear and Sweden is part of the Nordic Pool system. We consider this scheme to be more a water management type of payment, as opposed to a large scale backup mechanism as needed in the UK.

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

We think that creating a location element for capacity payments would be an unnecessary complication which could increase uncertainty. The objective of a capacity payment should be to encourage sufficient generation to be available in order to satisfy GB demand when intermittent generation is not able to do so. This is generally a system-wide problem and the normal incentives to encourage sensible location of plant which is flexible as to where it is installed (currently under review in Project TransmiT) should be sufficient to deal with any locational issues.

It is worth noting that the ideal locations of backup plant in a constrained system may not be the same as the ideal positions for plant that is expected to be generating when the system is close to being full. For example, backup plant in Scotland will have no difficulty exporting its power at times when the majority of the onshore wind fleet in that country is becalmed.

In summary, we think that locational capacity pricing would add little to the existing mechanisms and should not be pursued.

Packages of Options

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?

Of the four packages of options mentioned, we think that the Goverment's preferred one seems the most likely to bring forward investment across renewable, nuclear and CCS as a whole   It also has the potential to be the most cost effective although we question whether the inclusion of carbon price support in the package will achieve sufficient progress in promoting low carbon investment to justify the cost to consumers.

In terms of the type of FIT that the package might contain, our preference is for a "Variable PFIT" i.e. a premium FIT with a cap and collar, which tapers (eventually to zero) if the energy price rises above a fixed level and is augmented if the price falls below a lower threshold. We think this may have a number of advantages, described in our response to earlier questions, over the FIT with CFD option. Nevertheless, we think that, subject to development of the details, the FIT with CFD approach is the next best option to the Variable PFIT. We think that the pure premium FIT approach suffers from the problem that the level may be difficult to set, especially for nuclear.

Our concerns that a narrowly targeted capacity payment scheme will not work are set out in response to earlier questions.

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

We give views on each of the packages below:

We do not believe that Package 1 (namely carbon price support, EPS and capacity mechanism) is sufficient to meet the Government's decarbonisation, affordability and security objectives. The package is unlikely to provide the certainty required for investment in nuclear or CCS because a carbon price intervention alone is unlikely to be feasible at a level which would address the two main issues which the FIT system can address. These are the high level of cost of some technologies, and the susceptibility to electricity price risk for others. Package 1 is unlikely to provide stimulus for investors to release the billions of pounds of capital required for new low carbon base-load thermal generation.

Package 2 (namely, premium FIT, carbon price support, EPS and capacity mechanism) could be a credible alternative to the Government's preferred package of options. However, we would strongly recommend that such a premium FIT was fitted with a cap and collar mechanism. Without it, there would be great difficulty setting the premium at an appropriate level, especially for technologies like nuclear. Package 2 must also have a wide capacity payment scheme to be effective.

We do not favour Package 4 (namely, fixed payment FIT, carbon price support, EPS and capacity mechanism). We agree with the Government's conclusions on the fixed FIT option.

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?

Whether package 2 or 3 is chosen, we anticipate that a wider range of impacts will arise due to the electricity market reforms.

In order to deliver UK energy policy, we believe that investing to resolve grid constraints as a matter of urgency is in everyone's best interests and must be a priority. We support the Government's efforts to prioritise grid investment and facilitate a fit for purpose network to serve as a key enabler of energy policy. We are pleased that the key reinforcements have been identified through work undertaken by the GB transmission licensees in 2008 and 2009, as a working group to the Government's Electricity Networks Strategy Group (ENSG). The ENSG published their report in 2009 and the reinforcements detailed in this report were strongly validated in an updated cost-benefit analysis undertaken in 2010.

However, given the clear need case for these reinforcements, we are concerned that Ofgem's process for providing regulatory funding is effectively one year at a time through to

2013 (the start of the next transmission price control). Ideally, each essential project should have been provided with full funding for the full construction period. Ofgem's approach could delay investment and lead to higher constraint costs. A good example is the Western HVDC link where construction funding for 2011/12 for this project has yet to be agreed, and unless resolved by summer this year could lead to a delay beyond the current planned completion date in 2015.

Another risk to delivery is the planning system across the UK. A good example is the Beauly-Denny grid reinforcement in Scotland where the period from confirmation of need through to completing construction will be almost 15 years. Recent reforms to planning regimes in all parts of GB need to deliver outcomes more swiftly.

