Response to DECC Consultation on Electricity Market Reform, December 2010

Executive Summary

- The Association welcomes the Government's recognition of the issues surrounding investment decisions in the electricity industry and its efforts to address them. We wish to see encouragement of a robust, competitive and liquid wholesale electricity market, which should provide a reliable and credible wholesale price where the investments required to meet the Government's energy policy objectives are fully rewarded.
- We are mindful of the impact on consumers. In their interests, the Government must demonstrate that the chosen measures are the most cost-effective in delivering emissions reductions with security of supply. As soon as practical, in order for consumers - who will ultimately pay for these initiatives - to fully appreciate the financial impact of the proposals, it is essential that the economic rationale and financial impact is clearly articulated and understood.
- We note that, in order to achieve the Government's decarbonisation targets, electricity is to assist in the delivery of an overall 80% reduction in CO_2 emissions by 2050 set against a 1990 baseline. The Government must ensure that its decarbonisation efforts are not undermined by the substitution of low carbon electricity with fossil fuels. We consider that Government should assess the value of applying incentives uniformly across all energy sources and uses.
- Members have different views on the most appropriate financial support mechanism for low carbon technologies. Whichever model of feed-in tariff the Government decides to implement, it is essential that the new mechanism is more effective than existing mechanisms in delivering the UK's low carbon and renewable energy ambitions. Many crucial details about the operation of either of the Government's preferred forms of feed-in tariff are missing from the consultation document. The Association would be pleased to work with the Government to develop the proposals further and ensure that the new instrument functions as effectively as possible from the outset.
- Members do not consider at this point in time that auctions afford an appropriate degree of certainty for investors, particularly in the early days of designing a feed-in tariff. It is difficult to understand how

anyone could argue in favour of significant investment when there is no assurance that there will be a definite route to market.

- We consider the introduction of an Emissions Performance Standard to be unnecessary and premature. While it would prevent investment in unabated coal-fired plant, it would not provide any incentive for investment in other, low-carbon, electricity generation capacity.
- Members' views are divided on whether any capacity payments solution should be introduced at this stage in the development of electricity market reform. The targeted capacity payment approach may be flawed as currently proposed when applied to the UK electricity market and requires significant further examination. If introduced however, any capacity mechanism must be designed to minimise any distortions to the wholesale electricity price.
- The transition to the new arrangements must be carefully managed so as to retain investor confidence in the UK, with the transition path being set out in the forthcoming White Paper.
- Existing investments must be protected and the Government should consider carefully the potential unintended consequences of the proposed reforms on these projects and on all types of participant in the market.
- We urge HMG to seek early engagement with EU legislators to identify and resolve any conflicts between each element of the EMR proposals and EU legislation or policy.

About AEP

The Association of Electricity Producers (AEP) represents the many different companies, both large and small, that make the electricity upon which the UK depends. Between them, AEP members account for more than 95 per cent of the country's electricity generation capacity and embrace all generating technologies used commercially in the UK – coal, oil, gas, nuclear power and a range of renewable energy technologies. A list of our members can be found online at www.aepuk.com

General remarks

Durability and stability

We welcome the Government's principle of durability in developing the new arrangements. Stable market arrangements are essential to give companies the confidence to invest in the UK. We therefore encourage policy makers to strive to achieve a consensus across political parties on the electricity market reforms to reduce the risk of further changes to the arrangements in the next ten years. Increased Government intervention could mean increased risk for our industry. The industry has seen Government decisions regarding the Renewables Obligation unduly delay long-term investment. Investors have to be given the confidence that, having been encouraged to invest via Government-supported schemes, their investments will not be put at risk by changes to those schemes. This means that the Government should make a clear commitment to the protection and 'grandfathering' of such investments.

Should this be achieved, then we believe that this will go far to ensure we avoid any further investment hiatus. Early clarity is essential, together with a firm timetable of expected deliverables. If there is no clear response then the downside will be that projects are shelved or investment moved elsewhere. It is paramount, however, that any emerging policies do not adversely affect current projects already progressing along the development chain.

We acknowledge that there are issues around adequate levels of resource to ensure delivery of Government policy. We trust that DECC will be given access to additional resource to support what will be a period of intense activity following delivery of the Energy White Paper and that the industry will be invited to participate in the next phase of development and implementation. We must emphasise that realistic timescales should be applied to the introduction of new initiatives.

It is also important that we do not fall into the temptation to consider options which could encourage an element of 'scope creep'. The introduction of any market intervention should not be taken lightly and should therefore be kept at a minimum, should have clearly defined and understood objectives and be able to be monitored in such a way that will provide for clear, time-dated post implementation assessment for continued effectiveness and enduring relevance.

We are mindful of the impact on consumers. In their interests, the Government must satisfy itself that the chosen measures are the most cost-effective in delivering emissions reductions with security of supply. In order for consumers - who will ultimately pay for these initiatives - to fully appreciate the financial impact of the proposals, it is essential that the economic rationale and financial impact are clearly articulated and understood.

We need to understand better the scope for demand side response to assist with balancing the system and maintaining security of supply. This should include an understanding of the impacts on the future use of electricity which may be impacted by changes to building regulations and include an assessment of future fuel usage. In turn this will ensure that we set out credible expectations and clearly understand the impact on outturn wholesale price. We expect there to be a strong link to the work being undertaken on 2050 Pathways.

Devolved administrations
The Association recognises the current powers of the Scottish Government and the Northern Ireland Executive to determine levels of support for renewable energy. However, given that the electricity market operates across Great Britain we consider that support mechanisms should apply consistently across England, Wales and Scotland and we would therefore wish the Scottish Government to adopt the same support mechanism as in England and Wales.

Process

Process for developing this response

Acknowledging the importance and long-term impact of EMR, we have established an Electricity Market Reform Steering Group, drawing membership from across a representative group of our members. The group drew upon the expertise from within our individual Association committees to develop and recommend an approach to the several strands within the EMR proposals.

Process for developing a long term solution

Our hope is that the EMR work will provide clear, stable and achievable proposals that will demonstrate that the UK offers a credible and robust environment in which to invest. Whatever the conclusions of this review, there should be an assessment of whether a speedy and radical implementation delivers the best result, compared with an option which delivers a number of quick wins followed by slower, more evolutionary, change.

DECC will be aware that, for many years and with few exceptions, the Association has been consistent in its support of market principles and the importance of market-driven prices. Our members recognise that the Government is looking at a more interventionist approach to deliver and implement an enduring electricity regime to assist in the transition towards a low carbon future. Although the EMR presents the Association with difficult issues it is already clear that members want to see the encouragement of a robust, competitive and liquid wholesale electricity market, which should provide a reliable and credible wholesale price where the investments required in meeting the Government's energy policy objectives are fully rewarded. We have also stated consistently that, given a clear and stable policy and regulatory framework, the industry is capable of managing risk. How the increased level of central intervention is balanced to ensure that market based opportunities continue will be central to the success and ambitions of these far-reaching reforms.

Other matters of interest

The Association notes that the Committee on Climate Change has indicated that it would prefer there to be rapid deployment of low carbon plant ahead of any increase in electricity demand (arising from the decarbonisation of other sectors, such as transport) rather than allowing the market to determine the mix of generation to be built to fill a generation gap. The Government, however, should be conscious of the potentially negative outcome of a surplus of generation capacity being forced on to the system. Current levels of capacity compared with demand have led to wholesale prices being depressed and in the last decade, when generating capacity greatly exceeded demand, companies were put out of business. With existing and future investment in mind, careful consideration should be given to the possible impact on the Committee on Climate Change proposal and the mitigation of risk to investors.

We note that, in order to achieve the Government's decarbonisation targets, electricity is to play its part in contributing towards an 80% overall reduction in CO_2 emissions by 2050 set against a 1990 baseline. The Government must ensure that its decarbonisation efforts are not undermined by the substitution of low carbon electricity with fossil fuels. We consider that Government should assess the value of applying incentives uniformly across all energy sources to deliver emission reductions in the most efficient way.

