DECC

NOTE ON IMPACTS OF THE CFD FIT SUPPORT PACKAGE ON COSTS AND AVAILABILITY OF CAPITAL AND ON EXISTING DISCOUNTS IN POWER PURCHASE AGREEMENTS

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1. INTRODUCTION

This note considers the cost of capital impacts of different support packages as proposed by the Department for Energy and Climate Change (DECC) in its December 2010 consultation document and the associated December 2010 Redpoint Report. In particular, DECC has asked CEPA to comment upon:

- The potential reduction in the *costs of capital* for investors under a Premium FIT or CfD FIT from costs of capital under the existing Renewables Obligation (RO).
- The potential impact of the proposed support packages on the *availability of capital*.
- The potential impact of the proposed support packages on the *level of discounts* commonly seen in power purchase agreements (PPAs) between renewable generators and suppliers and borne by the former.

1.1. Approach

Our approach to assessing current contracting arrangements and approaches to determining cost of capital for different types of renewable projects under different support packages has been as follows:

- To understand the current approach to the pricing of debt and equity for different projects (both in terms of stage of – project cycle - development and technology type) under the RO by reviewing written submissions to DECC and through discussions with debt and equity providers, investment banks, project sponsors and electricity market participants.
- To understand the range of gearing targeted and achieved in current projects under the RO through discussions with debt providers and investment advisers.
- To review wider publicly available market evidence on target returns for investors in low carbon technologies /renewables in different markets.

Our review has focused more on hurdle rates/ required project returns, rather than a more traditional CAPM-based assessment of the cost of capital, given the lack of available data to support CAPM-based analysis for these types of investments and, perhaps more importantly, the way that in practice these projects are priced by providers of capital. As such, the objective has been to establish what costs of debt and equity and maximum gearing levels projects are consistent with achieving financial close, rather than what cost of capital necessarily *should* be given a the theoretical CAPM approach[1].

Our discussions have been with investors and advisers currently active in the low carbon and renewable investment arena, including but not limited to, members of the Low Carbon Finance Group (LCFG), as we consider that these stakeholders are key to any financing decisions in a world of supply constraints on that finance. It has been beyond the scope of this project to survey

[1] An approach employed in, say, regulatory price control decision making.

international investors who may or may not be familiar with the proposed support packages, and in any case we believe that current investors are best able to comment on the somewhat nuanced impacts of the different proposals.

We have also discussed with lenders and electricity market participants the current considerations that go in to determining the terms of PPAs and the extent to which these might change under the proposed new support regime.

We have not considered the impact of carbon pricing on costs and availability of capital as that is considered outside of the scope of this note. Similarly, there may be other impacts from other aspects of the EMR on costs and availability of capital which have not been considered – instead we have focused on the narrow impacts of a CfD FIT as compared to the current support regime.

1.2. Note structure

This note begins by providing a background and context to the new support regime before going on to consider the specific impacts of proposals contained in the December Consultation Document on cost of capital, availability of capital and current discounts contained within PPAs.

We also include two annexes – the first on the impact of higher gearing on the Weighted Average Cost of Capital (WACC)[2] and the second on current costs of capital for diversified energy and renewable companies.

In presenting this note, it is assumed that the reader is both familiar with the details of the Consultation Document as well as financial terminology.

[2] The WACC is the weighted average of the cost of debt and equity, weighted by the proportions of debt and equity in total capital employed; that is:
Post-tax WACC = g x COD + (1-g) x COE
where: g = debt / total financing (debt plus equity)
1-g = equity / total financing (debt plus equity)
COD = post-tax cost of debt
COE = post-tax cost of equity

2. CONTEXT

In this section we consider pertinent aspects of the context in which investment in low carbon investment is taking place in terms of the focus of such investment and the associated risks, developments in bank credit markets and the returns currently being looked for by lenders and investors.

