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Energy market reform proposals

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Executive summary and synopsis

On 16 December 2010 the Government published its proposals for substantial changes to the UK Electricity Market in the form of a *Treasury paper on a Carbon Price Floor* and a *Department of Energy and Climate Change paper on Energy Market Reform* stating the intention that "In the new, reformed UK electricity market, the economics of low carbon will stack up like nowhere else in the world." [1]

The latest market reform proposals are significantly inter-related to other initiatives, most particularly *Ofgem's Liquidity Review* in respect of which an update by way of an *Open letter on Liquidity in the GB Power Market* was published on 3 December 2010.

Due to the powers devolved to the Scottish and Northern Ireland Assemblies, the position for Scotland and Northern Ireland is not yet clear, although the Government states that it is working closely with the Devolved Administrations.

Before looking at the detail of the proposals it is worth asking why any Government would want to make a market which is funded by its residents (commercial and domestic) "stack up like nowhere else in the world". Put simply, there is a competition for capital as nation states rush to improve their energy infrastructure to deliver security of supply and decarbonisation at an affordable price. This improvement is estimated to cost £75 billion in new generating assets alone in the UK in the next decade. The vast majority of this is envisaged to be in the offshore wind and nuclear power sectors. By making the underlying UK regime as attractive as possible the theory is that investors (both established and new and debt and equity) will be more likely to invest in the UK than in other jurisdictions and do so with investment returns that maximise affordability.

The key question therefore is will the proposed reform produce a regime that is better suited to attracting the type of capital in the amounts necessary to meet the Governments aims of security of supply, decarbonisation and affordability?

The proposals put out to consultation 4 principal changes: (a) an underpinning of the carbon price by reference to an escalating target price payable by power stations that generate using fossil fuels; (b) a Government backed hedge to the wholesale electricity price for new nuclear and renewables electricity generators; (c) a capacity payment to incentivise and bring forward investment in demand and supply side management services; and (d) an absolute limit on the amount of carbon dioxide that any new generating plant can emit in any year.

1 _ http://www.decc.gov.uk/en/content/cms/consultations/emr/emr.aspx

On paper, there is coherence between these proposals:

- A higher carbon price should feed through into higher wholesale electricity prices which disproportionately benefits those generators who are not exposed to the carbon price (i.e. renewables and nuclear).
- A government underpinning of the wholesale electricity price could mean that annuity seeking investors who are not vertically integrated electricity utilities would find investment in UK electricity generation more attractive as their exposure to the wholesale electricity price is reduced.
- Because the proposed government hedge is structured as a CfD[2], if a higher carbon price in fact produces higher wholesale electricity prices than anticipated the Government receives the benefit. Equally, once the price setting plant in the UK is not fossil-fuelled, investors in new low carbon generation do not need to worry that the wholesale electricity prices they can access may collapse.
- The government hedge is contained in contract and not in statute because this is perceived to offer greater certainty to investors.
- By maintaining the wholesale electricity market and structuring the Government hedge as a CfD, generators are incentivised to be available at times of peak demand and to invest appropriately in maintenance to ensure long-term availability and efficiency.
- As renewable intermittent generation grows as a percentage of installed capacity and new build nuclear plants increase the single loss load figure, it becomes more important for an electricity network to have both robust demand and supply side management measures in place. They do not exist in the UK at present and their development will call for investment that would not be adequately rewarded through the current regime which remunerates generators only for generation and not availability (ignoring for the time being the measures that National Grid put in place in relation to reserve capacity). Some form of capacity mechanism is therefore required to bring forward this investment over the same time horizon as the envisaged investment in renewable and new build nuclear generation.
- The cap on emissions limits is really a fail-safe intended to under-line to investors in nuclear and renewables generation that new generation from coal on an unabated basis will not be encouraged.

2_Under the preferred market reform proposal

However, as we scratch the surface of the proposals there are some interesting questions and potential anomalies that emerge which should be considered, answered and addressed during the consultation period. For example:

– Attracting new investors to low carbon generation in the UK, maximising the availability of project finance debt and reducing the risk premium sought by investors by removing the risk of fluctuations in the wholesale electricity price is generally pro-investment[3]. However, the proposed structure of the Government hedge means that investors will have to form the view that their generating asset will access the average electricity wholesale price (or at least within a given percentage of the average wholesale electricity price). Leaving aside trading strategy efficiencies this would seem to be less likely for a non-peak coincident form of generation such as wind. The CfD proposal seems better suited to nuclear power than renewable intermittent generation although differences in the characteristics of types of generation could be addressed through having different tenors and strike prices in the CfDs for the different technologies.[4]

– Annuity seeking investors in new low carbon generation projects will, in addition to hedging their exposure to the wholesale electricity price, also be concerned to understand how balancing risk[5] and route to market concerns will be addressed. In wind projects to date involving investors who are not vertically integrated utilities these risks have typically been addressed
in a power purchase agreement between the generator and a utility.

– To address the topics that are raised in the preceding 2 bullet points it seems, at least, more likely than not that utilities will still need to enter into power purchase agreements with independent wind farms in order to deliver the affordable investment envisaged. Without the pull of the Renewables Obligation and the lack of any supplier obligation to purchase from defined technologies, it is not immediately apparent that the CCL regime is a sufficient tax and regulatory incentive on the utilities to do this. Even if a utility is prepared to enter into a PPA with an independent renewables generator this pattern of circumstances and the imminent arrival of investment opportunities in new build nuclear power and Round 3 wind projects for utilities seems to set an independent renewables generator at a disadvantage in any negotiation of such a PPA.