The impact of European legislation and its application to the UK must not be underestimated and must be factored into consideration of the eventual EMR conclusions. We urge the Government to consider carefully the interactions between its proposals for EMR and EU regulations.

A number of the proposals raise issues in relation to EU legislation and policy. For example:

- Contracts for Difference (CfDs) are likely to be regarded as financial market instruments and would therefore be subject to EU financial regulation; in addition, CfDs for particular technologies could require State Aids approval. CfDs will have to be struck against a reference price, which raises questions about what form this will take in the reformed GB market and how it will fit with the target model for electricity markets which the EU is currently developing.
- Capacity payments do not figure in the target model and would presumably have to comply with the Third Package requirements on tendering for new capacity.
- CO_2 price support would have to be compatible with the EU ETS and Energy Taxation Directives.
- An Emissions Performance Standard (EPS) also needs to be compatible with EU law.
- Impacts of the Markets in Financial Investments Directive (MiFID) need to be considered.
- In addition, there is a number of emerging energy-related European codes due to begin development in the near future. DECC should be aware that early sight of a pilot connection code has caused widespread concern among our membership, given its radical and prescriptive nature.

In this light, we recommend that HMG should seek an early meeting with the European Commission to ensure that they view the likely approach as consistent with EU law and acceptable. It is important that the proposals are durable and provide stability, so it is essential that they are not open to challenge.

We find it difficult to assess the impact of the proposed reforms on market liquidity. While we support initiatives which deliver increased liquidity, we cannot see any specifics within the proposals which will promote this. Indeed for the CfD element of the proposals to work, liquidity is paramount. There is no "correct" level of liquidity, yet poorly considered design could actually result in reduced liquidity. We consider that additional focus on this area would be of benefit particularly around the development of liquid exchanges in longer-term options.

We are also aware of the Government's review of the future focus for Ofgem and we look forward to the outcome of that and clarification of Ofgem's future role and responsibilities with regard to electricity market reforms. This includes clarification of where current Ofgem initiatives such as Project TransmiT and review of market liquidity would be relevant to the outcome of these reforms.

Infrastructure investment is paramount in order for our members to get their product to market and to enable them to achieve lower carbon targets. We would question, however, whether it is appropriate to look towards public funding of interconnection. We currently find it difficult to fully assess the risks and rewards.

We note that the consultation does not make reference to interactions with the existing gas regime. We believe that it is important that once the direction and detail within the EMR proposals begin to move towards more firm proposals that the impact of intended and unintended consequences for gas is fully assessed.

We should like to emphasise that a timely and business-like planning process and significant grid investment remain vitally important if the transition to a low carbon electricity supply industry is to be achieved.

Next steps

This reform will be, in effect, the fourth set of trading arrangements (the Electricity Pool, New Electricity Trading Arrangements (NETA), British Electricity Transmission and Trading Arrangements (BETTA)) to be applied to the electricity industry since it was privatised and liberalised in 1990/91. The EMR consultation envisages the publication of a White Paper in the late spring of 2011 which is expected to include final proposals.

To date the process for the development of the enduring arrangements has not been clear. We have therefore made the assumption that in order to develop the finer detail of the overall design, it will be necessary to establish a programme of work similar to that undertaken during the development of NETA. If this is the case, our members would be happy to contribute their expertise via input to the various workstreams that we consider it will be necessary to establish.

It should come as no surprise that we seek a balance where the returns we might expect to see would be commensurate with the overall risks involved. In general, as an industry we look to mitigate the regulatory and policy risks that come as part of the overall design for business in our sector. For example, we would also expect to see improvements delivered in parallel with regard to planning.

We seek reassurance that provision has been made for sufficient resource within DECC to see this process through from this initial fact finding stage through to delivery and implementation of the EMR conclusions in a timely manner.

Finally, we note that the EMR needs to deliver what investors are looking for by way of a stable, predictable framework with rates of return that are commensurate with the risks associated with the provision of low carbon projects. This is a fundamental requirement to achieve a successful outcome.

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APPENDIX 1
Response to the Consultation Questions

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, the current market design is not equipped to deliver the required low-carbon investment. Ultimately, competition will provide the least cost solution. Bilateral and exchange-based trading should continue to offer the greatest benefits to consumers.

New investment incentives (such as the FIT mechanism)

- must promote investor certainty;
- must deliver the full value of the incentive to investors;
- must continue to promote a competitive wholesale market;
- must minimise cost to the consumer; and
- must ensure security of supply.

Clarity of enduring policy objectives is crucial.

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

DECC sets out its rationale for reform and highlights the range of challenges faced by companies considering investment in flexible plant against a background of increased low carbon capacity in Chapter 2 of the consultation document. While this is a promising start, of DECC's three objectives for the electricity system (Security of Supply, Decarbonisation and Affordability), the EMR proposals themselves are clearly geared towards achieving Decarbonisation[1].

The security of supply challenge (largely brought about as a result of the other policies and interventions) does not receive sufficient consideration. This is not just a "peak capacity" issue, but also one of the system's inherent ability to cope with wind variability on a large scale. Understanding and anticipating these challenges is critical to market design and essential to the facilitation of the low carbon transition. Risks to security of supply fall into two main categories: first, the excessive dependence on one type or source of primary energy and, second, the artificial creation of imbalances between patterns and volumes of supply and demand due to political objectives and targeted interventions. This important work is not adequately covered and, therefore, in our view the Government assessment is incomplete.

[1] This conclusion is reinforced by the binding assumption in all of the supporting analysis that EU Renewables targets and UK Carbon budgets will be met – irrespective of cost.

The current high level of policy and regulatory uncertainty may make the risk to security of electricity supplies more of a problem in the future because the economic case for investment in new CCGT capacity or in life-extension of existing capacity is not yet clear cut. This creates a more difficult environment in which to attract the investment needed to replace the large volume of plant closures expected over the next decade or more. When investors are confident that prices will rise to a level which will reward investment, the current market will respond to anticipated capacity shortages with new investment.

We consider that in order to deliver the flexibility needed as more intermittent generation enters the system towards the end of this decade, support may be needed for options that deliver that flexibility, such as existing CCGT and potentially new peaking units and enhanced demand side response.

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 Association notes that the Renewables Obligation (RO) has been successful in bringing forward renewable energy projects, with eligible generation increasing by more than 15 TWh since the scheme's introduction and a project pipeline now standing at over 20 GW in planning or awaiting construction/commissioning. If the RO is to be replaced with a feed-in tariff for renewables, the new mechanism must be more effective in delivering the UK's renewable energy targets.

We agree that it would be undesirable to implement a fixed FIT as this would remove a large proportion of the UK's generation capacity from any exposure to market signals.

Of the Government's lead options for the new support mechanism (either a premium FIT or a FIT with CfD), the premium FIT would build on the positive aspects of the RO, be familiar to investors, be reasonably simple to design and administer, and would leave power price risk with energy companies in keeping with the UK's current market-orientated approach. However, the level of premium in the premium FIT may need to be higher to recompense developers for taking this risk. The FIT with CfD is, in principle, likely to lead to greater reductions in market risks associated with new low carbon investment than a premium FIT, particularly for new nuclear power or CCS plant, and it should therefore make it easier to attract new forms of investment. This would, however, need to be balanced against the increased complexity of the mechanism, particularly for renewables where there is already an established and well-understood support mechanism.

A CfD model, unlike a full FIT, would allow plant to continue to participate in the wholesale market. However, as CfDs covered an increasing proportion of generation, there would be significant effects on how the market trades given that players would wish to hedge their position around a reference price. Whether the Government's aim of maintaining a functioning wholesale market and efficient dispatch could be achieved would depend on how this mechanism is implemented in detail. With liquidity being essential to the functioning of a CfD FIT, the Government would wish to assure itself that all types of generation still have an equal incentive to trade their output in order to maintain the influence of market forces in electricity.

A premium FIT would have the least effect on the traded market. However, the Government would need to be mindful of the unintended consequences of its package of reforms, particularly its impact on wholesale power prices and the implications for generators that would remain exposed to these price variations, either existing investments or new ones under a premium FIT.