It is important that other barriers to investment arising from regulatory design are removed as efficiently as possible. The current transmission charging regime based on locational charges does not favour many renewable electricity or CCS investments in parts of the UK. This is the subject to the current TransmiT review, led by Ofgem, and we favour reform to remove locational charging in many cases, so as to accelerate much needed investment in new and existing plant. Decisions on the reform/removal of locational Transmission charges should co-incide with the Electricity Market Reform process to help guide investment decisions that need to be taken during 2011/12. These decisions will impact plant availability up to and beyond 2030.

It is also vital that the proposed reforms are compatible with other changes that are taking place in the electricity system to ensure that components of the system can work as effectively as possible together. There are major changes taking place in the next decade relating to the installation of smart metering, the emergence of smart grids, promotion of micro-generation and the creation of the Green Deal to foster greater energy efficiency. At first, these are likely to have limited effects on wholesale markets and major plant investment decisions. Over time, however, some of the changes that these activities will bring about may have more of an impact. While the package of reforms should not be driven by such possibilities, it is appropriate to bear them in mind.

Connection and integration with European electricity markets is desirable for both climate and security needs. It is important that the market reforms do not place undue restrictions on trading within the France-UK-Ireland system and that arrangements in respective markets are sufficiently compatible. It is also important that participants in the UK market are operating on a level playing field with European counterparts and there is no undue advantage for those importing into the UK system. All participants in the UK system should have the same rights and responsibilities.

Finally, there are clear interactions between EMR and the work that Ofgem is doing on liquidity. One of the key issues about the proposed CFDs is how the power produced under them will be integrated in the market. This will both affect liquidity because of the impact on hedging strategies and be affected by liquidity because of the need for a clear index.

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

A FIT (whether with CFD or a Variable PFIT), EPS and a wide Capacity Mechanism are broadly compatible and could work well together.

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A FIT with CFD or Variable PFIT will largely neutralise the impact of carbon price support on investment incentives, though carbon price support will reduce the impact of FITs on the Government's accounts (at some cost to consumers).

A broad capacity mechanism and the FIT system could overlap for firm low carbon plant and decisions on the two systems should ideally be taken together. We think it is probably best for low carbon plant to receive the capacity payment and the FIT level to be adjusted accordingly.

If carbon price support is set at a high level then, absent a strong and broad capacity signal, it is likely to force the early closure of the existing coal fleet by 2023 as the investments needed to meet the IED requirements would not be viable. This closure of some 18GW of flexible capacity could create serious problems for security of supply. Accordingly, strong carbon price support will require a strong capacity mechanism in order that it becomes viable to maintain existing coal in a peaking role.

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?

We agree with DECC's summation that the key implementation issues and associated risks fall into three broad categories and we believe these areas to be relevant, irrespective of the nature of the package:

Instrument design

Clarity in relation to the detail of the parameters and structure of the proposed reform mechanisms and exactly how they will function (independently as well as together), is vital in order to understand the specific implementation risks the overall package will present.

One of the most important aspects of the design will be the structure and level(s) of support for the feed-in tariff, with the risk being that the level(s) are not set correctly. Government must work with industry to ensure that support is sufficient to provide an economic return that is high enough for generators to invest, while also protecting the interests of consumers..

It will be essential that the FITs are available to all qualifying projects (while reserving the Government's ability to modify or withdraw the scheme for particular technologies prospectively given adequate notice). This approach will ensure that projects can be pulled through the development phase and that the complexities of a procurement process avoided. We provide our thoughts on the possibility of an auction approach under Q.31 below.

Institutional capability and framework

It is evident that, however the package of reforms is constructed, there will inevitably be important changes to the roles and responsibilities of the organisations charged with ensuring the functioning of the electricity market. Furthermore, with any change of this scale, there will be inherent risks. Once the final package is settled on, the specific activities and capabilities required within the key institutions, such as the system operator and the regulator, to manage each aspect of the package, and to manage the interactions between any new mechanisms and the existing framework, must be clearly defined. From this, the optimum arrangement of institutions must be configured. In order to manage potential risks, this must be done in such a way as to ensure the continued functioning of the market in a cost efficient manner whilst creating stability for market participants.