– There are significant other risks involved in developing wind farms (both on and offshore) and nuclear power which are not addressed by the proposals and which may act as an impediment to attracting new sources of capital to new build nuclear and renewables. For example, unlike thermal plant and many social and transport infrastructure developments, fixed price date certain turnkey construction contacts for nuclear plant and offshore wind are either not

3_This is of course why the Government has proposed its hedge to the wholesale electricity price

4_ Chris Huhne's statement in relation to subsidies and nuclear power of 18th October, 2010 makes it clear that support does not need to be identical between different types of generation butsimilar.

5_The risk that the plant does not generate as much as expected for any reason in any given 30 minute period.

available or are prohibitively expensive. This being the case there is a growing view in the UK that the major utilities operating in the UK will need to shoulder the majority of the construction phase equity requirements for large scale low carbon generation and that the purpose of the regime proposed in the consultation is to create an environment within which they have the certainty necessary that in due course they will be able to recycle this construction phase equity through disposals to new investors.

– The consultation contains no reference to this but it will be important that consultation responses properly consider how to incentivise any such refinancing and ensure that the proceeds are then re-invested in the next phase of investments requirement in the UK generating sector.

– Rating agency treatment of bank-financed developments in which a utility has an equity stake and also underpins the development's revenue with a PPA will need to be confirmed given the tensions between accounting off-balance sheet treatment and rating agency on-credit treatment that recent transactions have revealed. If these tensions remain then this could be a further impediment to the availability of the power purchase agreements referred to above and therefore the refinancing referred to above.

– The suggestion that including the Government hedge to the wholesale electricity price in a contract increases certainty for investors when compared to including such a hedge as a matter of background law is at best legally dubious. If the hedge agreement contains a developed change in circumstances clause and investors take the view that the government will not legislate subsequently to remove its effect then this would be the case. However, to presuppose that subsequent legislation will not affect the contract is itself to assume that the very risk being mitigated (political risk through subsequent change in policy/legislation) will not arise.

There are a number of questions raised by the detail of the proposals and these are outlined in the more detailed "Summary of Consultation Proposals" and "Commentary" sections below.

In addition to preparing a response to the consultation, market participants will also wish to consider their position under existing and future transactions. Some particular issues to look out for include:

Thermal generators – Review change of law/change in taxes provisions in contracts which apply after 1 April 2013 to check for pass-though of *CCL carbon price support rates*.

Coal plant – consider potential effect of Emissions Performance Standard on proposals for life-extensions and co-firing of biomass.

Consider effect on Grid Trade Master Agreement trades.

Renewable Generators – Review bespoke change of law provisions in power/ROC purchase agreements in the light of the proposed market changes including considering the possible effect of a Fixed ROC situation where the ROCs are bought at a fixed price by a central agency.

New renewable power purchase agreements also need to allow for possible choice between FIT and ROCs between 2013 and 2017.

Summary of consultation proposals

The Government's objectives in undertaking electricity market reform are to secure:

– Security of Supply
– Decarbonisation
– Affordability

The Government wants to ensure that the electricity industry is decarbonised by the 2030s so that electrification of heat and transport can follow. Demand for electricity (notwithstanding energy efficiency programmes) is expected to increase and potentially as much as double by 2050. As over 19GW of nuclear, coal, oil and gas plant is scheduled to close over the coming decade, it is expected that £70 to £75 billion of new plant will be required by 2020. In the absence of any intervention, capacity margins are likely to fall in the latter part of the coming decade to below 10%[6]. In addition, the Government assesses that meeting its share of the European Union target for renewable energy by 2020 requires 30% renewable generation in the UK electricity market.

The Government is concerned that current market signals "may not be strong enough to overcome the additional uncertainty that arises as we deploy intermittent renewables and decarbonise". It recognises that "Low carbon generation typically has high construction (capital costs) and low operating costs, and as such are wholesale price takers. It is therefore difficult to make an investment case for them in a market where wholesale electricity prices are predominantly set by the short run marginal costs of gas and coal plant, even if the carbon price was "high enough for their levelised costs to be similar".

There are four main areas of reform proposed which are discussed further below:

- **Carbon Price Support** – to be effected by imposing additional taxes, referred to as "carbon price support rates", on fossil fuels used in electricity generation (which will be different to the main Climate Change Levy rates). The intention is to "top-up" the effective carbon price UK generators currently pay under the EU ETS, to a trajectory more consistent with DECC target levels and thereby give certainty as to the long-term cost of carbon in UK power generation (and therefore the relative advantage of low-carbon power sources). The level of tax will depend on the carbon content of the relevant fuel and how far the EU ETS price is below desired levels. This will (unless EU ETS outturn prices render it unnecessary) create additional cost to thermal generators which will raise UK wholesale electricity prices while fossil fuel plant is the price setter.
- "**Feed-in Ta riffs**" – for low carbon generators (in accordance with the no separate subsidy for nuclear policy of the Coalition), the Government favours offering long-term Contracts for Differences (which would not be a feed-in tariff as normally defined in the industry) with variable payments in respect of electricity sold to third parties calculated by reference to the difference between the agreed tariff and average wholesale electricity prices (with generators

6_The Government identifies that a margin around 10% is generally considered to provide an appropriate balance between the costs of spare capacity and the security of supply benefits.

entitled to keep the upside if they sell above average wholesale price), although it states that an alternative of a premium payment for electricity sold of a fixed amount above the wholesale price could also be considered but this is not the preferred approach on grounds of cost-effectiveness.

