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Dear Jonathan

Electricity Market Reform

Thank you for the opportunity to provide comments on the package of options for reforming the electricity market.

This response is provided on behalf of National Grid which owns and operates the high voltage electricity transmission system in England and Wales and, as National Electricity Transmission System Operator (NETSO), operates the Scottish high voltage and offshore transmission system. National Grid also owns and operates the gas transmission system throughout Great Britain and through our low pressure gas distribution business we distribute gas in the heart of England to approximately eleven million offices, schools and homes. In addition, National Grid owns and operates significant electricity and gas assets in the US, operating in the states of New England and New York.

In the UK, our primary duties under the Electricity and Gas Acts are to develop and maintain efficient coordinated and economical systems and also facilitate competition in the generation and supply of electricity and the supply of gas. Our activities include the residual balancing in close to real time of the electricity and gas markets.

Through our subsidiaries, National Grid also owns and maintains around 18 million domestic and commercial meters, the electricity Interconnector between England and France, the electricity Interconnector between England and the Netherlands and a Liquefied Natural Gas importation terminal at the Isle of Grain. We have also formed National Grid Carbon Limited which is a wholly owned subsidiary advancing the transportation and storage elements of the Carbon Capture and Storage (CCS) supply chain.

National Grid is generally supportive of the objectives of electricity market reform (EMR). In order to assist in the decarbonisation of other sectors, early large scale investment in affordable, secure and sustainable electricity infrastructure will be a priority. EMR and, as part of this, a carbon price support mechanism has the potential to encourage the necessary investment in appropriate, low-carbon technologies.

We are supportive of this package of measures in broad terms. Some of the individual elements do deserve to be looked at in more detail. We have addressed the detailed response to the consultation questions in an appendix to this letter; however a summary of our key points is as follows:

- we do not think that the case for the introduction of a capacity payment mechanism has been clearly made. More specifically, we have concerns over the significant market distortion potential of a targeted capacity mechanism. It is not yet clear whether changes to the existing market rules that would improve market signals to build capacity, have been sufficiently explored. Such changes could include cash out reform and/or a capacity obligation on suppliers;
- with respect to the perceived problem of a capacity shortfall, we note from the consultation this is an issue around 2020, but only based on certain key assumptions. For example, the target date to establish a fully interconnected and integrated European energy market is 2014 and yet there appears to be limited reliance on the ability to access capacity across EU borders via interconnectors. There is sufficient time to further assess the situation and see if alternative market solutions can work before introducing a capacity mechanism;
- further consideration is needed of whether there is an argument for different types of Feed In Tariffs (FITs) for different types of generation if the key driver is to increase certainty for investors of all types of low carbon generation. For example, for generation with an exposure to fuel costs (e.g. coal or gas CCS) the use of a Contract for Difference (CfD) may remove an element of the natural hedge (i.e. electricity prices are linked to gas and coal fuel prices) and therefore increase investor uncertainty. As such this type of generation may benefit from a premium FIT;
- the purpose of a carbon price support mechanism should be to give certainty of the EU ETS price trajectory, as agreed at a European level, but it should not be set substantially above this level in order to avoid "exporting" carbon emissions. It is also not obvious that underpinning the carbon prices materially above the EU ETS level, is necessary given that EMR sets out a package of changes one of which is FITs; and
- it is difficult to see a downside to applying an Emissions Performance Standard even if it is largely regarded as an unnecessary backstop.

We have addressed the detailed response to the consultation questions in the Appendix to this letter. If you wish to discuss this further, or have any queries regarding this response, please contact me or [redacted] or [redacted] ([redacted]uk.ngrid.com).

Yours sincerely

[By e-mail]

[redacted] **Regulation**

Appendix 1

Current Market Arrangements

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

Yes, it seems clear that, without government intervention, the market in its current form does not have the ability to deliver the low-carbon investment required to meet the UK's environmental targets. The arguments presented in this chapter are further backed up by the fact that several other European countries have made the decision to intervene in their markets in order to incentivise investment in low-carbon generation. Examples of this can be found in Germany, Spain, the Netherlands and Denmark, although it should be noted that some of these countries have also shown recent changes to their support for certain types of renewables with potentially damaging consequences for investors.