2.1. Investment focus and risks

In order to meet agreed low carbon targets, the required investment in generation, in our view, is predominantly likely to take the form of large scale offshore wind and nuclear – which form the main focus for our report. These projects face considerable *construction* and *technology* risks, especially on the less-mature offshore wind industry, which will limit the class of investor available. For example, banks will not typically take on construction risk for offshore wind, although they will usually take a degree of market risk (primarily relating to the price at which energy is sold). This can be seen in deals being completed today for onshore wind, where banks are prepared to offer very high rates of gearing and relatively low rates of interest, despite some revenue risk.

Under the present system of support – the RO - construction and technology risks are perceived as greater than market risks and thus have more significant impact on cost of capital than market risk. That is not surprising: as we will discuss in greater detail in Section 3, hurdle rates will be greatest when a project is in the early stage of development, reducing at financial close (that is, pre-construction), reducing further post construction and further still once an operating history is available to investors.

2.2. Capital and pricing

New low-carbon investment is taking place following a severe contraction in the availability of credit, following the global financial crisis which began in 2008 and whose affects are still being felt.

Within this context, the quantum of capital required to meet Government targets is considerable at over £110bn[3]. Existing utility balance sheets are constrained, so much of the investment will need to be on a project finance basis and to draw in new investors, particularly for offshore wind (although we expect nuclear will be financed on balance sheet). Thus the supply curve for finance will necessarily be upward sloping.

Furthermore, the supply of credit – particularly longer term bank credit – in future may be more limited and costly. Basel III will increase internal funding costs for banks and LIBOR is expected to rise from its historically low levels of less than 1%. LIBOR has traditionally been used to price many bank-financed projects (that is, the pricing is LIBOR plus a fixed or stepped margin), although in practice many deals would see the use of swaps to fix the cost of borrowing for the project over the life of the loan e.g. an eight year swap for UK sterling is c3.5%, with the swap rate rather than current LIBOR rate thus driving the cost to the project.

[3] Update on the design of the Green Investment Bank. HMG, May 2011.

New types of investors will be required to deliver the low carbon infrastructure required, including institutional equity. Institutional investors are different from traditional energy investors as they are more likely to be pure financial investors – they do not have an operational interest in the investment or a strategic need to invest – instead they are looking for returns which are consistent with other opportunities available to them, typically of investment grade. They also require investments whose revenues and risks are readily understandable and explicable by intermediaries to the ultimate providers of the capital e.g. pension funds.

On the equity side, typically the approach to setting the project cost of capital will be to set a hurdle rate project internal rate of return (IRR), expressed in nominal post tax terms. An energy company might, for example, be faced with a range of investments in different sub-sectors/ services, and apply a different hurdle rate to each project. As such, the energy company's own cost of capital does not set the required rate of return for a particular project – it is the required project IRR that is key to an internal approval to proceed.

A Private Equity (PE) fund will also have both gross (before fees) and net (post fees and any investment losses) target IRRs. These IRRs will in large part be driven by the needs of the investors into the PE funds, who are typically pension funds. Pension funds in turn will have a range of asset classes available to them and minimum return rates or hurdle rates for each class. But those pension funds may not sub-divide each class into project specifics i.e. within investment into private equity, they may be comfortable that a certain proportion is for renewables, which would be allocated a return threshold, but it is unlikely that different types of projects within the renewable subsector would be allocated different hurdle rates. In other words, the pension fund will not be setting different return thresholds for wind under an RO/ green certificate versus under a Fixed FIT.

Similarly, most banks are concerned with the overall risk to the project and the level of sponsor commitment and are thus unlikely to have different pricing for different support regimes, per se.

3. IMPACT OF PROPOSED SUPPORT PACKAGES ON COST OF CAPITAL

In considering the impact of the proposed support package on cost of capital, we begin by looking at how cost of capital is currently determined and how it varies through the project cycle. We then consider the impact of the proposed CfD FIT on intermittent wind and provide a comparison of costs of capital for on-shore and offshore wind under the different support regimes. Finally, we consider the impact of both the CfD FIT and the Premium FIT on nuclear, which is currently outside of the RO.