- **Capacity Payments** – the Government proposes a targeted mechanism with demand side participation.
- **Emissions Performance Standard** – a regulatory annual limit on the amount of carbon dioxide released into the atmosphere from a new source of electricity generation. This would be set at a level intended to prevent new unabated base-load coal fired generation without Carbon Capture and Storage (CCS), but would not currently affect gas-fired plant.

Quick reference guides for the consultation proposals, a summary of how they affect different types of plant and a summary of the 2 consultation timetables are included as annexes to this note.

Commentary

Setting the Strike Price for Contract for Difference

It will not be easy to establish an appropriate strike price for a Contract for Difference. Certain types of low carbon generation, such as nuclear, may also require longer contracts than others. Chris Huhne, the Energy and Climate Change Secretary, has suggested that the terms might initially need to be established in negotiation with the industry, but ultimately the preference would be for auctions.

Auctions

An auction may present particular challenges for different types of low carbon technology. The consultation contemplates, for example, that early stage technologies with higher costs such as offshore wind might need specific additional premiums (an interesting question is whether there would be differentiation for first of a kind nuclear and subsequent nuclear and whether this would apply in connection with different reactor technology.) If there were technology specific rather than technology neutral auctions then the Government would be overtly involved in selecting the mix of particular technologies and the Consultation Paper suggests this would entail the Government specifying a certain number of GW of onshore wind, offshore wind, nuclear and other technologies.

If an auction is used, further questions arise as to whether this results in 'pay as bid' or payment at the 'marginal price'. The consultation discusses the comparison of the Non-Fossil Fuel Obligation (NFFO) auctions and the risk of the 'winners curse' where in order to win the auction bidders may bid too low and find that the project is not ultimately realisable at that level of return. An associated issue is whether the auction winner is subject to any penalties for not delivering the project within a particular timetable. Penalties would present particular issues in the current UK market where the difficulties of obtaining planning consent and grid connection for low carbon generation projects may represent, as recognised by the Consultation Paper[7], a much greater influence on the ability to obtain finance and realise a project.

The timing of auctions will present challenges for investment decisions. As highlighted above, bidders in an auction who require bank financing or otherwise wish to avoid exposure to balancing risk and fluctuations in the wholesale electricity price and may need to sign up PPAs with utilities/ suppliers in order to mitigate balancing risk, route to market issues and hedge their exposure under the CfD to the average electricity price payable to the generator under such contract (the **reference price**)[8]. This will almost certainly require them to accept payment for their power at a discount to the reference price and the extent of this discount will affect the strike price they will require to meet their target returns. It therefore seems likely that bidders may need to sign up PPAs (or at least binding term sheets) before any auction in order to establish the price they will need to bid into the auction.

7_See Energy Market Reform Consultation December 2010 page 35.

8_Depending on the approach taken in the government CfD to change in law risk the market PPA may also need to address changes in law (at least to the extent that they affect the market structure)

For offshore wind there is also the complication that sites for Round 3 have already been awarded and for nuclear that the available sites are identified in the National Policy Statement and already owned by relevant utilities. It is not clear how Government will avoid the risk of stranded capacity/ an investment hiatus if a licence holder or land owner determines that it will not develop as a result of the outcome of the auction. In this regard, the termination provisions in a typical Crown Estate Lease relating to build-out will need to be considered for future offshore wind projects.

Ability to realise Average Electricity Price

The difference payments under the Contract for Differences are proposed to be calculated by reference to average electricity market prices with generators allowed to keep the upside if they sell above average electricity price, but suffering downside if they are only able to sell below the average electricity price.

The downside risk of selling below the average electricity price is more substantial for intermittent low carbon technologies such as wind power whose power is likely to be less attractive to the market (particularly in the absence of a supplier obligation to buy such power) and whose imbalance risks will only be increased by the proposed cash out price sharpening (see Proposals for Cash Out box below). Wind generators are unlikely to be able to capture all the market price peaks because of their inability to control their generation profile and indeed, if wind generation comes to constitute a large share of the market, some price peaks may be specifically caused by a periods of low wind. These downside risks are even greater for independent market players in comparison to vertically integrated utilities.

It is recognised in the Consultation Paper that exposure to electricity price risks "may be harder to manage for independent generators with smaller portfolios or for investors in large individual low-carbon generation projects, therefore a fixed payment scheme might have a bigger impact on reducing barriers to entry in the wholesale market"[9]. However the Consultation Paper nevertheless rejected a fixed feed-in tariff.

Change of Circumstances

There is no discussion in the Consultation Paper as to whether change of circumstances provisions might be included in the Contract for Difference to adjust for changes that affect the assumed financial position of the Generator. It may be that Government assumes that such matters will be dealt with (if at all) in the market facing power trading arrangements of the Generators. If the Contract for Differences is intended to protect investors from regulatory uncertainty and political change risk then provisions similar to those in emerging market power purchase agreements for price adjustment or termination with a compensation payment following certain types of change in law may need to be considered.

9_See Energy Market Reform Consultation December 2010 page 58

Two Way Payments/Credit Support

It is clear that the proposed CfD will be "two-way" – the Generator must make a payout to the Government agency if the reference price is above the strike price. The Government agency will presumably need to consider generator credit risk but costs would be increased if generators were required to provide margining credit support against the risk of such payments.