Ensuring a smooth transition

It is clear that bringing forward the necessary investment in a low carbon electricity system is vital to deliver on the Government's low carbon and renewables targets. A key barrier to achieving this level of investment in the appropriate technologies is uncertainty. Without a stable and predictable framework where uncertainty is minimised for a long time to come, market participants will delay investments and in some cases decide not to take the risk at all. Ensuring a smooth transition between the existing and future regime with clarity of timetable, institutional roles and responsibilities as well as the structure and nature of returns on investments, will be imperative to prevent any hiatus in developments coming forward.

We believe the proposed approach to the transition is broadly sound. However, we would observe:

- It will be important that key areas of policy including the initial CFD or Variable PFIT terms are determined as soon as possible, so that nuclear developers can consider investment decisions and renewables developers who might not be ready for 2017 can proceed with their investments.

- There should be an option for developers currently developing under the RO to switch to the FIT system. This is important as otherwise Government will feel a need to set the FIT with CFD or Variable PFIT to be less generous than the RO (to avoid developers waiting for the new system), only to find investment slowing thereafter.

- There needs to be a system to award a suitable FIT to wind farms intending to accredit under the RO in 2017, but which are delayed past the cut-off date because of construction problems.

- We think a hybrid approach to the RO – guaranteed headroom (calculation B) up until 2027 and then an equivalent fixed ROC or premium FIT thereafter – seems the best way to deal with the need to avoid disturbing Power Purchase Agreements in the next few years while avoiding unintended effects as 2037 approaches.

It will be important for industry to work with Government to help minimise the implementation risks and ensure that the final package delivers the progress that we need on renewables, nuclear and carbon capture and storage whilst keeping the interests of consumers firmly in mind, and we are committed to playing our part in this process.

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?**

We do not think that auctions are viable, at least prior to 2020. There are two key reasons why this is the case:

(a) The essence of an auction is that there must be disappointed bidders – i.e. developers with viable projects whose costs are higher than those of the successful bidders. However, this seems unlikely to happen in the cases of offshore wind and nuclear where the sites are already well known and in the hands of developers and the objective is to ensure that each one presses forward as soon as the developer is ready. It does not therefore seem possible to create price tension. In the case of onshore wind, the range of sites is greater and it could be possible to set a limited quota in order to create tension in an auction. However the result would be that fewer onshore wind sites would be developed than the number that were viable, so that the resulting gap in approaching the renewables target would have to be made up with other more expensive technologies such as offshore wind. Using auctions in relation to onshore wind would therefore be likely to increase costs to consumers.

(b) There are well established difficulties with integrating auctions with the project development cycle. In particular, if the auction takes place prior to the project being fully developed and having gained planning permission, the projects are too uncertain. This can lead to undeliverably low or uneconomically high bids, with the risk that investments either fail to go ahead at all or proceed with unnecessary costs for consumers. An example of this is the Non Fossil Fuel Obligation (NFFO) auctions where only 25% of winning projects were actually built (302 projects/2,659MW were awarded, 75 projects/391MW were actually built). Because the uncertainties are not resolved at the pre-planning stage, penalties for non-delivery are not realistic and would deter bidders.

    Conversely, if the auction takes place after planning permission, this creates a real difficulty in adequately incentivising the development cycle. The development cycle can be very expensive and it is essential that those putting projects together know that there will be a clear market for them to aim at. It is not reasonable for developers to spend many tens of £ millions on a project, only to be unsuccessful in an auction.

As well as the UK outcome with the Non-Fossil Fuels Obligation, international experience of auctions to support renewable power has also been negative, with tenders for wind abandoned in countries such as France and Ireland. The example given in the consultation document is of the Danish market which has a large number of differences to that operated in the UK. At the point of auction in the Danish market, the successful bidder has the site selected, the Environmental Impact Assessment undertaken and the consent granted. This is not the position in the UK.

Finally, an auction or tender based approach requires Government to determine the amount of low carbon generation in the electricity system and effectively determine the energy mix, instead of leaving this to the market. This is opposed to the market based approach to bringing forward projects, that has previously been advocated by Government.

Nevertheless we would be happy to work with the Government to consider suggestions as to how further price discovery can be built into an administrative approach. Possibly cost evidence could be supplied from the market players and appropriate checks and balances could be put in place to ensure the support levels set are realistic. Initially, we think the process will need to be a form of administrative pricing, operating in a manner akin to banding reviews, but we are happy to look at longer term options to achieve further price discovery.