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

Yes, from the System Operator's point of view it is clear that the loss of a substantial amount of fossil fuel generation due to the Large Combustion Plant Directive (LCPD), the Industrial Emissions Directive (IED) requirements, coupled with a number of members of the nuclear fleet reaching the end of their lives will mean that an 'energy gap' will develop which will need to be filled. If this is done purely with intermittent and inflexible plant then there is a clear risk that the 'Expected Energy Unserved' (EEU) will increase if no action is taken. What is required is an incentive on the generation / supply market to keep the amount of EEU at an efficient level whereby the value of lost load is appropriately considered.

One area that does not appear to have been fully assessed when determining the future risks to the UK's security of electricity supplies is the role of demand-side capability and interconnection. It is an established view that increased interconnection with Ireland and mainland Europe can help with the intermittency issues posed by renewable (mainly wind) generation and so aid and support electricity security of supply. The ability and certainty to be able to rely on interconnection at times of GB system stress (e.g. low demand combined with high wind and nuclear running, or high demand at time of low wind generation) will be increased as we move to establish a fully interconnected and integrated European energy market which the European Commission aims to achieve by 2014.

Options for Decarbonisation

Carbon Price Support

The aim of the carbon floor price support mechanism should be to deliver a stable floor to the EU ETS price to give investor certainty against a crash in the price of carbon similar to that seen at the end of the first phase of the scheme. This would allow the future price of carbon to be fully accounted for as part of investment decisions. However, we are concerned that the carbon price support mechanism could create an incentive to import electricity to GB, to the extent it creates a price materially above the EU ETS price. This may lead to higher carbon emitting flexible generation plant in the UK closing earlier, whilst similar generation plant in neighbouring member states enjoys a longer operating life. Such flexible generation plant is important in the short-term, for security of supply, until lower carbon emitting generation investment can be made to replace this plant. We therefore feel the purpose of a carbon price support mechanism should be to give certainty of the EU ETS price trajectory, as agreed at a European level, but that it should not be set substantially above this level in order to avoid "exporting" carbon emissions. Taxation rates are always subject to uncertainty and change and, as such, cross party support for a carbon floor price support mechanism may deliver some investor certainty if delivered through the tax system. We also feel that there should be a continued push to reform the EU ETS such that it can provide a stable, and predictable price at an appropriate level, thereby making a carbon price support mechanism redundant.

It is also not obvious that underpinning the carbon price materially above the EU ETS level is necessary given that EMR sets out a package of changes one of which is Feed in Tariffs. It is important to note that the decarbonisation of UK generation is not about the amount of higher carbon capacity generation in existence, but about how much of it is used. As more low carbon, low marginal cost plant is built, supported by Feed in Tariffs, the resulting wholesale spot prices will reduce the utilisation of higher carbon generation plant. The optimal result is decarbonisation with security of supply, in that more low carbon plant is built but that flexible higher carbon plant stays available to generate at progressively lower levels of utilisation.

Feed-in Tariffs

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

The assessment appears to be thorough and impartial. From the perspective of a transmission company, there is not a large difference between the models. However, the operation of the system is made less costly if generation is not incentivised to run in the absence of demand. The factors surrounding the ability of nuclear plant to be flexible is mostly governed by technical (specifically safety case) considerations so policy incentives are not likely to make a material difference. However, with wind, the System Operator currently has to pay generators a very high price (to compensate them at least for the loss of ROCs) in order to reduce their output (at times of system constraints or low demand). This is due entirely to the manner in which the current ROC mechanism incentivises plant to generate irrespective of demand levels (either local or national). It will be important that the cost of compensating low carbon generators unable to run, should relate to the value of the CO2 emissions that could have been avoided had there been adequate storage or network capacity available to allow the low carbon generation to have been utilised, either at a different time or in a different place.

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

It is important to maintain some link to the market to ensure an efficient behaviour (and therefore relatively lower balancing costs) which means that a fixed FIT is inappropriate except for smaller generators (i.e. less than 10MW). The benefits in terms of practicability offered by the premium FIT are clear to see. However, the main rationale for introducing FITs is to introduce increased certainty for investors and the primary linkage to wholesale power prices acts against this (exposure to gas prices would lead to increased investor uncertainty). Therefore, FITs with CfD appear to offer the best balance between investor certainty (and therefore reduced cost of capital) and exposure to market signals for generation with no exposure to fuel costs. This does assume that the CfD doesn't create any perverse incentive for low carbon generators to run regardless of the demand level, i.e. completely remove the short-term price signal. As further detailed in our response to question 10, there is a need for a market reference price with enough liquidity in order to achieve a credible reference price.