Credit will also be a concern for generators. It is unclear from the Consultation Papers how the funding for the Government agency that will sign the CfDs will be ensured and whether there would be any risk of it not having sufficient funding (as was addressed in relation to NFFO contracts) to meet its obligations as they fall due.

Calculating Average Electricity Price

In addition to the difficulties of setting the strike price for the Contract for Difference, it is difficult to establish what constitutes Average Electricity Price in a market which does not have a pool or a significantly exchange based trading structure. After the abolition of the pool as part of the New Electricity Trading Arrangements (NETA) power in the UK is traded bilaterally rather than centrally and there is no longer a price available which represents the average price at which all electricity is traded in the market. (Generators (and their financiers) who had to realign their previous contracts for differences when NETA was introduced will be familiar with the problem of the absence of a representative market price in the NETA market structure.)

The price of the Balancing Mechanism does not (contrary to some suggestions in Box 6 on page 60 of the Consultation Paper) represent the average wholesale electricity price. The various proposals for sharpening the cash out price or reforming the reserve market (see below) may alter the calculation of this price, but will not necessarily assist generators in their ability to obtain those prices. In fact, a sharper cash out price is likely to disadvantage intermittent low carbon generators (absent any value in just spilling all their power).

The volumes of UK power traded on the APX and NE2X markets also represents only a small proportion of the overall market.

Proposals for Cash Out/Reserve Reform/ Intermittent Generation[10]

There are three groups of actions relating to balancing that the Government has considered (separately to the Energy Market Reform Consultation):

1. reforming the calculation of cash out payments;
2. improving the System Operator (SO)'s approach to procuring reserves necessary to maintain system balance by a short term reserve market[11]; and
3. actions to better manage balancing of intermittent renewable generation[12].

1. The following are options ***for cash out reform***:

– **changing to a single cash out price**: There are currently different cash out prices for selling and buying electricity. Although this provides a strong incentive for balancing it may not be truly cost reflective. An alternative would be a single price (or one with a fixed spread between buy and sell);

– **changing to more marginal pricing**: The current scheme is "pay-as-bid" and the imbalance price is the average of the most expensive 500MWh of balancing actions. A scheme closer to marginal pricing would result in higher and more cost-reflective prices at times;

– **more effective allocation of reserve contract costs**: The costs associated with the SO purchasing STOR are allocated using the previous year's reserve usage as a proxy. These costs could be better targeted to the periods in which the reserve is actually used and so enhance cost reflectivity; and

– **putting a price on currently non-costed SO actions**: Customers could be compensated for involuntary voltage reductions and power cuts and the costs included into the cash out price so that these actions (effectively free) are properly reflected.

10_See Energy Market Reform Consultation December 2010 page 80 to 81.

11_See Energy Market Reform Consultation December 2010 page 81

12_http://www.ofgem.gov.uk/markets/whlmkts/discovery/Documents1/Brattle%20report%20-%20Alternative%20Trading%20Arrangements%20for%20Intermittent%20Renewable%20Power%20-%20PDF.pdf

2. The proposal for a ***reserve market*** is a short-term market (for example, day-ahead) run by the system operator to procure reserve resources. This would enable the value of reserve to be factored into the cash out prices in a way that more accurately reflect conditions on the day, and therefore cash out prices will be better targeted at the participants causing any shortfall. These sharper price signals should enhance security of supply. To avoid distortion, resource that is receiving a capacity payment (eg under STOR) would need to bid its full costs into the reserve market. One option to ensure this would be that the SO is responsible for bidding the reserves they have contracted for into the market.

3. Finally, Government has considered actions to better manage **balancing of intermittent renewable generation**. Wind generation, due to its intermittent nature, is more exposed to being out of balance and faces greater risk of paying cash out penalties. Government proposes to wait and see if such aggregation services are developed and provided privately, as a result of existing incentives to reduce balancing costs and an increasing opportunity for aggregation as the share of intermittent generation increases.

Liquidity

Liquidity is recognised in the Consultation Paper[13] as "particularly important in the context of the EMR reforms because:

– premium FITs and FITs with CfDs do not take away off-take risk from generators, and FITs with CfD rely on an effective reference price;

– targeted capacity mechanisms rely on effective functioning of the wholesale market to provide investment signals to most resources; and

– effective and competitive markets help keep energy prices as low as possible, consistent with the need for investment to meet climate change and energy security objectives."

It is also recognised that liquidity in the Great Britain wholesale electricity market is low in comparison with both other commodity markets and electricity markets in a number of other European countries.

Ofgem is undertaking a separate programme of work to increase liquidity in the wholesale electricity market[14] and published an open letter with an update on its review on 3 December 2010[15].

Ofgem has urged the industry to take its own actions to improve liquidity, and is monitoring the developments to see if progress is sufficient. If progress by Spring 2011 is inadequate, Ofgem intends to bring forward measures to improve matters. (See Liquidity Review box below)

These measures have the potential to make significant changes to the current market.

Since the liquidity of the electricity market is crucial to enable generators to assess the strike price for the Contract for Difference, the Liquidity Review process is an important inter-dependency for the other reform proposals.

13_See Energy Market Reform Consultation December 2010 page 110.