- **Should auctions, tenders or the administrative approach to setting levels be technology neutral or technology specific?**
- **How should the different costs of each technology be reflected? Should there be a single contract for difference on the electricity price for all low-carbon and a series of technology different premiums on top?**
- **Are there other models government should consider?**
- **Should prices be set for individual projects or for technologies?**

In setting administratively determined support levels, we favour a banded technology approach, at a technology level as opposed to a project level, with the possible exception of nuclear projects. This has worked well in the past e.g. in the case of the banded Renewable Obligation. Given that the costs and risk profile associated with each technology is markedly different, we believe support levels should be technology specific to deliver the optimum energy mix whilst ensuring security of supply at an affordable cost. However, care must be taken when setting values, to ensure the levels set are sufficient to encourage the necessary investment and deployment. Setting tariffs at the right level for all low carbon technologies will help ensure that an unsustainable level of deployment of any one technology does not occur.

In the case of nuclear developments, it would be sensible to give further consideration as to the case for setting the FIT on a project by project basis. The advantage of this approach would be the ability to take account of project specific economics in detailed discussions held between Government and developers. The disadvantage will be the difficulty of the procurement process that a plant by plant process would entail.

In all cases, it will be important that the positions of all significant developers of a technology, and not just those whose plans are most advanced, are taken into account in setting the FIT terms. For long lead time projects, it may be appropriate to consider parameterising the tariff to take account of such issues as construction industry indices, steel prices etc. during the construction period. It will be important that any first of a kind allowance for nuclear or round 3 offshore wind applies to the first reactor or windfarm built by each consortium.

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

As discussed above, there are unlikely to be sufficient viable sites which are not required to proceed in the public interest to make an auction approach workable.

- **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?**

In the event of impending over-deployment of a technology, the Government could give appropriate notice that the Feed in Tariff would cease to be available or be reduced for new projects. The notice period would need to be long enough to protect developers who had paid significant sums to prepare projects for approval. This would address this concern as effectively as auctions without the risk of stifling development.

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

Whatever changes take place, it is vital that the importance of the market in governing the electricity industry is maintained. In our view, not only is the market the best incentive to efficiency along the production chain – from designing and building plant through to fuel procurement and the supply business – but it provides the best approach to efficient real time dispatch.

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

Setting separate yet adequate and sensible tariffs per technology will help ensure the market is not distorted in favour of any one technology. Ensuring cost evidence is built into any model of administratively set prices and that these prices are updated on a periodic basis (with grandfathering built in) should also help to minimise the opportunity for generators to profit excessively from any support mechanism.

The way to avoid market distortions on a capacity mechanism is to have a broad mechanism, not a targeted one.

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

It will not be possible to answer definitively whether the proposed reforms will increase risk or achieve greater investment certainty until much more of the detail is developed. Issues which will affect this balance include:

- The full details of the FIT/CFD system or any premium FIT alternative. The CFD system could promote certainty because of the legal status of a contract, but much will depend on how the strike price will be set and the other CFD terms
- The proposed capacity mechanism, which could clarify investment decisions for flexible thermal plant if applied broadly to all technically capable plant, but could create additional risk if targeted at a subset of the relevant plant
- The proposed EPS, which is likely to increase investment and political risk unless effective grandfathering at the point of the final investment decision for a new plant is entrenched in primary legislation
- The carbon floor price, which will impact investment decisions around thermal plant (though not low carbon plant because of the CFD system).
- The effectiveness with which the RO is honoured for existing and pipeline projects and the timeliness with which clarity is provided for the new system as well as the transition process
- Whether investors interpret the decisions (especially on the capacity mechanism and honouring the RO) as stranding past investments and therefore increasing the perception of regulatory risk for the future

Subject to these issues, we believe that EMR has the potential to provide additional certainty for investors.

It will be important for DECC to be able to state policy intent very clearly as we move through 2011, with sufficient detail on substance and timings, for the entire EMR package. Indeed, it will also be necessary to have similar certainty about issues such as transmission charging, which could affect a number of key investments.

Q35. Do you agree with the principles underpinning the transition of the Renewables Obligation to the new arrangements? Are there other strategies which you think could be used to avoid delays to planned investment?

We agree with the principles underpinning the transition from the RO to the new FIT arrangements. An orderly and structured transition period is crucial to ensure that investor confidence is maintained during this period and a hiatus in new development is avoided.