3.1. Pricing through the project cycle

Our consultations on the cost of finance for larger scale new renewable projects under the current RO support regime have focused on larger scale offshore wind, as that is where many market participants are focused and are able to share views, and highlight the different return expectations across the project cycle, namely:

- *Project development stage risk returns*, which are likely to be 20% - 40%+ in nominal IRR terms to the point at which the project reaches financial close and is 'sold', or 15% - 17% + on a full project basis where the development risk is factored into the whole project ex ante.
- *Full life project returns*, which are of the order of 10% - 12%, including (as a cost) the development costs i.e. development costs are known/ development risk is excluded, although construction risk still needs to be considered and priced in.
- *Post construction returns* – that is project costs for projects which, post construction and once operating, are sold on to institutional investors by the developer of the project at an IRR (post tax WACC) of perhaps even as low as 8%.

For the purpose of the DECC analysis, it is the full life project returns that we are concerned with. Our consultations have produced a relatively consistent view of these returns at 10-12% post-tax nominal as a reasonable narrow range. Some projects may attract funding at below 10%, say at 9% - 10% where the construction risk is considered to be lower. Others may be higher, at say 12-15%, depending on the particular project characteristics, as well as assumptions on macro-economic factors, for instance, inflation. These are unlevered nominal post tax returns, from which the returns to debt and equity will be very different, as discussed below.

Costs of debt for such projects seem to be of the order of 6% to 7.5% at financial close, and assuming some construction risk remains in the project (although most likely with the sponsor not the debt provider). These costs are composed of a reference rate plus a margin. As noted above, the reference rate was traditionally LIBOR, but given that LIBOR is currently 'meaningless' the reference rate is more likely to be set by the swap rate (e.g. for a 15 year loan) and the relevant lender's Credit Default Swap (CDS) rate. This gives a reference rate of 3.5% - 4.0%, to which the margin will be added.

For example, for onshore wind under the RO, long term debt pricing is already relatively low at c6.5% in nominal terms, whilst for offshore wind pricing might only be 100bps or so higher (so c7.5%). Note that we understand that pricing for onshore wind is already close to the lender's 'floor' level, and that is for projects which have typically half of revenue exposed to market risk, with the other half derived from the support mechanism which is deemed largely stable (at least at the buyout price[4]), so clearly a move to a support regime with closer to 100% 'revenue certainty' will not have a direct one for one impact on pricing. It may, however, have an impact of gearing, which in turn can in practice impact the project WACC, and this is explored further below.

Note also that bank pricing for wind projects is typically structured in tranches, with prices increasing roughly every five years of tenor. This in part reflects a view of the future path of lending costs, and is in part an incentive for the project to re-finance at lower rates once an operating history has been demonstrated.

These bank rates do not therefore allow material scope for reduction with the removal of market risk. For onshore wind they are already at the lower end of feasible rates and for offshore wind the premium is largely driven by construction and technology risk, not market risk.

Acceptable levels of gearing will very much depend on project cash flows, the ability to meet key project finance ratios, such as debt capacity and debt service cover ratios and sponsor commitment. For offshore wind, gearing is likely to be of the order of 60-70%, whereas for onshore wind it gearing levels can exceed 80%.

Combining these components implies the costs of equity as illustrated in Table 3.1 below:

Table 3.1: WACC illustration for offshore wind – current regime

Component	Low	High
Cost of debt, pre-tax	7.5%	7.5%
Tax *	28.0%	28.0%
Cost of debt, post tax	5.4%	5.4%
Cost of equity, post-tax (derived)	17%	22%
Gearing	60.0%	60.0%
Post tax WACC, nominal	10.0%	12.0%

** note that 28% is the assumed corporation tax rate*

Clearly the implied cost of equity would differ if the assumptions on gearing or cost of debt were changed.

3.2. The CfD FIT for intermittent wind

We now consider the factors that will determine the impact of the CfD FIT on cost of capital for offshore wind.

[4] The inflation linked price that suppliers can pay to avoid having to purchase ROCs to meet their obligations under the RO.