For generation with an exposure to fuel costs (e.g. coal or gas CCS) the use of a CfD may remove a natural hedge (i.e. electricity prices are linked to gas and coal fuel prices) and therefore increase investor uncertainty, as such this type of generation may benefit from a premium FIT.

In summary there appears to be an argument for different types of FITs for different types of generation if the key driver is to balance certainty for investors with incentives for efficiency for all types of low carbon generation.

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

The UK electricity market has a fairly successful history of ensuring that demand is met at all times at the lowest possible cost. If it were not for the need for the generation to be low-carbon, this record would probably continue. This is because the majority of generators would be either coal or gas-fired for whom the price risks are largely linked to the prices of primary fuel sources. These risks can be suitably hedged, an action which is most appropriately managed by the generator or supplier.

However, as the need to reduce carbon emissions increases, and in the absence of a stable high carbon price, there develops an increased need for intervention in energy policy. This leads to a situation in which an increasing proportion of generation on the system moves away from relatively high variable cost-based generation like coal and gas, to high fixed cost-based generation like nuclear and wind. With technologies such as these, investment risk is less dominated by fuel costs but instead is largely capital cost with significant regulatory risk associated with the level of the cost of carbon (which is ultimately determined by governments through various market interventions). In this circumstance, there is an advantage to transferring the risk (due to the future level of carbon price) from the generator or supplier to the Government since it is the Government that is best able to manage this risk. However, future gas prices will still need to be taken into consideration when deciding whether or not to invest in low-carbon generation in some of the scenarios and it can therefore be a disadvantage if the investment risk moves entirely from industry to Government. The key issue is for the risk to be carried by the parties best able to manage that risk. In the case of a risk that no one can effectively manage then this is best carried by Government / end consumer.

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

The main operational decisions that the price signal incentivises is that generators produce electricity when suppliers require it (i.e. it provides an incentive for generation to meet but not exceed demand as real time is approached). If this signal is removed (e.g. via a fixed FIT) and generators are incentivised instead to generate at maximum output at all times (particularly if, as in the case for wind, the cost of fuel is free), the role of the system operator and associated costs are increased hugely. One of the benefits of New Electricity Trading Arrangements (NETA), introduced in 2001, over the old Pool system is that the market is incentivised to efficiently 'self-balance'. The efficient operation of the market currently relies on market participants basing their operational and investment decisions on both current (i.e. spot and prompt) and future (i.e. curve) wholesale prices. The introduction of the Renewable Obligation Certificate in 2002 means that we now see an increasing level of generation that does not respond to short-term price signals (e.g. negative imbalance prices). In a high wind output situation when we have to constrain off some low carbon plant (wind / hydro / nuclear) then we should still get a price signal based upon the cost of carbon. Such a price signal should give investors a signal to build storage or interconnectors so that the low carbon generation can be used to replace high carbon generation at another time (i.e. via storage) or another place (i.e. via interconnection).

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

This question is not applicable to National Grid.

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

This question is not applicable to National Grid.

9. What impact do you think the different models of FITs will have on different types of generators (e.g. vertically integrated utilities, existing independent gas, wind or biomass generators and new entrant generators)? How would the different models impact on contract negotiations/relationships with electricity suppliers?

This question is not applicable to National Grid.

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

The existence of a market reference price with enough liquidity is essential in order to achieve a credible reference price to provide the benchmark against which CfD will be paid. Currently within the Balancing and Settlement Code a Market Index Data (MID) is used for the calculation of the Reverse Price for each Settlement Period, which reflects the price of wholesale electricity in the short-term market. We believe this price could be used as a reference price.

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

For the System Operator, the likelihood of increased low-carbon generation connecting onto the network brings with concern over the costs associated with negative bid prices at times of low demand/high wind output. This is because, under a regime whereby intermittent low-carbon generation receives a tariff for each MWh generated (i.e. based on output), the level of tariff is directly reflected in the bid price offered by the generator. This means that the costs of balancing the system become much higher as the penetration of intermittent generation increases. As highlighted earlier, the price signal should give investors a signal to build storage or interconnectors in order to fully utilise the renewable generation. However given that these costs (i.e. Balancing Services Use of System or BSUoS) are likely to constitute a material number over the length of a FIT scheme, they should properly be reflected in any cost-benefit calculation.