However, under the proposals, a new FIT system is envisaged as being in place as early as 2013/14; in the scheme of such large scale change, this is a relatively short timescale for implementation. If a new FIT system were delayed beyond 2013/14, then Government must keep the RO open for new projects beyond 1 April 2017. Projects expected to commission close to this period, will be near financial close around 2013/14, therefore they will require visibility that the RO will still be available to provide the required levels of support, in the event that a new mechanism is delayed.

Furthermore, if there is such a delay, band levels post 2017 must also be known in 2013/14 to assist developers in making an informed decision of which scheme to opt for (RO or FIT) during the transitional period. Without certainty and confidence of support levels under the RO post 2017 developers will not be able to take a reasonable view on the most appropriate system. This could lead to a hiatus in development, until such times as support levels under both schemes are known.

Q36. We propose that accreditation under the RO should remain open until 31 March 2017. The Government's ambition is 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 new RO;**
- **All new renewable electricity capacity accrediting after the introduction of the low-carbon mechanism but before 1 April 2017 should have a choice between accrediting under the RO or the new mechanism.**

In order to reduce the risk of an investment hiatus, and to allow developers to access and acclimatise to a new system before the RO closes, developers must be given the choice of whether to opt for the existing RO or new FIT mechanism. This is also important as otherwise the Government will feel a need to set the FIT to be less generous than the RO (to avoid developers waiting for the new system), only to find investment slowing, or indeed stopping, once 2017 arrives.

However, there are also a number of issues surrounding the transition period, which require clarity before investors can be fully comfortable, for example;

- The initial levels of support under a new FIT mechanism must be known as soon as possible after the new band review for the RO concludes (expected autumn 2011), to enable developers to make an informed decision on which scheme best suits their investment requirements, and therefore which scheme to opt to operate under. These initial FIT support levels can be updated after a couple of years, subject to the usual grandfathering, but it is important to have something in place in a timely manner to smooth the transition.

- Under the RO, although projects can apply for pre-accreditation, they are officially only accepted into the scheme from the point of full accreditation (which equals point of first generation). However, if a project's expected commissioned date is close to 1 April 2017, but it experiences delays, then the cut off date for receiving RO support will have been missed. In such cases there needs to be a clear and straightforward mechanism for the project to access the FIT mechanism, despite the fact that it had not done so at financial close. Alternatively, there could be an element of flexibility around the cut off period for RO support. A point of preliminary accreditation has been used in the past for eligibility under the RO. This precedent could be used for allowing projects that receive pre-accreditation by 31 March 2017 to qualify for ROCs subject to achieving full accreditation by say 31 March 2020.

Further, in relation to support for refurbishment, replacement and re-powering of existing plant, Government's response to the Renewables Obligation Consultation in 2010 (December 2010), advised that "it *would be more appropriate to consider this issue as part of the work on any new support mechanism introduced as part of the EMR*". However, it appears that this issue has not in fact been considered as part of the consultation proposals.

We therefore ask Government to provide clarity on how such investments will be treated under the EMR i.e. will they continue to be supported under the RO or will they be treated as new projects and have the option to obtain support under the new FIT mechanism? Similar uncertainties also exist for stations in the RO which add capacity in the future.

Q37. Some technologies are not currently grandfathered under the RO. If the Government chooses not to grandfather some or all of these technologies should we:

- **Carry out scheduled banding reviews (either separately or as part of the tariff setting for the new scheme)? How frequently should these be carried out?**
- **Carry out an "early review" if evidence is provided of significant changes 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 band reviews under the RO?**

We believe that the most appropriate treatment for technologies not currently grandfathered under the RO would be to move them into the new FIT scheme. These technologies will then be able to undergo reviews in line with projects of the same technology in the new scheme and maintain a level playing field.

Q38. Which option for calculating the obligation post 2017 do you favour?

- **Continue using both target and fixed headroom;**
- **Use calculation B (headroom) only from 2017;**
- **Fix the price of a ROC for existing and new generation.**

We think a hybrid approach to the RO – calculation B up until 2027 and then an equivalent fixed ROC or premium FIT thereafter – seems the best way to deal with the need to avoid disturbing Power Purchase Agreements in the next few years while avoiding unintended effects as 2037 approaches. Any fixed ROC or premium FIT, when implemented, should be at a price per ROC equivalent to the buyout plus recycle benefit available under 10% headroom at the time of implementation.

March 2011