14_See Liquidity Proposals for the GB wholesale electricity market, 22 February 2010, Ref: 22/10

15_http://www.ofgem.gov.uk/Pages/MoreInformation.aspx?docid=95&refer=Markets/WhlMkts/CompandEff

16_http://www.ofgem.gov.uk/Markets/WhlMkts/CompandEff/Documents1/Open%20letter_Liquidity%20in%20the%20GB%20power%20market_update%20and%20next%20steps.pdf

17_See Energy Market Reform Consultation December 2010 page 110 to 111

Liquidity Review

Ofgem are considering four possible measures to improve liquidity:[16]

– **obligations requiring large generators to trade with small/independent suppliers**, a licence condition would be placed on large generators to require them to trade directly with small/independent suppliers. For example, this could involve requiring large generators to offer a wider range of smaller quantities of generation more suitable for smaller suppliers;

– **market making arrangements**, supported by a licence obligation on the Big 6 to provide electricity in defined products: Under this option the Big 6 would be obliged to provide electricity to a "Market Making Agent" who would make this available to market participants via a trading platform;

– **mandatory auctions of generation**, supported by a licence condition on all large generators to offer a certain percentage of their output into an auction. The auction would focus on the prompt market with the aim of developing trusted reference prices and financial derivatives, or longer term products; and

– **self-supply restrictions**, on the large vertically integrated utilities, which would limit the extent to which they may supply their own retail business from their own generation output and would force a proportion of their requirements to be traded through the market.

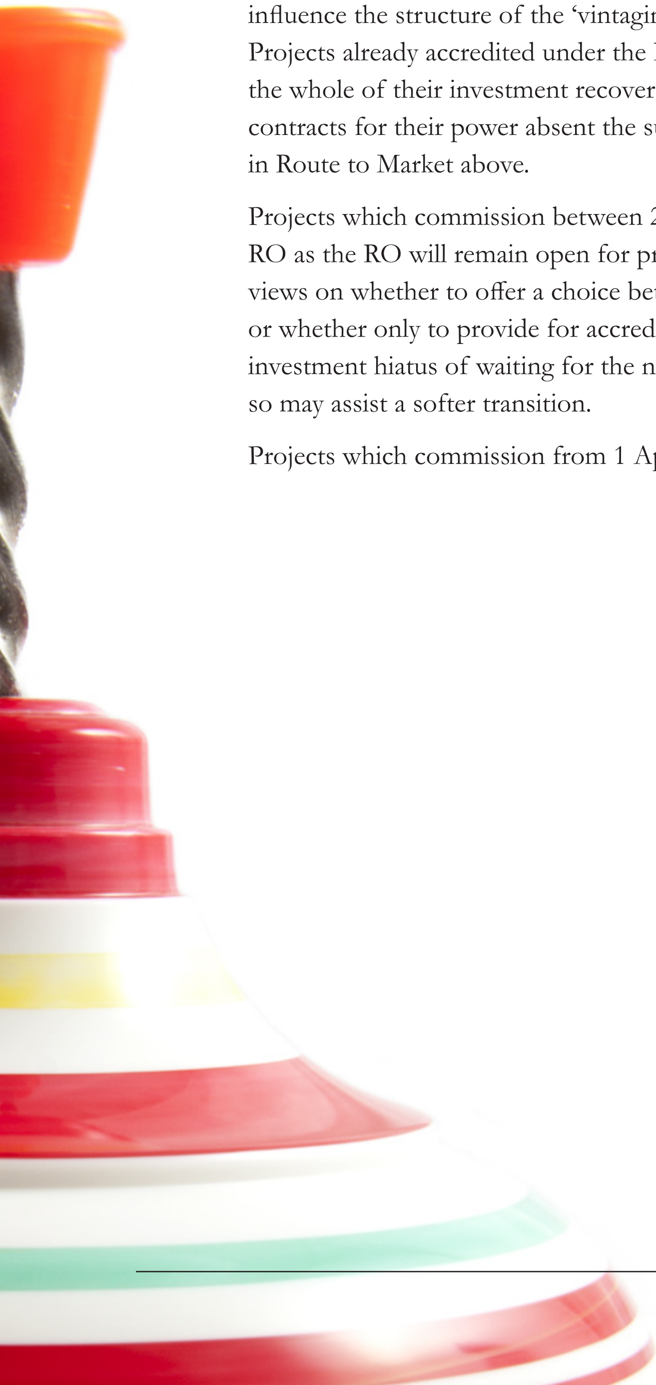
Route to Market/Access to Power Purchase Agreements/Financing

Another key feature introduced by NETA is the absence of a clear route to market for generators. This creates particular difficulties for independent generators, new market entrants and their financiers.

Debt financiers and new market entrants invariably look for long term power purchase agreements and it is not clear that the Energy Market Reform Proposals will give suppliers any incentive to enter into long term power purchase arrangements.

The Renewables Obligation (RO) currently incentivises suppliers to enter into power purchase agreements with renewable generators. There is no equivalent incentivisation for new plant which will not operate under the RO regime.

In the absence of any other incentive to do so, it is difficult to see why suppliers would enter into long term power purchase agreements particularly with intermittent generators, compounding the risk of for such generators of achieving the average price discussed above. Power purchase agreements have also offered generators a means of transferring imbalance risk to offtakers and this is likely to continue to be an important risk transfer issue, particularly if the proposals for cash out reform (see Proposals for Cash Out box below) result in higher prices. There remains some incentivisation for suppliers to obtain Levy Exemption Certificates (LECs) and Renenewable Electricity Guarantee or Origin Cerficates (REGOs) but it is not clear that these incentives will be sufficient to enable renewable generators to obtain power purchase agreements on sufficiently attractive terms.