Employing a FIT which is paid on availability rather than output removes this balancing cost as the generator has no justification for setting a negative bid price. However, in addition to the potential benefit the price signal brings, setting the FIT based on availability means that there is no incentive for generation load factors to be optimised (i.e. a generator with a load factor of 0.2 would receive the same benefit as one at 0.4 if they had the same maximum output capacity). This effect can be mitigated to a certain extent by applying a premium FIT based on availability as the generator has a natural incentive to generate as a result of the wholesale price on offer. However, all things considered, basing the FIT on output is the most appropriate mechanism.

Finally, in order to encourage a generator to contract their output and, avoid a situation whereby a generator simply spills their output and receives income via imbalance prices, it may be sensible to link FIT revenue to having a contracted position for the output.

Emissions Performance Standards

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

There remains considerable doubt within the industry as to whether an EPS is necessary for the UK given the effects that a carbon price support mechanism will have on a technology already under threat from increasing carbon prices. There is also doubt as to whether a new-build coal station would be able to get through the UK planning process in light of the high profile opposition to the recent coal generation proposals. However, despite this, if gas prices were to increase dramatically the picture could change and the viability of unabated coal could again come to the fore. The EPS would both prevent unabated coal from being built and also act as an incentive to accelerate developments in CCS technology. As an alternative to EPS, the government power station consenting policy (section 36 process) could be used.

In terms of security of supply, it is hard to imagine that preventing construction of new coal plant will increase the levels of EEU as this plant will likely be replaced by unabated CCGTs. Therefore, it is only in a situation where gas supply is dramatically reduced when this becomes a problem due to an over-reliance on a certain type of generation. The likelihood of gas supply shocks is becoming ever less likely due to the variety of different supply sources (i.e. less reliance on mainland Europe due to Norwegian link and LNG terminals) and a similar risk could equally be envisaged for coal supply due to the reduction in domestic supply sources and vastly increased demand from countries such as India and China.

It is difficult to see a downside to applying EPS even if it is largely regarded as an unnecessary backstop. In addition, it should provide support for CCS development by setting out a clear glide path for low carbon generation performance which should allow clean coal to continue its role of providing diversity in the UK electricity mix.

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?

The higher limit of $600gCO_2/KWh$ is the more appropriate of the two levels as the idea of granting exemptions from demonstration projects (as has been suggested if the $450gCO_2$ limit is applied) may appear to discriminate against any future CCS ventures operating commercially. There is always the opportunity to reduce the limit at a later date after the CCS technology has been commercially proven with appropriate grandfathering (as detailed further below).

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?

From a security of supply point of view it is evident that applying the EPS to existing plant runs the risk of exacerbating the problems caused by the early closure of a number of flexible generators by the European emissions directives (LCPD and IED). This is because the decision to invest in order to opt-in to the IED is likely to be marginal and the added regulatory risk could easily cause the few stations considering opting-in to the IED to instead opt out. As the industry moves through the transitional stages towards decarbonisation there will be a squeeze on plant margins in the early-2020s. Looking at the graph shown in Figure 10 of the consultation document, it is clear that the existing coal generation is instrumental in maintaining a suitable plant margin at this pinch point. It therefore follows that applying the EPS to existing plant would directly act against the proposal to employ a capacity mechanism with the aim of keeping this plant available and so reduce the overall credibility of the regulatory regime.

As a regulated company, National Grid believes strongly that credible measures taken to mitigate future regulatory risk (and thus lower the cost of capital) are vital in a sector which requires large volumes of capital investment in long lived assets. Grandfathering at the point of consent is therefore important in ensuring that investment in new plant equipped with CCS technology is not deterred by future regulatory risk. The same applies to grandfathering of ROCs and achieving cross-party consensus on the carbon price support mechanism.