We note that a contractual mechanism would be less subject to political risk than one which could be changed under legislation and is therefore likely to be more bankable. Investors would need to have confidence to enter into contracts with the counterparty. If the agency acting as the counterparty acted in an unpredictable way, this would discourage investors from developing projects to the point at which they would be eligible for a contract. It could also open the way to a policy framework whereby the Government was effectively dictating what projects would come forward and where. These risks could be addressed through careful design of the framework and the role of the agency.

None of these mechanisms removes development, construction and operational risks which are major factors associated with new low carbon investments. Regardless of the exact form of support mechanism, returns still need to be adequate to cover these risks and attract investment to the UK.

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

Members have different views on the best mechanism for supporting low carbon investments, in particular which of the Government's lead options – a FIT with CfD or a premium FIT – it would be preferable to introduce.

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?

A CfD-based system, is likely to reduce the cost of capital, though this brings with it different exposure for customers. If global commodity prices fall, under a CfD system customers will still have to pay a high price for generation under the support mechanism and could be paying more than others internationally. If global commodity prices rise, on the other hand, they will be better placed than customers internationally. Overall prices to customers should become more predictable.

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?

Robust signals from efficient price formation and price discovery are fundamental to the functioning of the market. A robust electricity market price (along with the relevant fuel costs) enables a generator to optimise the real-time despatch of plant, perform hedging decisions and formulate suitable outage plans. This is necessary to meet demand at the lowest cost (benefiting consumers) and inefficient signals will limit the achievement of this aim. In the long term, robust price formation is an essential feature of a suitable investment environment and, therefore, maintaining security of supply.

It is important that generation is exposed to and can respond to short term price signals, for example to generate more when supply is low and prices high and vice versa. This is less material for some technologies where the ability to despatch generation to meet price signals is reduced (for example, wind). Any incentive to bid negatively to capture support could be mitigated by paying support on available capacity rather than outturn production.

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?

Some members consider that the analysis accompanying the consultation may have overstated the likely reduction in the cost of capital associated with CfDs, although there is likely to be some benefit here. However, the key considerations in selecting a mechanism should be the level of reduction in risk that it represents and whether the mechanism will work for investors. Different investors have differing appetites for and attitudes to risk and the Government needs to consider what type of investors it is hoping to attract.

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 the existing investor base?

A lower cost of capital should go some way towards attracting investment. However, the wholesale price risk is just one of a number faced by investors. Construction and operational risk are also significant and these will remain whichever support mechanism is introduced. Construction risk in particular is a key constraint on the availability of finance and there is limited capacity for utilities/developers to take this hit to the balance sheet. Investors will need to make returns commensurate with the risks still faced.

Investors are people who evaluate the risks with future prospects and place scarce capital where they judge it can achieve the greatest benefit. This produces the greatest return on capital and in turn rewards and multiplies the capital investment. The possibility of failure and the evolutionary nature of market discovery are critical to true investment.

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

It is essential that the model of FIT adopted is attractive to investors and is effective in supporting all low carbon generators. This will largely depend on the many detailed design issues that have yet to be clarified. We have commented below on some issues that the Government will need to consider when developing the practicalities of its proposals. The Association would be pleased to work closely with DECC to help evolve the details of whichever support mechanism the Government decides is most suitable.

The mechanism must provide all electricity producers with an appropriate level of certainty and avoid complexity. The Association does not support the use of auctions to allocate a FIT as this gives no certainty to a developer that he will be able to obtain a contract. The contracts will need to be underwritten by Government to give investors sufficient certainty that they will be honoured. If it is too complex to participate in the CfD process or too difficult to predict levels of CfD payments and to manage that cash flow, some developers, in particular smaller ones, could be pushed out of the market.

The Association is not convinced that all detailed elements of the FIT mechanism could be uniformly applied across the wide range of low carbon technologies that the Government intends to be covered by a FIT and adjustments may therefore need to be made to reflect the differing nature of some technologies. For example, the discounts applied to variable renewable output in PPAs to cover the balancing and cannibalisation risk would mean that some projects would not be able to obtain the overall level of revenue envisaged under the CfD. It may therefore be appropriate to use a separate reference price, which would better reflect the income received by these projects or apply an adjustment factor to the reference price when calculating difference payments. However, the Association recognises the desirability of simple and transparent arrangements and it may therefore be preferable to use a uniform reference price and simply set a higher tariff for these technologies. The Government will also need to consider the appropriate averaging period for the reference price – a shorter term average reference price is likely to be more helpful for technologies with variable output.

The FIT payments will only represent only a part of a generator's overall revenue and the Government must be mindful of the impacts that the EMR proposals could have on opportunities for generators to sell their power and on wholesale electricity prices. Greater liquidity in the electricity market will be essential in order to facilitate the sale of renewable power and provide a transparent market price against which PPAs can be valued. This, coupled with a greater role for new market participants, such as aggregators, may help ensure a reasonable route to market for renewable generators' product. However, the Government will need to keep this issue under review, assessing the impact on other technologies and, if necessary, consider other mechanisms that would create a market pull for renewable power.

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 Association considers that increased long-term liquidity will be vital to the new arrangements, both in order to establish a reference price for the CfDs and to facilitate the sale of power by all generators.

A robust, reliable and transparent reference price will need to be determined.

Whatever the overall outcome, designing the mechanisms will be a challenging task, which will require more detailed analysis and consideration. We consider there to be value in additional industry engagement with Government to assess further options prior to the publication of the White Paper.

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

The Association appreciates the need to design a system that guards against negative prices and recognises that paying support on available capacity would mitigate against any incentive to bid negatively. In most cases available capacity would equate to outturn production, except in very few cases where constrained off. It should be relatively straightforward to identify these cases. We acknowledge, however, that a FIT paid on availability would be complex to implement. A combination of energy and availability may be appropriate.

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?

The EU Emissions Trading Scheme (EU ETS) sets the overall level of emissions that will be achieved in the traded sector out to 2020. The introduction of an EPS therefore will not result in any further reductions in CO_2 emissions from the traded sector. If investment in the UK resulted in greater reductions of CO_2 than would have occurred if an EPS had not been introduced, these would clearly have to be paid for by increased energy costs for UK consumers. In addition, the overall emissions reductions required across the EU would be easier to achieve as a consequence of higher UK investment and the overall cost of carbon across the EU would reduce. Competitors elsewhere in Europe would therefore benefit from lower costs of carbon and, consequently, energy. In effect, UK customers would be subsidising customers elsewhere in Europe.

The stated aim of the EPS as set out in the Coalition Programme for Government is to prevent coal-fired power stations being built unless they are equipped with sufficient Carbon Capture and Storage (CCS) to meet the EPS. However, the strategy for coal-fired power stations set by the previous Government already requires any new coal-fired power station to demonstrate CCS on at least 300 MW net capacity with the expectation that CCS would be retrofitted to its full capacity by 2025. Given this strategy, introduction of an EPS is considered to be unnecessary and premature. The legality of an EPS for CO_2 is also questionable in the context of Article 9 of the Industrial Emissions Directive (2010/75/EU), which appears to forbid the inclusion of an emission limit value for direct emissions of greenhouse gas in the permit issued to installations included in the scope of the Emissions Trading Directive (2003/87/EC).

We are concerned that an EPS, while acting as a moratorium on the construction of coal-fired power stations, will do nothing to incentivise demonstration and development of CCS technology. Development of CCS demonstration must be part of a wider strategy for delivering a low-carbon energy system which requires a comprehensive strategy to ensure that the necessary investment is forthcoming.

The EU ETS remains the key mechanism which will deliver emissions reductions in the electricity sector in the UK. Additional policies may be necessary to incentivise investment in specific low-carbon forms of electricity generation. However, an EPS, while it would prevent investment in unabated coal, would not provide any incentive for investment in other, low-carbon, electricity generation capacity.