Transitional Arrangements for Renewables

Projects accredited under the RO will continue to receive Renewable Obligation Certificates (ROCs). However the value of those ROCs may be affected by the way in which the RO is 'vintaged'. One proposal is to fix the price of a ROC and require a delivery agent to buy them (Fixed ROC proposal). The Fixed ROC proposal refers to introducing the fixed price at the next banding review implementation date although the purpose of any change prior to 2017 is not clear unless to provide a comparator for choice with a Feed in Tariff in the period after 2013/14. The Fixed ROC proposal has potential to significantly disrupt existing power purchase agreements and renewable generators will wish to check the change of law clauses in their existing power purchase agreements and seek to influence the structure of the 'vintaging' of the RO in such a way as to minimise any adverse impact. Projects already accredited under the RO whose existing power purchase agreements do not run for the whole of their investment recovery period may experience more difficulties in placing new contracts for their power absent the supplier's need for associated ROCs, for the reasons discussed in Route to Market above.

Projects which commission between 2013/14 and 2017 will be able to seek accreditation under the RO as the RO will remain open for projects accredited by 31 March 2017. The consultation invites views on whether to offer a choice between RO and the Feed In Tariff between 2013/14 and 2017 or whether only to provide for accreditation under the RO. A choice may assist to avoid an investment hiatus of waiting for the new regime, if that is considered to be more favourable, and so may assist a softer transition.

Projects which commission from 1 April 2017 will only be eligible for the CfD Feed In Tariff.

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ANNEX 1: *Quick reference guide to consultation proposals*

Carbon Price Support

Proposal

Government will remove the exemptions from the Climate Change Levy (CCL) for fossil fuels used to generate electricity and tax these at rates to take account of their average carbon content (which will be different to the main Climate Change Levy rates). Government also proposes to reduce the amount of fuel duty that can be reclaimed when oil is used to generate electricity.

The obligation to register and account for the tax will be upon the supplier of the fossil fuel.

Generators may need to complete an adapted form of PP11 certificate.

Generators importing fossil fuels from outside the EU would have the choice of either accounting for CCL at the time of importation or registering for CCL and accounting for the levy though their CCL return.[17]

Rationale

To "top-up" the effective carbon price resulting from EU ETS.

Requires less public expenditure as funded by tax system.

Aligned with the 'polluter pays' principle.

Outstanding Issues

Rate? – Treasury are consulting as to different scenarios for price trajectories, with the tax-inclusive price of carbon being raised to £20, £30 or £40/tCO2 by 2020 and £70/tCO_2 in 2030. The indicative levels of tax resulting from this are set out in Table 1 of the Impact Assessment[18] DECC's illustrative figure is of a tax equivalent to £10/tCO_2 (above the EU ETS target level) translating to £1.84/MWh for gas plant (being the price setter).

Rate escalation and reviews?[19] – Options include

- – a rate escalator set at levels to achieve a specific carbon price trajectory over the life of a Parliament consistent with an overall target for the carbon price in 2020; or
- – annually adjusted CCL rates and fuel duty rebates that take account of short-term trends in the carbon market and economy to ensure closer targeting of the Government's carbon price trajectory from year to year; or
- – rates set annually based on a carbon market index averaged over a specific annual or biennial period to reflect future carbon prices.

The Government's preferred option is to increase the rates incrementally from 2013 until the tax-inclusive carbon price is consistent with the Government's target price trajectory.

How to adjust for changes to EU ETS?

Exchange Rate/Discount Rate?

17_See Impact Assessment on Treasury proposal page 8 paragraph 26.

18_See Impact Assessment on Treasury proposal page 6 Table 1.

19_See Treasury Consultation December 2010 page 26.

Feed In Tariff (FIT)

Proposal

Contract for Difference (CFD) to be offered by a central body to provide low carbon generators a guaranteed tariff calculated as the difference between the strike price and the average price in the wholesale market (with generators entitled to keep the upside if they sell above average wholesale price).[20] The duration of the contract is yet to be decided (eg 15-20 years). This replaces the 'pull' of the RO.

Alternative of a Premium FIT to give payment of a fixed amount above the wholesale price could also be considered for ease of implementation, but this is not the preferred approach as it is considered to be less cost-effective and risks over-rewarding generators, for example if the Government were to change the carbon price support level and this fed through as an uplift to electricity prices.

Rationale

Contract will be legally enforceable by generators so may give additional comfort with respect to regulatory risk.

Reduces need for an excessively high carbon price (which may have negative impact on energy intensive businesses at risk of carbon leakage). CFD automatically adjusts for carbon price included in average wholesale price.

Keeping the price signal means that low carbon generation has an incentive to carry out maintenance at times when demand and prices are low (whereas the alternative of a Fixed Feed In Tariff which replaced revenues from selling electricity in the market would remove the price signal).

Alternative of a low carbon obligation is rejected as this would have an equivalent economic effect to a Premium FIT but with greater complexity. Renewables Obligation is considered not cost effective as its upside is not attributed full value by institutional investors and financers. Alternative of a regulated asset base is rejected as that would transfer virtually all risks from the generator to the consumer including construction risk.

20_See Energy Market Reform Consultation December 2010 page 53 Figure 8.

Outstanding Issues

How to set the CFD strike price?

Potential auction structure – technology neutral or technology specific?[21] Government suggests if technology neutral auction may need specific premiums on top for early stage technologies eg offshore wind. Technology specific will require the Government to specify a volume for each relevant type of technology.

Reference price – how to measure what constitutes average wholesale electricity market price? Government recognises electricity market does not currently have sufficient liquidity although this is the subject of a separate Ofgem review.