If the decision to grandfather has been taken, it is important to note that the reason for doing this is to increase investor certainty so as to ensure that the new power station is built. Therefore, it would seem perverse to then erode this investor certainty by applying a short economic life to the power station. In order to set an appropriate economic life for relevant power stations by which to apply the EPS, a possible method may be to consider the length of any FIT that has been awarded to the station (assuming that new CCS plant will be eligible for government support).

In any case, past 2030, it is increasingly unlikely that a scheme such as the EPS will be necessary as the dominating factor should be the EU ETS price of carbon. This makes the risk of power stations using their grand-fathered EPS as an excuse to continue generating at a high EPS very low (rather than any lower levels applied in subsequent EPS limits at newer plant).

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

In order that the objective of the EPS is achieved, it is important that any potential loopholes in the proposal are closed. Allowing existing plant to extend their life indefinitely by making piecemeal upgrades could be one such loophole and, as such, the EPS should be extended to prevent this.

There are difficulties in implementing such an approach in practice because, as mentioned above, it is important that generators which are considering investing to meet the requirements of the IED are not deterred from doing so. This means that a clear and unequivocal framework must be established to both prevent loopholes in the proposal and also to reassure existing coal generators that further restrictions will not be made in the future. This should be kept as simple as possible and be applied from the same date as the EPS. As highlighted in the previous response, the rising EU ETS price of carbon should drive the desired behaviour in any case.

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

This seems appropriate. As long as EPS is grandfathered there is no reason why its level cannot be reduced for new plant as CCS technology matures and becomes more commercially viable.

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

This question is not applicable to National Grid.

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

This appears to be a sensible stance bearing in mind the uncertainty that is likely to exist in the market over the coming decade and provides necessary capacity with low levels of utilisation of higher carbon generation. It should be noted however, that in order to accommodate the additional output, it would require additional investment in the network and connection.

Options for Market Efficiency and Security of Supply

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

The pros and cons of introducing a targeted capacity mechanism are clearly set out in the consultation document. The benefits can be seen as guaranteeing a capacity margin and, doing so at a lower cost of capital. The drawbacks are:

- central buyer decisions: a central buyer whose concern is security of supply is less likely to invest in new technology and innovation which also may be cleaner and more sustainable. A market based alternative would enable companies that specialise in risk management to make the efficient trade off between procuring demand side response, storage, interconnection, energy efficiency, and additional generation.
- the need for a central decision on the level for a capacity margin;
- can a central body get this decision right, in particular a central buyer whose concern is security of supply is likely to over procure with attendant costs for consumers.
- effect on peak prices: in the targeted model there would be a need to feed in the capacity payments to the cash out prices in order to avoid the market signal not being lost to market participants who do not rely on the capacity payment;
- slippery slope effect: should the price signals be weakened or the probability of plant being utilised be reduced as a result of a capacity mechanism then there is a risk that market

participants will not build generation, storage, interconnection or demand flexibility unless they receive a capacity payment. A capacity mechanism that is initially designed for peak capacity could over time increase as the market signals are distorted, thereby placing an ever greater requirement on the central body to procure capacity;

- paying twice: the potential inefficiency of trying to maintain imbalance price signals with a capacity mechanism. As highlighted above, there is a need for a reflective cash out price which if correctly targeted should encourage investment and therefore potentially lead to a situation whereby both the market and a central buyer provide the capacity;
- investment hiatus: the creation of a capacity mechanism may make the issue of a lack of capacity self fulfilling, i.e. generators choose to wait before investing as they wish to see the impact of a capacity mechanism first; and

We feel there is a lot to sort out before implementation could be achieved effectively. Some of these issues appear difficult to fix, for example how to avoid the "slippery slope" effect without maintaining peak prices which in turn leads to a real risk of paying twice.

With respect to the perceived problem of a capacity shortfall, we note from the consultation this is an issue around 2020 but only based on certain key assumptions. For example, the European Commission target date for establishing a fully interconnected and integrated European energy market is 2014 and yet there appears to be limited reliance on the ability to access capacity across EU borders via interconnectors. This is particularly important in relation to wind, as at a local level the capacity benefit is low (due to the probability of anticyclonic systems bringing cold, still, weather conditions over GB), but over a wider area (i.e. Europe) the capacity benefit of wind could be increased due to geographic diversification. We also note that it takes around 3 years to build a CCGT and therefore it may be expected that no commitment to build such generation is clear at this stage (i.e. there may be no commitment to build such plant until 2016/17).