While doing nothing to encourage investment in new low-carbon generation, an EPS could have potentially negative impacts on investors' confidence in funding new infrastructure in the UK. As a mechanism it would penalise investment in technologies with high levels of CO_2 while failing to create appropriate incentives or an effective framework to deliver the necessary investment in low-carbon technologies. The regulatory uncertainty engendered by the potential for the introduction of future EPSs for either coal- or gas-fired power stations will affect investors' decisions on whether to invest in the UK or not. This could have significant implications for security of electricity supply in the UK and consequently electricity prices for consumers. Rather than focussing on an EPS, Government should consider what is needed to make it attractive for investors to invest in low-carbon technology.

Suggestions that the level of an EPS could change over time or that an EPS could be introduced for gas-fired power stations will also have significant impacts on investor confidence. It needs to be recognised that, while CCS technology is a potential technique for the future low-carbon generation of electricity, the full technology chain has not yet been demonstrated and is not likely to be commercially available for a number of years.

Setting an EPS for a coal-fired power station with a demonstration plant fitted to 300MW is also likely to be difficult where the operating pattern and performance of the unit fitted with CCS is difficult to predict at this stage. The fact that CCS is at the demonstration stage means that it would be very difficult to set a meaningful EPS until it is clear that the unit fitted with CCS is fully operational and meeting expected CO_2 removal efficiencies. It is therefore difficult to see what can be achieved by setting an EPS prior to CCS being judged commercially available.

An EPS may have a role to play in setting future standards for fossil-fired power generation but it should only be introduced once the potential and costs of CCS on both coal- and gas-fired plant have been adequately assessed. A review of the technical and commercial viability of CCS technology in the UK by the Environment Agency is currently planned for 2018.

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 do not support the introduction of an EPS. An EPS will not drive forward the development of CCS technology. If investors perceive that it is too risky to invest in new coal-fired plant with demonstration on one unit because it is not clear that a future EPS level would be achievable, it could in fact work to delay driving the technology forward. The need to consider derogations from the EPS demonstrates that it is inappropriate to introduce such an intervention while CCS remains unproven for commercial scale electricity generation. If the UK's CCS demonstration projects are to become a reality, they should not be fettered by an EPS that will not be applied anywhere else in the EU.

However, if the Government remains determined to proceed with the introduction of one of the two options set out in the consultation paper, Option 1 (an annual limit equivalent to $600gCO_2/kWh$ for plant operating at baseload) would be the preferred option, but this will not work for CHP plant unless the heat element of emissions is excluded.

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 do not support the introduction of an EPS. However, if the Government remains determined to proceed with the introduction of such a mechanism, we agree that its scope should be limited to new coal-fired power stations and that the emission limit should be grandfathered at the point of consent. The Government should not attempt to determine the economic life of a power station; that is a matter for the operator and grandfathered emission limits should endure for the life of the installation.

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 do not agree that the EPS should be extended to cover existing plant in the event that they undergo significant life extensions or upgrades. Such an approach would introduce an unacceptable level of regulatory uncertainty and stifle investment in plant that will be needed to maintain security of supply during the transition to a low-carbon generating portfolio.

If a generator replaces the main components with new ones and in effect creates a new power station with the operating performance and life of a new plant, it would be only fair to subject it to an EPS as a new plant.

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

We agree that it would be reasonable to incorporate a review of the EPS, if it is introduced, into the progress reports required under the Energy Act 2010. The level of the EPS should take account of the available CCS technology, based on both technical and economic assessments. We consider that an EPS should not be introduced while CCS remains unproven for commercial scale electricity generation and that the use of such a mechanism in the future could be assessed in the context of the progress reports required under the Energy Act 2010.

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

If an EPS is introduced, we see no need to invoke special considerations for the combustion of biomass. Biomass ratings for the purposes of EPS should be consistent with EU ETS Monitoring, Reporting and Verification standards.

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

The need to consider exceptions to the EPS at this stage suggests that the Government is uncertain about the effects of the mechanism on security of supply. That uncertainty may arise from the introduction of an emission limit before the capabilities of CCS technology have been proven at commercial scale. If an EPS is introduced, the scope of any exceptions should be set out clearly in advance, together with the procedure for implementing them, as they have the potential to affect operating decisions and competition in the wholesale market.

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?

Our members have different views on the need for a separate mechanism to reward capacity. Some can see merit in such an approach, some fundamentally disagree with the need for a capacity mechanism, while others will reserve judgement until further detail is available about the design of such a mechanism and greater clarity about which plant would be affected among existing plant and/or plant yet to be commissioned.

While members seek to understand how to avoid potential distortions to wholesale prices, they note that because Government perceives an increasing risk to security of supply arising from the transition to low-carbon generation, it is consulting on introducing a capacity mechanism to explicitly reward the provision of capacity. The implication could be that the problem is seen as the potentially large amount of wind power which will be on the system when the EU renewables target is met (requiring more 'back-up' than other plant), but it is not entirely clear which problem the Government is attempting to address (e.g. peak demand, flexibility, or both) and whether a capacity mechanism remains the best approach. We therefore seek clarity on the rationale behind the proposal.

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

Some of our members support this approach, attributing the current capacity margin as an accident of history which will not continue into the future.

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

Members have different views on whether this would be a suitable approach for the UK. Indeed some firmly believe that the case in favour of introducing a capacity mechanism has not been made and should therefore not be a priority for EMR. They would support investigation around refinement of and enhancements to the existing reserve market Short Term Operating Reserve (STOR). Others would like to understand more about what is meant by a targeted capacity mechanism. Some of those who support the proposal consider that it may be appropriate to have a mechanism which is available only to generation which meets certain criteria (availability, flexibility, etc) but this support should be open to all within this grouping. Others who support the proposal consider that it is crucial that the mechanism is available to all generation.

Under the targeted mechanism proposed by DECC, maybe 5GW of generation would receive a targeted capacity payment; this cost feeds into cashout prices and hence wholesale prices to make good the 'missing money' for capacity not in receipt of the payment. As proposed, the targeted mechanism is little different to a long term STOR contract. Like STOR contracts, it will cap energy prices at the peak, reducing revenues unless the cost of the targeted mechanism is reflected in the wholesale price at the time the capacity generates. This will have the effect of reducing the incentive for marginal plant outside of this mechanism to stay connected. This reduction in peak revenues will feed through to that earned by all plant, resulting in reduced earnings.

Cashout prices could be modified to deal with the issue of this 'missing money'. This could be achieved through Ofgem undertaking a Significant Code Review or through primary legislation. However, this mechanism would not be bankable for existing plant considering investment. If DECC agrees that a targeted mechanism should not be introduced, then it is difficult to see how a mechanism rewarding all capacity could be delivered through a cashout SCR. They are nothing to do with each other – the level of imbalance and the revenue received/paid for imbalances do not relate to plant availability/flexibility. The cashout mechanism design would have to ensure that prices did spike sufficiently to capture this missing money and at appropriate times. This in itself is not a simple task; industry has already devoted considerable time to ways of better reflecting the cost of reserve holding in cashout prices and so far has not come up with a solution that the regulator has been willing to adopt. This is without also having to consider the unpredictability of wind in the mechanism design.

As with STOR, the system operator will ignore the sunken capacity costs when deciding to utilise this 'targeted' plant; it won't just be used over peak periods, it will be used when its utilisation cost is in merit. This will crowd out other plant priced above the utilisation cost of the 'targeted' plant in the merit order even though its overall generation costs are lower, expensive plant will run ahead of cheaper plant, distorting the price signal. Concerns could be addressed by appropriate rules. Capturing the cost of plant in the targeted capacity mechanism will result in meaningless and even more unpredictable price spikes.

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.*

Those members who do not support the introduction of a capacity mechanism consider that if concerns remain about the capacity margin, Government should seek to refine and build on the existing reserve market mechanisms such as STOR, possibly with adjusted cashout prices. If designed carefully, incremental STOR procurement to provide a pre-defined level of additional capacity could have a minimal impact on the market.