Ability of generators to achieve average market price? Intermittent generators in particular may find it difficult to achieve this. Query incentive for suppliers to enter into power purchase agreements.

How to 'vintage' the Renewables Obligation (RO)?[22] Government proposes to close the RO to new generation from 1 April 2017. It is consulting on how to calculate the amount of the RO post 2017 for example by adapting the headroom calculation or whether to fix the price of a ROC and require a delivery agent to buy the ROCs from the generator at that fixed price.

Whether to offer renewable generators a choice between RO and Contact for Difference between 2014 and 2017?

How to fund the central body acting as counterparty to the Contract for Difference?

Alternative option of Premium Feed-In Tariff? This is not favoured by Government.

21_See also Dieter Helm, (October 2010, Policy Paper Market reform: rationale, options and implementation, http://www.dieterhelm.co.uk/sites/default/files/Market%20reform%20October%20paper.pdf)

22_See Energy Market Reform Consultation December 2010 Annex A.

Emission Performance Standard (EPS)[23]

Proposal

Annual regulatory limit on carbon dioxide emitted by individual new plant.

Not to apply EPS retrospectively to existing plant unless it undergoes significant life extension or upgrade.

The level of EPS in place at the point that a power station is consented remains the level which is relevant for the economic life of that power station.

EPS to be applied to existing plant which undergoes a significant life extension or upgrade (excluding plant which install Selective Catalytic Reduction or retrofit CCS).

Whilst the EPS would be technology neutral it is intended the level will presently only affect unabated coal plant.

Exceptions for supply emergencies, to allow coal plant under tightly defined circumstances to turn off their CCS equipment at times of exceptional demand.

Rationale

Prevent unabated new build coal plant whilst allowing for demonstration of all CCS technologies.

Complement the regulatory carbon capture ready requirements.

Outstanding Issues

Level of EPS?[24] DECC is consulting as to the level of the EPS, between alternative levels which imply 25% and 40% CCS for coal plant.

– a level equivalent to 600g CO2/kWh, consistent with demonstrating post-combustion CCS on a new, supercritical coal-fired power station;

– a level equivalent to 450g CO2/kWh, with specific exemptions for plant forming part of the UK's CCS Demonstration Programme or benefiting from European funding for commercial scale CCS projects.

The levels are intended to be set at present so as not to apply to new gas plants although the Consultation raises the prospect of future tightening.

Potential differentiation for co-fired biomass? Government wishes to design the EPS to support the co-firing of an appropriate level of biomass. The Consultation suggests that one option would be to 'zero rate' or otherwise differentiate, the emissions from biomass fuel when calculating plant carbon dioxide emissions[25].

23_See Energy Market Reform Consultation December 2010 page 69.

24_See Energy Market Reform Consultation Document December 2010 page 70.

25_See Energy Market Reform Consultation Document December 2010 page 75 paragraph 97.

Capacity Mechanism

Proposal

Obligation to be placed on a central body to maintain a set capacity margin. Margin to be set by volume.

Tenders for the additional capacity needed to make up the shortfall between level of capacity provided by market and centrally determined margin.

Targeted rather than general capacity payments.

Central body can select specific technology to determine the mix (eg OCGT). (This effectively involves Government in technology choice.)

To include demand side response (eg supermarket chain switching off refrigeration) – so called 'negawatts'.

Possibly different approaches to different resources (eg separate tender for Demand Site Response and generation).

May be separate treatment for particular geographical areas.

Rationale

The other measures will not be sufficient to address all of the security of supply concerns identified.

Outstanding Issues

Risk of market distortion ?

– Slippery slope effect – risk of lack of investment outside the capacity market.

– Effect on peak prices – other capacity may not receive adequate return.

Last resort model or economic dispatch model? – Note that the consultation document suggests that if the capacity resource were only used in the last resort or if the capacity payments in an economic dispatch model are accurately fed back into the 'cash out' price, then market distortion would not be significant. Although, under the current NETA market structure, most power is traded outside the 'cash out' price.

Interaction between generation and demand side participation? Should there be separate tenders?

Which generators are eligible to participate? – eg existing generation, plant that would otherwise close, new or upgraded plant?

Tenor of contracts?

Interaction with other EU markets via interconnectors?

26_See Energy Market Reform Consultation December 2010 pages 94 and 119.

ANNEX 2: *Particular impacts on generation type*

Type	Carbon Price Support[27]
Oil	Reduction in ability to reclaim fuel duty.
Gas	Introduction of charge on gas used to produce electricity.
Coal	Introduction of charge on coal used to produce electricity.
CCS	Government considering a partial relief for fossil fuels used in CHP plants to reflect the proportion of carbon dioxide abated, subject to State Aid approval.[29]
Biomass	
CHP	Fossil fuels burnt in CHP stations will be subject to tax at the relevant carbon support rates regardless of the CHP Quality Assurance Rating.
	However Government invites views on whether it is desirable to provide additional preferential treatment for CHP and, if so, the best way of achieving this.[32]
Renewables Generally	
Offshore Wind	
Nuclear	
Interconnectors	There will be no change to the tax treatment of imported electricity in line with EU excise and energy tax directives. Electricity exported from the UK will continue to be exempt from CCL, but fossil fuels used to generate electricity which is then exported will be liable to tax.[35]
	Likely to result in increased incentive for importing electricity and reduced incentives to export electricity.

27_See also Treasury Consultation December 2010 page 24 Table 4.C.