It is important to note that the decarbonisation of UK generation is not about the amount of higher carbon capacity generation in existence, but about how much of it is used. As more low carbon, low marginal cost plant is built, supported by FITs and a carbon floor price, the resulting wholesale spot prices will reduce the utilisation of higher carbon generation plant. The optimal result is decarbonisation with security of supply in that more low carbon plant is built but that flexible higher carbon plant stays available to generate at progressively lower levels of utilisation, providing the necessary capacity, funded by sharper imbalance prices. Whilst this may provide a cost effective way of achieving a capacity margin there is a clear interaction with IED.

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

We remain to be convinced of the need for a capacity mechanism for the reasons set out above, and specifically we are clear (again for the reasons given above) that a targeted capacity mechanism would be inappropriate. It is not yet clear that the market will not build sufficient capacity or that changes to the existing market rules that may help have had sufficient time to take effect. Such changes to market rules include cash out reform and/or a capacity obligation on suppliers. We note Ofgem is intending to review the cash out arrangements and feel this should be done at the earliest opportunity if it is to be developed as part of an alternative solution to a capacity mechanism. There is sufficient time to see if sharper market signals work before considering the introduction of a capacity mechanism.

We note the consultation makes reference to a number of capacity mechanism examples. Perhaps the closest to a targeted capacity mechanism is the Peak Load Reserve mechanism in Sweden. We note here that the Swedish Energy Markets Inspectorate has on request by the Swedish government investigated the possibility of abolishing the peak load system in favour of a pure market solution. The conclusion in the report submitted to the Government in December 2008, was for a successive transition to a market solution during the period 2011-2020. We also note that NordREG, the Nordic Energy Regulators, in a recent assessment of the peak load arrangements share a number of our concerns, for example "...the existence of peak load reserves decreases the incentives for the market participants to prepare themselves for peak load situations."[1]

Within the consultation document a number of references are made to STOR. It should be noted that the key difference between STOR and a capacity mechanism is that STOR is utilised after gate closure and, to a large extent, does not impact the market incentive (delivered via imbalance charges) to efficiently balance at gate closure. STOR is an energy product (i.e. not a capacity product) and is used by the system operator to manage generation failure or demand forecast errors beyond gate closure where the market is unable to respond. A capacity mechanism directly interacts with the market incentive to efficiently balance at gate closure.

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

In an efficient and perfectly competitive market, the wholesale electricity price reflects the price of the marginal unit for each settlement period. Each unit prices itself according to its variable operating costs and an expected output level to recover its fixed costs. The introduction of a targeted capacity mechanism could mitigate the risk of fixed cost recovery by generators, thus causing their price to be a pure reflection of their variable costs. Should the targeted generators remain players in the wholesale electricity market (as opposed to being only utilised as a last resort by the system operator), the capacity payment may have the effect of interfering with the merit order of generators, thus impacting on the wholesale electricity price.

22. Do you agree with Government's preference for the design of a capacity mechanism:
• a central body holding the responsibility;
• volume based, not price based; and
• a targeted mechanism, rather than market-wide.

For the reasons articulated above, we prefer a market based approach (e.g. sharpening of imbalance prices). We see particular issues with a targeted mechanism.

A key justification for a capacity intervention is to remove the uncertainty which is hampering investment in flexible generation capacity. However, introducing a capacity contract mechanism to remove this uncertainty would be an expensive solution which impedes the market from delivering capacity in the most economic manner. If Government or regulatory intervention dampens "spiky" prices then the price spike will never arise that will justify the extra investment required in generation, storage, demand-side or interconnection. We think that the following package of measures could act as an alternative to a targeted capacity mechanism:

- market supervision: a requirement to report on forward looking capacity levels.
- imbalance prices: existing "missing money" issues due to imbalance charging and reserve cost recovery should be addressed by sharpening imbalance prices. In particular, payment to a pseudo price for lost load as a result of voltage reductions or rota disconnections should be used to expose market participants to the consequences of insufficient capacity leading to unsupplied energy.