Some members support a general capacity mechanism, considering that, by preventing the early closure of existing plant, a general capacity mechanism will be cheaper in the long-run than either a targeted or no capacity mechanism through a combination of reduced lost load and reduced new investment cost. If introduced, a general capacity mechanism should profile payment to times when capacity was the highest value.

Members willing to consider a targeted capacity mechanism consider that, if designed correctly, it is the approach which would allow prices to continue to reflect the balance of supply and demand in the market. Its introduction would, however, be conditional on the full cost of any capacity contracted under the targeted mechanism being reflected into the wholesale market when that plant is run. This is important in order to encourage and incentivise demand side response through exposure to volatile peak prices. The targeted mechanism should have the objective of providing additional incentives for generators to make capacity available at the minimum additional cost to consumers and the system's operator should be incentivised to deliver that. In order to maintain investor confidence, the methodology the system's operator uses for contracting for new capacity needs to be transparent and entirely predictable, with any changes required over time consulted on well in advance.

Some of our members state that a targeted capacity mechanism is not their preferred option, arguing that if conventional generation is denied peak rents because of the introduction of a targeted mechanism and these are not replaced by other revenues, then costs are likely not to be recovered (the capacity scheme would quickly widen). If a targeted mechanism is not introduced, however, then a wider system which is volume-based driven may be required with the volume driven by the dilution of an annual pot similar to the Irish scheme and determined by system margin. The Irish scheme's pot is divided into month allocations depending on forecast demand in those periods. This should incentivise efficient dispatch and scheduling of maintenance and outages.

Others consider that, as proposed, the targeted mechanism is little different to a long term STOR contract which would effectively cap energy prices at the peak reducing potential revenues and the viability of plant not under contract. The concern is that it will lead to plant closure exacerbating security of supply issues or, alternatively, the need for more targeted payments. Ultimately this could lead to a situation where all capacity might eventually be covered by a "targeted" payment, but on an opaque case-by-case basis rather than market-determined basis. This scenario threatens the ongoing viability of the energy market which effectively collapses, resulting in a "central buyer" model by the back door.

It is paramount that the impact of a move towards any form of capacity mechanism must be fully understood to avoid unintended consequences for both existing and future generators. There needs to be further consultation with market participants and with network operators on the design and operation of the Government's preferred capacity mechanism, given that the Government's policy work in this area is not yet fully developed.

Although the need for any capacity mechanism is not universally agreed within our membership, we consider that, if introduced, any mechanism should be volume rather than price based. The entity contracting for capacity under the targeted mechanism needs to be independent of other commercial activities and of political influence. If this role is undertaken by NGC as the System Operator, it should be entirely ring fenced from its other operations.

Members do not believe that the Swedish model for a targeted mechanism is applicable to the UK. Sweden's generation capacity is almost entirely hydro or nuclear, with virtually no fossil plant. Taking into account the hydro capacity in neighbouring Norway, the Nordic system benefits from considerable flexibility and capacity is largely a water management issue. Moreover, the Swedish mechanism only applies in extreme circumstances when the market coupling result would lead to curtailment. We consider this scheme to be more of a water management type payment, as opposed to a large backup type mechanism needed in the UK.

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?

It very much depends upon how a capacity mechanism is to be applied and is therefore difficult to assess at this time. However, it is important that the design of any mechanism allows the demand side to participate.

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

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

See our answer to Question 22 above. Some members consider that either approach could be made to work if the full cost paid out as a capacity payment is reflected into the wholesale market which could be via the cashout price or another mechanism. Economic dispatch may offer a more market-based approach and will probably contribute to lower overall costs. A last-resort approach might also be difficult to sustain if the System Operator is holding a large volume of capacity in reserve as there will be pressure to allow this plant to run more frequently if other capacity has higher costs.

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

No, this is not necessary. The GB system is not sufficiently large or constrained to warrant the additional complexities that would arise. If demand is higher in a constrained geographical area then the plant will be called to run more often as happens now. In the long run, the higher potential load factors will be factored into investment decisions

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?

The Government has to establish whether this package of proposals will work without there being a serious imbalance between the long-standing political objectives for the industry. The Association is also interested in this question, not least because failure could lead to further changes in public policy and new political and regulatory risk. We look forward to discussing the proposals with Government. In the meantime, it is probably fair to say that, whereas a transition to a low carbon electricity industry should be compatible with security of supply, it is less clear whether, with reduced reliance on a competitive market, this can be achieved at an acceptable price – the judges of which are ultimately the customers, domestic and commercial.

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

AEP members have differing views on the various mechanisms considered in this consultation and are subsequently able to provide only high level analysis of the packages. In reference to some of the features of each we comment as follows:

<u>Package 1</u> (namely carbon price support, EPS and capacity mechanism) may not be sufficient to meet the Government's decarbonisation, affordability or security objectives. While the combination of this package appears coherent, it is unlikely to provide the certainty required for investment in nuclear or CCS. A carbon price intervention alone (including one that is designed to offer some predictability in CO_2 costs) is unlikely to provide stimulus for investors to release the billions of pounds required for new low carbon base-load thermal generation. The Association does not see the need for the introduction of an EPS. Furthermore, it is not clear from the description of the package whether other reforms are likely to occur in the support mechanisms for renewable electricity.

<u>Package 2</u> (namely premium FIT, carbon price support, EPS and capacity mechanism) may be a credible alternative to the Government's preferred package of options. It has the advantage of providing minimum premium support to investors and provides investors with a more attractive balance or risk and return based on the expectation of future, guaranteed revenues. It also provides a clearer pathway than Package 1 for renewable electricity up to the Government's ambition of 35% of the electricity mix from renewable sources and it may be more likely to encourage investment in new nuclear and CCS.

The carbon price will have greater relevance in this package as it is combined with the premium payments, especially for renewables. We agree that the package relies on operators to manage the electricity wholesale price risk entirely. Package 2 must also have an appropriately designed capacity payment scheme to be effective, about which members opinions vary.

<u>Package 3</u> (namely the Government's preferred approach) – see our comments throughout this consultation.

<u>Package 4</u> (namely fixed payment FIT, carbon price support, EPS and capacity mechanism) would not be seen as favourable. We agree with the Government's conclusions on the fixed FIT scheme.

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?

This should become evident through the cost-benefit analysis that must be undertaken to assess the viability and suitability of the proposals against the objectives set by Government.

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

The implications for the Renewables Obligation of the transition to a new support mechanism for renewables, including the proposal in the EMR consultation to fix the price of a Renewables Obligation Certificate, will need to be carefully considered. The tensions between the carbon floor price and the EU ETS are also an issue. Finally, it is paramount that the industry has certainty on grandfathering options and the length of time that 'interventions' are to be applied.

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?

Our members agree that a speedy but fully considered decision is required as investment decisions being made now are awaiting the outcome of the Government's deliberations. Any announcements need to include clear messages about the protection of the Renewables Obligation and transfer mechanisms to any longer-term schemes.

Risks we have identified to date include:

- Actually working up the details of the proposals. How is it proposed that this exercise be progressed?
- Resourcing and completing negotiations on the forms of contract to be used. We need to fully understand:
  - the details associated with contract operation such as payment timings;
  - the credit requirements and security over assets;
  - how the arrangements would be compatible with future financing alternatives;
  - that there are arrangements to deal with construction timing uncertainties; and
  - that we can mitigate against future change of law risks.
- We need to better understand the timelines for legislation.

- How and when we begin the process for setting up the new organisations to administer the CfD or premium FITs.
- We need to understand the role of the existing regulatory bodies such as Ofgem.
- We need to have clarity on the EU position regarding approvals and State Aid status.
- We need further detail on the proposed payment and cashflow mechanisms for funding the low carbon revenue support mechanism. For example, how and when are the costs of the low carbon support arrangements passed on to suppliers and customers.
- We need to fully understand the working capital issues associated with the potential mismatch of cashflows.
- We must ensure that there are provisions in place should we see the bankruptcy of suppliers or generators.