28_See Energy Market Reform Consultation Document December 2010 page 75 paragraph 97.

29_See Treasury Consultation December 2010 page 23 paragraph 4.31

30_See Energy Market Reform Consultation Document December 2010 page 75 paragraph 97.

31_See Energy Market Reform Consultation Document December 2010 page 128.

Energy Market Reform	Other
See general discussion above.	
See general discussion above	
Emission Performance Standard designed to prevent new build of unabated coal fired plant.	
Emission Performance Standard will also apply to existing plant which undergo a significant life extension or upgrade (excluding plant which install Selective Catalytic Reduction or retrofit CCS).	
Government wishes to design the Emission Performance Standard to support the co-firing of an appropriate level of biomass. The Consultation suggests that one option would be to 'zero rate' or otherwise differentiate, the emissions from biomass fuel when calculating plant carbon dioxide emissions.[28]	
Emission Performance Standard set so as not to prevent the Carbon Demonstration Programme covering the full range of approaches to carbon capture.	
Government considering whether to 'zero-rate' or otherwise differentiate the emissions from biomass fuel when calculating carbon dioxide emissions for the Emissions Performance Standard.[30]	Biomass electricity will need to have a carbon intensity of 285.12 $kgCO_2$/MWh or lower to be eligible for ROCs from April 2013.
	Sustainability Criteria will need to be met from April 2013 by generators of 1MW and above except for biomass wholly derived from waste.
	In relation to Scotland, grandfathering for biomass and waste technologies is subject to a separate consultation.[31]
	New stations as of 2013 will be eligible for support under both the RO and the Renewable Heat Incentive.
	Further CHP uplift to be considered in the light of the introduction of the Renewable Heat Incentive as part of the RO Banding Review.
RO will remain open for projects accredited by 31 March 2017.	RO Banding Review brought forward by 12 months. Government to announce banding scenario for consultation in Summer 2011 and confirm Government response in Autumn 2011. Changes to take effect from 1 April 2013 for most technologies and 2014 for offshore wind.
Consultation on whether to offer a choice between RO and FIT between 2013/14 and 2017.	
Consultation on how to 'vintage the RO' including how to calculate the obligation after 1 April 2017 or whether to provide a Fixed ROC price.	
Risk of greater exposure to higher cash out prices for intermittent generation. Discussion of aggregators.[33]	
The The consultation floats the idea of a technology-neutral auction for a single tariff level for all low-carbon generation, coupled with additional technology specific premia for early stage technologies (such as offshore wind). This avoids the Government making technology choices by specifying how much capacity of each of onshore wind, offshore wind, nuclear etc. is required. However, DECC's figures[34] for "first of a kind" and "Nth of a kind" costs suggest that offshore wind may not be competitive on this basis, with a risk of a "winner takes all" outcome which does not result in a beneficially diverse technology mix.	Introduction of phased support from 1 April 2011. Generators will be able to register up to 5 phases each for up to 20 year support (subject to a minimum of 20% of proposed total installed capacity being in first phase).
	RO Banding Review to take effect from 1 April 2014.
See general discussion above.	
	Ofgem is developing a new regulated approach to interconnector investment which will be consulted on early in 2011.[36]

32_See Treasury Consultation December 2010 page 22 paragraph 4.29.

33_See Energy Market Reform Consultation December 2010 page 81

34_Energy Market Reform Consultation December 2010 – Figure 2, pg 28.

35_See Treasury Consultation December 2010 page 25 paragraph 4.36 and 4.37.

36_See Energy Market Reform Consultation Document December 2010 page 83.

ANNEX 3: *Proposed timetable*

Initiative	Consultation Response Deadline	Next Steps	
Carbon Price Support Mechanism[37]	10-Feb-07	Draft legislation for comment January 2011.	
Energy Market Reform (EMR)38	9-Mar-07	White Paper in late Spring 2011.	
Liquidity Review39		Ofgem will set out their proposals in Spring 2011.	
Impact of EMR on Renewable Obligation (RO)	See EMR above	See EMR above	
Banding Review (RO)		Announce banding scenario for consultation Summer 2011 and confirm Government response in Autumn 2011.	
Green Investment Bank		Design complete and published by May 2011.	

37_http://www.hm-treasury.gov.uk/d/consult_carbon_price_support_condoc.pdf
http://www.hm-treasury.gov.uk/d/consult_carbon_price_support_ia.pdf

38_http://www.hm-treasury.gov.uk/d/consult_carbon_price_support_ia.pdf
http://www.decc.gov.uk/assets/decc/Consultations/emr/1042-ia-electricity-market-reform.pdf
http://www.decc.gov.uk/assets/decc/Consultations/emr/1043-emr-analysis-policy-options.pdf

39_http://www.ofgem.gov.uk/Markets/WhlMkts/CompandEff/Documents1/Open%20letter_Liquidity%20in%20the%20GB%20power%20market_update%20and%20next%20steps.pdf

Proposed Method of Implementation	Expected Implementation Date
2011 Finance Bill	1 April 2013
Establish new powers in Primary Legislation from 2011 onwards	By 2013/14 secondary legislation in place, codes and licences in place and new scheme takes effect.
State Aid approvals to be checked.	Feed In Tariffs available from 2013.
See EMR above	Accreditation under RO to be available until 2017.
	RO to continue until 2037 but not open to new accreditation after 2017 and will be ‘vintaged’.
	New bands brought into force 1 April 2013 but April 2014 for offshore wind.
	September 2012

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