We would wait to see whether these measures deliver the necessary certainty to the market before moving towards implementation of a capacity mechanism. In the past, National Grid has suggested imbalance charging (including reserve pricing) modifications, but these have not been implemented due to concerns that price signals may not accurately communicate the market fundamentals. These proposals should be revisited in the light of emerging concerns and, for its part, National Grid would be happy to re-present its analysis of how capacity and flexibility issues might influence future price volatility, so that the market can decide what price hedges are most appropriate.

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[1] https://www.nordicenergyregulators.org/upload/Reports/Peak%20Load%20-%20final%20(2).pdf

We accept the need for a FIT for low carbon generation (e.g. wind) due to the high up front cost and low marginal cost. However, this market failure does not hold true for today's flexible plant (e.g. gas plant) which is low up front cost, higher marginal cost and we would expect such plants to pay-back over a shorter period. As such, the need case for a capacity payment is not clear.

However, if a capacity mechanism is to be implemented, we would favour a volume-based market-wide approach. This would probably need to be managed by a central body but it should be recognised that such a central approach brings with it a systemic risks of making the wrong decisions on the capacity level and mix which is less likely when a range of players are making their own security of supply judgements.

An alternative to a market wide capacity mechanism is a supplier obligation. This would require suppliers to demonstrate they have sufficient physical generation (which could be via contracts) to meet their supply obligations. This would require a body to assess how suppliers are meeting their obligations and penalties for failure (e.g. a "pseudo cost" of new flexible capacity). The requirement to demonstrate a physical obligation may place a barrier to entry and favour vertical integration. The benefit however is that a supplier obligation would provide certainty, and being a more market based approach, would bring with it market efficiencies. Indeed a supplier obligation could be seen as applying equally well to decarbonisation, i.e. suppliers could be given an obligation in terms of the carbon content of energy.

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?

A capacity mechanism would reduce the market incentive to invest in demand-side response, storage, interconnection, and energy efficiency as a number of these technologies rely on volatility in market prices (a key part of an efficient market) which a capacity mechanism would probably dampen. Furthermore, since the decisions of what capacity to procure in a capacity mechanism will be on a central buyer, it will be up to them to procure suitable products. The market based alternative would enable companies that specialise in risk management to make the efficient trade off between procuring demand side response, storage, interconnection, energy efficiency and additional generation. Indeed a supplier will already have the direct relationships with its customers, making procurement of demand side response more efficient than via a central buyer.

The key purpose of the proposed roll-out of SMART meter technology is to give improved signals to the demand side and opportunities for demand automation. Central planning of capacity via demand response and small scale generation is unlikely to be feasible and can be better incentivised through accurate wholesale energy price signals.

24. Which of the two models of targeted capacity mechanism would you prefer to see implemented:
• Last-resort dispatch; or
• Economic dispatch.

Last resort dispatch appears the only mechanism by which to minimise market distortion and avoid a situation whereby increasing levels of generation is procured via a capacity mechanism. Economic dispatch with fully reflective cash-out prices, still raises the risk that generation requiring a "peaky" payment does not receive it as the System Operator dispatches other more cost effective generation (but only because it receives a capacity payment) thus reducing its opportunity. However, last resort dispatch also brings with it the real risk of paying twice.

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

Under the Connect and Manage regime, until system reinforcements can be completed, there is a real risk of network constraints (over and above those of an efficient network). It would therefore seem sensible that the capacity that is being procured for system security can actually be utilised when needed. A locational element to capacity pricing could ensure this. This would also ensure that the lead time to build new generation capacity in time for a forecast 'margin squeeze' would not have to include transmission works and the possible delays that could ensue, due to delays in obtaining planning permission.

It is worth noting that constraints which normally bite in high wind scenarios are not so much of an issue when considering capacity mechanisms. This is because the plant incentivised by the capacity mechanism is most likely to be dispatched in low wind scenarios. In fact, locating the generators built under a capacity mechanism near to areas of high wind may in fact be beneficial to system security.

Analysis of Packages

26. Do you agree with the Government's preferred package of options (carbon price support, feed-in tariff (CfD or premium), emission performance standard, peak capacity tender)? Why?

We are supportive of the review and see its primary objective to ensure that there is sufficient renewable/low carbon solutions connected to enable us to meet UK emission targets, whilst ensuring sufficient generation is connected in total to ensure security of supply. Whilst we agree this can be achieved via a FIT, carbon price support that provides a floor to the EU ETS price trajectory and an emission performance standard, we are not convinced, at the present time on the need for a targeted capacity mechanism.