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?*

The Association recognises the need to ensure that the most cost-effective support is implemented and therefore appreciates the desirability of some form of price discovery when setting levels of support. However, we consider that an administered price should be used and that there should be open access to support for all developers. This would be far preferable to the use of auctions. Auctions present a major barrier to investment because they provide no guarantee that a project will be secure a CfD and then be built once external factors have been considered. Members do not agree that auctions should be implemented now. Implementing auctions / tenders in such short implementation timescales adds an unnecessary additional complication during the transition period to 2017.

The issues that would need to be addressed for an auctioning process to work effectively are listed below and it does not appear that these could be successfully overcome at this stage:

- It would be difficult to accommodate project planning and consultation as there can be no assurance that a project would necessarily obtain support under an auctioning process.
- Different auctioning rounds are likely to lead to a stop-start approach to development, which could lead to bottlenecks in supply chains and planning systems.
- Projects would face significant upfront costs to participate in an auction, which could discourage some companies from participating.
- The difficulty of ensuring that all necessary consents, especially planning permission and grid connection, could be obtained alongside financial support under the new mechanism.
- Nuclear and offshore wind will be large projects with single developers on pre-determined sites and are therefore unlikely to be suitable for auctioning, whereas onshore renewable energy projects are likely to be smaller, leading to greater competition and potentially more speculative bidding.
- Based on the experience of the RO, it will be necessary to band the support mechanism, setting different levels of support for different technologies, in order to incentivise the deployment of a wide range of technologies. Separate auctions are therefore likely to be required for each technology. This would, in effect, allow the Government to influence the fuel mix.
- Winning an auction would not necessarily lead to the building of plant. Some winning bidders may find it uneconomic to build, while others may see winning as the start of a protracted negotiation period to address issues not covered in the bid, delaying construction. It would be difficult for the Government to impose penalties for non-development of a winning project given the range of factors that are outside of a project developer's control.

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

Whether a premium FIT or FIT with CfD is adopted, a new, credit worthy, Government backed agency will need to be established to deliver feed-in tariff payments. The establishment of an agency should begin now, prior to it formally being constituted by legislation, so that the process of setting up these institutions does not delay the implementation of the new support regime once legislation is introduced.

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?

See answers to previous questions.

Renewables – Maintaining investor confidence

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

The RO is a mechanism that is well understood by investors. A change to the support mechanism for renewables would introduce the risk of a hiatus in deployment unless the transition is adequately planned and investors are given full transparency in tariff levels and implementation methodologies.

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

The objectives of the transition must be to protect existing RO investments, prevent a hiatus in investment and encourage further renewables deployment.

It is critical that investors in renewable energy projects receive clarity about the future operation of the RO on the same timescale as the current RO banding review, i.e. by Autumn 2011. Many projects, representing several billion pounds of investment, have been put on hold while awaiting the outcome of that banding review. If these projects do not have sufficient visibility of and confidence in the RO arrangements after 2017 to form a reasonable view of future revenue and cash flows by the time the banding review is concluded, there could be a further hiatus in investment, with very serious repercussions for both existing development projects and the Government's legally binding renewable energy targets.

We would welcome clarity on the following issues in the forthcoming White Paper:

- What is the closing date for accreditation of projects within the RO and what qualification criteria will be adopted?
- Will the RO remain as a supplier obligation or will a Government agency take over responsibility for buying the certificates?
- If the RO remains as a supplier obligation:
    - What will be the future method of calculating the size of the obligation?
- If a Government agency takes over the purchasing of the certificates:
    - What will the price be or how will it be determined?
    - What will the interval of purchase be?
    - Which body will be responsible for purchasing the certificates?

- What grandfathering arrangements, if any, will be put in place for bioliquids, co-firing and energy crops?
    - If no grandfathering is to be put in place for these technologies, what will be the process and timing for determining future banding levels?

For existing projects accredited for the RO, DECC must clarify any future rules concerning refurbishment or replacement of plant – whether this support will be provided under the RO or the new mechanism – and, similarly, how additional capacity will be treated.

There is no clarity in the consultation document around the Government's intention to maintain the current feed-in tariff for small-scale renewable energy projects. The future of this scheme and whether projects below 5 MW will have the option to access the CfD mechanism in future must also be confirmed.

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

We consider that developers should be offered a choice of whether to accredit under the RO or to receive support under the new scheme before 1 April 2017. This would allow those developers that are currently planning projects under the RO to go ahead with them, while companies that consider the new support mechanism to be attractive could opt for that instead. A choice would allow the industry to become familiar and comfortable with the new mechanism before it became mandatory for all projects. Provided that the choice is made early enough in the development process this should not have a negative impact on the predictability of the RO.

The Government must consider the risk that some projects could be developed with the aim of receiving support under the RO, but might encounter delays, especially during construction, which mean that they are unable to generate electricity and therefore accredit for the RO before the 1 April 2017 cut-off date. Depending on the qualification criteria adopted, these projects may also have missed their opportunity to claim support under the new mechanism. We therefore consider that greater flexibility may need to be introduced to the qualification criteria for the RO to allow projects that had already notified DECC of their intention to enter the RO before 1 April 2017 to access it (subject to pre-registration, qualification criteria and progress monitoring) if they are subject to unavoidable delays, rather than relying solely on the current accreditation milestone of commissioning.

If the Government was to offer no flexibility around the 31 March 2017 cut-off date for accrediting for the RO, it would be essential for the new support mechanism to be implemented on the timescale envisaged in the consultation document in order to give investors early enough clarity of the new arrangements. Otherwise, if timescales were to slip, some projects with long construction periods may be ready to reach financial close in the knowledge that they would be unable to accredit for the RO by 31 March 2017 but without enough visibility and certainty of the detail of the new support scheme arrangements.

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?*

In principle, the Association firmly supports the concept of grandfathering of support, without which investors will not have the confidence to make long term investments. It may be appropriate to give non-grandfathered technologies the option to transfer to the new support mechanism. If the Government chooses not to grandfather some technologies within the RO, it would need to consider the most appropriate intervals for future banding reviews in order to promote greater investor confidence.

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

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

We do not consider that the first option (using both the fixed targets and headroom) post 2017 is viable as it could lead to the level of the Obligation being substantially higher than actual qualifying output once capacity starts to retire from the RO. If DECC is continue to set the level of the Obligation each year after 2017, it would therefore have to use only Calculation B.

Members have differing views on the desirability of fixing the price of a ROC. While this could provide more certainty over future ROC values than relying on DECC to set the level of the Obligation accurately, fixing the price of a ROC would represent a fundamental change in the nature of the RO. The Association also notes that this proposal could be difficult to implement where ROCs are sold through existing PPAs. If the price of a ROC is to be fixed, the key consideration will be how to determine a reasonable ROC value. The process for doing this must be transparent and decisions taken on the same timeline as the banding review.

APPENDIX 2 - Carbon Price Support

Response to HM Treasury's Consultation on "Carbon price floor: support and certainty for low-carbon investment", Published December 2010

About AEP

The Association of Electricity Producers (AEP) represents large, medium and small companies accounting for more than 95 per cent of the UK generating capacity, together with a number of businesses that provide equipment and services to the generating industry. Between them, the members embrace all of the generating technologies used commercially in the UK, from coal, gas and nuclear power, to a wide range of renewable energies. Members operate in a competitive electricity market and they have a keen interest in its success – not only in delivering power at the best possible price, but also in meeting environmental requirements. Contact details for the Association are given at the end of this paper.

Introduction

AEP members accept the principle that, to achieve longer-term carbon reduction ambitions, short and medium term investment decisions have to be on the low-carbon path. However, the sums of money required to replace ageing plant and, more significantly, to meet the requirements of the Renewable Energy Directive and the UK's own target for the reduction of carbon emissions mean that the energy industry has to attract significant new investment – £200 billion for new power production and networks and gas infrastructure by 2020 and another huge sum in the following decade. In the present financial climate, there is a serious risk that this investment will not be available if investors do not have confidence in the UK electricity market arrangements. If these huge sums are to be attracted to the UK, there must be a clear, credible and stable political and regulatory environment which delivers appropriate rates of return. We do not have that today, because a) the current design of the electricity market will not bring forward the full range of low carbon technologies needed to meet the UK's highly demanding low carbon agenda in an economically efficient manner and b) the emission limits applied by the EU Emissions Trading Scheme (EUETS) currently do not offer the visibility and confidence of longevity beyond 2020 that would help to bring forward the diverse low carbon investment required to meet those UK targets. There is a fundamental need to align the policy framework with the investment timescales and payback periods for large-scale, low-carbon technologies.

Given the importance of the Government's proposed changes to the Electricity Market, of which carbon price support is a key element, we would have appreciated more time to consider our response alongside the Electricity Market Reform consultation issued by DECC in December 2010. That could have been achieved if the Government had followed its own Code of Practice on consultation.

Our responses to specific questions in the consultation document are set out below.

Investment

3.A1: What are your expectations about the carbon price in 2020 and 2030? And how important a factor will it be when considering investment in low-carbon generation?

The AEP supports the EUETS as an EU-wide mechanism to deliver a price signal for carbon. We acknowledge that the de-carbonisation of the power sector has a critical role to play in achieving the CO_2 emission reduction target set by the EU and the more ambitious targets set out in UK legislation. A stronger carbon price signal will help to encourage delivery of de-carbonisation in electricity generation. Given the emissions reduction trajectory established for Phase 3 of the EUETS, some parties may have sufficient confidence to take a view on how the carbon price will rise in the period to 2020. Individual companies will have their own view of prices informed by third party data, but company views cannot be aired or shared for competition reasons. Any view would, however, have to be amended if the EU changed its ambition for CO_2 emission reduction from 20% to 30% by 2020. It is therefore very difficult to take a firm view on the carbon price that may emerge up until 2020 and the same applies beyond 2020 because the trajectory of the EU emissions cap for that period, although prescribed in legislation, is subject to political uncertainty.

The importance of the price of carbon to investment in low-carbon generation will be technology-specific and ultimately dependent on the outcome of the Electricity Market Reform package of measures.

3.A2: If investors have greater certainty in the future long-term price of carbon, would this increase investment in low-carbon electricity generation in the UK? If so, please explain why.

A stronger carbon price signal will help to encourage delivery of de-carbonisation in electricity generation. We agree with the Government that this will not be sufficient on its own and that, for many low-carbon developments, it is likely that other incentives will also be needed to attract the necessary investment, including a system of revenue support. We look to the Government's Electricity Market Reform (EMR) to deliver a suitable framework of policy and regulation.

3.A3: How much certainty would investors attribute to a carbon price support mechanism if it were delivered through the tax system?

While any mechanism delivered through the tax system is subject to political risk and, unlike a contractually-based mechanism, risks revision in response to changing political imperatives, it may nonetheless be helpful in influencing investment decisions. However, some issues may arise if the core purpose of the policy measure becomes obscured and the tax simply provides a means for Government to raise revenues. Successive Governments may take different views of the purpose of the tax or the rate it should be set at, taking account of other goals including ensuring that energy prices remain affordable for consumers. This makes it difficult to rely on the tax alone as a means of incentivising investments in assets which will not begin operation until towards the end of this decade. The greater the perceived risk, the greater the discount that will be applied to it for investment and financing purposes. To offset that risk, we would like to see a clear statement of the Government's objectives for the use of the mechanism. That could be achieved by specifying in primary legislation how the tax will be set and might be adjusted in the future. Such provisions will need to take into account the potential impacts of revisions to the EUETS on which the UK's carbon tax is predicated.

3.A4: In addition to carbon price support, is further reform of the electricity market necessary to decarbonise the power sector in the UK?

The current design of the electricity market will not bring forward the full range of low-carbon technologies needed to meet the UK's highly demanding low-carbon agenda in an economically efficient manner. We are considering the Government's proposals on Feed-in Tariffs, capacity mechanisms and an Environmental Performance Standard (EPS). AEP is not convinced of the benefits of introducing an EPS.

The AEP wishes to see a robust, competitive and liquid wholesale electricity market, which should provide a reliable and credible wholesale price where the investments required to meet the Government's de-carbonisation objectives are incentivised at best value to consumers, whilst maintaining security of supply.

Administration

4.B1: What changes would you need to make to your procedures and accounting systems to ensure you correctly account for CCL on supplies to electricity generators?

This is a question for individual operators to address.

4.B2: How long would you need to make the necessary changes to your systems to account for CCL on supplies to electricity generators?

This is a question for individual operators to address.

4.B3: Please provide an estimate of how much the system changes would cost, both one-off and continuing?

This is a question for individual operators to address.

Types of generator

4.C1: Do you agree that all types of electricity generators should be treated equally under the proposed changes? If not, please explain why.

Yes, with the exceptions addressed under Questions 4.C2 and 4.D3.

4.C2: Is there a case for providing additional or more preferential treatment for CHP? If so, what is the best way of achieving this?

We do not see a case for providing additional or more preferential treatment for CHP, but nor should it be disincentivised. Under the proposed arrangements, we consider that this is likely to happen. Given that the objective of the tax is to support the EUETS, the proposed application of the CCL to fossil fuels should reflect the benefits of CHP in the same way as the EUETS (which provides for free allocation of allowances to electricity generators for heat production). This would mean ensuring that CHP did not pay the levy on fossil fuel supplied for heat production.

The consultation document states in 4.25 that CHP obtains various forms of exemption. The list is inaccurate and misleading e.g. the EUA ring-fence does not apply from 2013, CRC does not include heat and the remaining incentives are available to a few, but by no means all, Good Quality CHP plants.

The rationale given in 4.27 for including heat in the Carbon Price mechanism is simplicity, fairness and polluter pays. Excluding heat would appear to be simple, by using information currently obtained in the CHPQA submissions. The 'fairness' criterion does not appear to be met as the proposals penalise CHP and create the perverse outcome that CHP operators may pay Government for making carbon savings. The question structure implies that the proposals already provide preferential treatment for CHP and other stakeholders are likely to respond "no" to this question as a result.

Charging CHPs Carbon Price Support on the fuel used to generate heat means that CHP projects will be disadvantaged versus the separate production of power and heat. The vast majority of hosts have CCAs (hence are 65% exempt from CCL) or are in exempt sectors such as refining and would therefore not be subject to CCL for the production of heat in stand-alone boilers. The incentive as currently drafted would mean that one such site that saves carbon by CHP investment (as CHP emits less carbon than the separate production of power and heat), would be paying more Carbon Price Support than a site that imports power and has stand-alone boilers. There is no relief from this incremental cost since it cannot be passed through to a heat customer. This has the impact of disincentivising CHP investment and may ultimately even encourage some existing CHP facilities to operate as a CCGT and use standalone boilers. This will obviously act as a disincentive to investment in new CHP, and it may also affect how existing facilities are run in the future. Some CHP would be incentivised to declassify as CHP (thus increasing carbon emissions) or operate differently. For industry that requires very stable high pressure steam, CHP is the most efficient method of doing so available to them.

The Cogen Directive ensures there are no State Aid issues.

4.C3: Do you agree that tax relief should be considered for power stations with CCS? If so, what are the practical issues in designing a relief; what operational standards should a CCS plant meet in order to be eligible; and how might these issues differ for demonstration projects?

Yes. The relief should be aligned with the volume of carbon abated/sequestered as determined through the Monitoring Reporting and Verification requirements of the EUETS.

Imports and exports

4.D1: What impact would the Government's proposals have on electricity generators and suppliers that export or import electricity?

The Government's proposals are likely to increase the incentive for greater levels of import of electricity to the UK. With the future prospect of 4 GW of interconnector capacity, the Government may not have attached sufficient significance to this in its impact assessment. Moreover, arbitrage opportunities could be expected to stimulate further investment to the detriment of indigenous producers. We would prefer to have an EU-wide mechanism to support the carbon price, which would create a level playing field for electricity generation and supply.

4.D2: What impact might the proposals have on trading arrangements for electricity?