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

The alternative package substitutes CfD for a premium FIT. As stated earlier in our response there may be a case to offer both, as it does not appear to be the case that one size fits all, particularly in the case of CCS and CfD. For generation with an exposure to fuel costs (e.g. coal or gas CCS) the use of a CfD may remove a natural hedge (i.e. electricity prices are linked to gas and coal fuel prices) and therefore increase investor uncertainty, as such this type of generation may benefit from a premium FIT.

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?

Generally, decarbonisation of the electricity sector will lead to a significant increase in system complexity. For example, we know that an increase in levels of wind generation leads to an increase in the scale and volatility of power flows across networks (as has already been seen in Germany and other regions within Europe). We therefore see our transmission network requiring investment in directly controllable transmission assets (HVDC inks and Quad Booster Transformers for example) to be able to facilitate connection of renewable energy sources and to manage flows effectively. In turn, we see a need to invest in control tools to align our capability with the real time operational challenges of the future network. We are currently engaging with stakeholders to help define our future investment plans. The outcome of EMR will need to be reflected in these plans.

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

Each of the elements of the package clearly do interact. The level of the carbon price support interacts with the FIT to the extent the higher it is the less there is a need for a FIT and vice versa. EPS and the carbon price support interacts to the extent the EPS may not be necessary with a sufficiently high and predictable carbon price. Finally, any cash out reform interacts with the need for a capacity mechanism to the extent that a sharper cash out signal will encourage investment in new generation, together with demand side measures, storage and interconnectors.

Implementation Issues

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

The biggest risk is a failure to provide a clear way forward as this is likely to lead to an investment hiatus. We therefore feel a clear way forward should be given at the earliest opportunity, including instrument design, and that sufficient time should be provided to implement the new mechanisms.

31. Do you have views on the role that auctions or tenders can play in setting the price for a feed-in tariff, compared to administratively determined support levels?
• Can auctions or tenders deliver competitive market prices that appropriately reflect the risks and uncertainties of new or emerging technologies?
• Should auctions, tenders or the administrative approach to setting levels be technology neutral or technology specific?
• How should the different costs of each technology be reflected? Should there be a single contract for difference on the electricity price for all low-carbon and a series of technology different premiums on top?
• Are there other models government should consider?
• Should prices be set for individual projects or for technologies?
• Do you think there is sufficient competition amongst potential developers / sites to run effective auctions?
• Could an auction contribute to preventing the feed-in tariff policy from incentivising an unsustainable level of deployment of any one particular technology? Are there other ways to mitigate against this risk?

At a high level, an auction is most likely to provide the target level of low carbon generation required at the most efficient cost. However, when considering the detail there are numerous issues that may lead to the auction itself failing to deliver the targets: for example when to tender. If a party is allowed to tender before they have a fully developed proposal there is a risk that projects fail to turn up. If a party is obliged to deliver, there is a risk that projects will not tender as the costs are too high against the risk of failing in the auction. In principle this problem could be solved by allowing projects yet to be built to take part in the auction and, should they be successful, they would make a deposit high enough to penalise them for non-delivery (and that could be freed up in steps as the project advances) but low enough as to not create a "winners curse".
If the auctions of FITs are going to be technology-specific, then auctions are likely to be more suitable for relatively mature, low entry barrier technologies, like wind than they would be for new technologies or for nuclear.

The problems associated with either setting a price administratively or conducting auctions could be solved, at least at one level, by a supplier obligation approach which would transfer the problem of selecting the cheapest way to deliver a given amount of decarbonisation to suppliers.

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

We have nothing further to add to our previous responses.

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

We have nothing further to add to our previous responses.

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

Yes.

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

This question is not applicable to National Grid.

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

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

This question is not applicable to National Grid.

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

- **Carry out scheduled banding reviews (either separately or as part of the tariff setting for the new scheme)? How frequently should these be carried out?**
- **Carry out an "early review" if evidence is provided of significant change in costs or other criteria as in legislation?**
- **Should we move them out of the "vintaged" RO and into the new scheme, removing the potential need for scheduled banding reviews under the RO?**

This question is not applicable to National Grid.

38. Which option for calculating the Obligation post 2017 do you favour?

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

This question is not applicable to National Grid.