The severity of the impact of the proposals on electricity trading arrangements will depend largely on the way in which they are introduced. To avoid market shocks, the method and timing of setting the tax should be visible to operators well in advance of its introduction, be as predictable as possible and be aligned with market arrangements. A lack of predictability would tend to reduce hedging through forward sales of electricity and thereby reduce market liquidity.

Generators operating under long term power purchase agreements which do not include adequate provision for price review in the event of the introduction of a tax on input fuel could face financial difficulties. For instance, National Grid's standard terms for the procurement of long term STOR service provision do not include a right for the generator to vary its price in the event of introduction of a carbon tax (or reduction in the rate of reclaimable fuel duty), nor does National Grid accept STOR tenders where prices are linked to wholesale electricity prices, so even an indirect and delayed indirect price correction mechanism may not be available to long term STOR providers.

4.D3: What impact might the proposals have on electricity generation, trading and supply in the single electricity market in Northern Ireland and Ireland?

The Single Electricity Market (SEM) is the all-island electricity market for Northern Ireland and the Republic of Ireland. The SEM is a centrally dispatched gross mandatory pool and participation in the pool is mandatory for generators (greater or equal than 10MW) and suppliers. A market power mitigation strategy was developed as part of the implementation of the SEM and a key feature of this is that generators are required to bid their power into the pool at short run marginal cost (the incremental cost which a generator incurs to generate an incremental unit of power). Generation Licence conditions and a Bidding Code of Practice set out the basis on which generators are expected to bid in the SEM and a Market Monitoring Unit monitors compliance against these.

The AEP considers that the increase in the cost of fossil fuels used to generate electricity, caused by the Government's proposal to remove the CCL and fuel duty exemptions, clearly meets the SEM's definition of a short run marginal cost and as such would be recovered through a generator's bid. However, we are aware that the Regulatory Authorities in Northern Ireland and the Republic of Ireland (the Northern Ireland Authority for Utility Regulation and the Commission for Energy Regulation who manage the SEM through the SEM Committee) have recently directed generators in the Republic of Ireland not to include a carbon levy (the Electricity Regulation (Amendment)(Carbon Revenue Levy) Act 2010 which claws back the value of free EUAs granted) in their bids into the market and given this precedent, there is a risk they would similarly not permit the inclusion of the proposed CCL and fuel duty in generator bids. Failure to do so would result in Northern Ireland generators operating at a loss when they are the price setting plant/marginal plant in the SEM, or at lower margins when they are not the price setting/marginal plant. This would be both anti-competitive and unsustainable and in turn could lead to security of supply issues. We also consider that it would be inconsistent with the Bidding Code of Practice and Generator Licence conditions, but in light of the recent precedent established by the SEM Committee, there is a considerable risk. The AEP therefore requests that the Government confirm with the SEM Committee that the inclusion of CCL and fuel duty in generator bids in the SEM is consistent with the Bidding Code of Practice and Generator Licence conditions.

The SEM is a unique market in that it operates across two separate legal jurisdictions with generators in Northern Ireland and the Republic of Ireland directly competing with each other. The introduction of the proposed CCL and fuel duty on fossil fuels would increase the fuel costs for Northern Ireland generators relative to their Republic of Ireland counterparts (assuming that the CCL and fuel duty can be included in generator bids) thereby weakening their competitive position in the market and ultimately their profitability and sustainability.

Carbon price support mechanism

4.E1: How should the carbon price support rates be set in order to increase certainty for investors, in particular over the medium and long term?

The carbon price support rates should be set to provide:

- certainty for operators in the electricity market e.g. by giving visibility of the target price trajectory well ahead of time (at least a three-year horizon would be reasonable, in line with current strategies for forward sales);
- an indication of the direction of travel in the longer term;
- a link with the existing carbon market e.g. via reference to a traded index.

4.E2: Which mechanism, or alternative approach, would you most support and why?

AEP member companies would like to have more detail on the three options set out in the consultation before expressing a preference. However, we agree that whichever mechanism is selected, it should:

- provide a visible target price trajectory up to three years ahead;
- be fully transparent;
- be indexed against the current carbon market, based on the EUETS;
- address issues around the exchange rate to be used for conversion between Euros and Sterling
- not be applied retrospectively.

4.E3: What impact would the proposals have on your carbon trading arrangements?

This is a question for individual operators to address.

Future price of carbon

4.F1: Should the Government target a certain carbon price a) for 2020 and b) for 2030? If so, at what level?

If a carbon price floor mechanism is to be introduced, the Government should target a certain carbon price covering both the EUETS and the carbon support rate for 2020. Given the lack of visibility of the emissions reduction trajectory in the EUETS post-2020 and the political uncertainty surrounding EU emission reduction targets for 2020, it will be challenging to target a price for either 2020 or 2030 at this stage. AEP is not in a position to suggest a target price.

4.F2: What is the most appropriate carbon price for the UK to meet its emissions reduction targets in the power generation sector? How would this be affected by changes in the structure of the electricity market?

AEP is not in a position to suggest a target price.

4.F3: When would be the most appropriate time for introducing a carbon price support mechanism and what would be the most appropriate level?

We would like to see a minimum of two years between the announcement of a mechanism and rates in the Budget Statement and their coming into force. Beyond that, AEP members differ in their views on the timing of the implementation of the mechanism. Dates ranging from 2013 to 2015 have been suggested. However, the timing of implementation in any case needs to:

- coincide with investment horizons
- provide transparency in the electricity and carbon markets;
- take account of legacy long-term power off-take contracts.

The effect of the carbon price support should be relatively low in its early years, with an increasing trajectory over time to smooth the effects on the market, which would also limit the extent of any impact on security of supply, consumers and UK competitiveness.

Electricity investment

5.B1: What impact would you expect the carbon price support mechanism to have on investment in low-carbon electricity generation?

This will depend on the combined outcomes of both the carbon price support mechanism and the other measures proposed under Electricity Market Reform.

5.B2: What other impacts would you expect carbon price support to have on investment decisions in the electricity market?

Carbon price support is likely to affect investment decisions for projects that are not subject to any "contract for difference" model as proposed under EMR. It will also affect investment decisions for existing coal and gas-fired power stations that will be subject to the requirements of the Industrial Emissions Directive in the period post-2015. Those stations are expected to make an important contribution to the security of electricity supply during the transition to a low-carbon generating fleet.

5.B3: How should carbon price support be structured to support investment in electricity generation whilst limiting impacts on the wholesale electricity price?

As the purpose of the carbon price support mechanism is to influence the wholesale price of electricity, it should be introduced in a way that minimises disruption of the existing electricity market arrangements. Introducing the mechanism so that its impact is relatively low in its early years, with an increasing trajectory over time, will help to smooth the effects on the market.

Existing low-carbon generators

5.C1: Can you provide an assessment of the impact of the proposals on your generation portfolio and overall profitability?

This is a question for individual operators to address.

5.C2: What would be the implications of supporting the carbon price for existing electricity generators and how should the Government take this into account?

This is a question for individual operators to address.

Electricity price impacts

5.D1: How do you currently manage fluctuations in the wholesale electricity price?

This is a question for individual operators to address.

5.D2: What difference will supporting the carbon price make to your business?

This is a question for individual operators to address.

5.D3: As an electricity generator or supplier, how much of the cost of the carbon price support would you pass on to consumers?

This is a question for individual operators to address.

5.D4: As a business, how much of the cost of energy bills do you pass on to customers?

This is a question for individual operators to address.

5.D5: How might your company or sector be affected and would be there any impact on your profit margins?

It is very difficult to assess the impact of the proposals on the power sector, as they represent only part of the Government's proposed Electricity Market Reform. The effect on individual companies will depend on the composition of their generating portfolios.

5.D6: Do you have any comments on the assessment of equality and other impacts in the evidence base of the Impact Assessment, included at Annex D?

We consider that there are flaws in the analysis that underpins the Impact Assessment, many of which stem from insufficient attention paid to sensitivities. The following issues in particular are open to question:

- the future coal price;
- the assumptions around the timing of CCS development;
- the assumption that all renewable energy targets are met.

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