The main concern expressed by investors and lenders as regards the CfD FIT, is the lack of visibility as to how it will operate in practice and specifically concerns regarding the new index and basis risks necessarily involved in the proposed approach[5]. The former can be defined as the risk that the index does not adequately capture the prices that it is supposed to; the latter that that the full strike price will not be realised because the generator will fail to realise the prices set out in the index.

The former is probably easier to overcome; for example, through an independent annual review of the index, its components and appropriateness, but the latter is a real issue as to whether intermittent wind can achieve the index in practice, especially given potential for wind cannibalisation and issues around differences between the index (say day ahead) and prices actually achieved (as actual prices will be set by in day, half-hour sales of volumes).

But if we *assume* that a contract/ support mechanism is designed to deal with these risks and to a significant extent the mechanism effectively behaves like a Fixed FIT, in that payments will be made on metered (flexible) output[6], coupled with an allowance for balancing risks, then investors are likely to deem more revenue as 'certain'. We also assume that the level of support will be similar to that under the RO for different technologies.

As we have noted above, the impact of increased revenue certainty is more likely to be felt through higher gearing rather than lower pricing of debt and equity. The question is then what is an appropriate assumption for an increase in gearing?

Gearing for onshore wind is already high at 75-80% under the RO. The natural limit for any project financing is probably 90%, as banks will want equity investors to have sufficient 'skin in the game' or cash at risk, but that will be for projects such as those under the private finance initiative (PFI) in which there is no volume risk in well established sectors. The 'natural limit' for a wind project might therefore be of the order of 85% gearing. Again it is important to note that in practice project debt service ratios will limit actual project gearing (rather than the notional maximum allowed in a term sheet).

If we assume that over time construction and technology risk for offshore wind reduce to the level currently accepted for onshore wind, then a similar impact might be achieved in offshore wind.

Thus, a CfD FIT which behaves like a Fixed FIT, over time is likely to have only a modest impact on project gearing levels and as such impact project WACCs by up to 1%. Note that this is not a very material impact given the assumed range for the WACC in the baseline. This is discussed in detail in Annex 1.

3.3. Impact of a Premium FIT on intermittent wind

Lenders and investors are reasonably comfortable with existing ROCs as there is a track record. Existing ROCs are also commonly perceived as being reasonably generous, although this is not

[5] Note that the approach illustrated in the Consultation Document may have exaggerated some of the risks over what they necessarily need to be with more specific design.

[6] This differs from a 'classic' CfD in which contracted volume are fixed, which exposes intermittent wind generators to considerable basis risk.

typically publicly stated by beneficiaries for obvious reasons. This is also most likely the main reason why many respondents to DECC appear to favour a PFIT – with familiarity and being comfortable with existing arrangements, and an assumption that the same level of support will continue, being more important factors than some of the other arguments advanced.

It is clear from this that investors are reasonably comfortable with a portion of revenue being exposed to wholesale market price risk. For example, two thirds of revenue is typically regarded as being fixed for offshore wind (revenue from the ROCs), with the remainder variable (revenue from the market).

Thus, a Premium FIT is assumed to operate largely as per a ROC and as such is assumed to have no impact on cost of capital relative to current support arrangements.

3.3.1. Comparing the impact of different support regimes on intermittent wind

We were also asked to provide a range of estimates for both on-shore and offshore wind under the different regimes so to be comparable with the modelling results previously provided by Redpoint.

In order to do so, we have modelled a five percentage point increase in gearing under a CfD FIT system for offshore wind and a maximum increase of 2.5% for onshore wind, as against the existing RO and possible Premium FIT regimes. In addition, there is an argument for offshore wind, that there may also be the potential for an increase in debt sizing as the sector expands, and the technology and its supporting services become more proven to lenders. However, the modelling has assumed no impact on the cost of equity or debt, even when offshore wind becomes a more mature technology, as hurdle rates are assumed to be set by investors and lenders on the basis of alternative opportunities. We have also assumed the same *level* of support is provided as under the current low carbon generation support packages in GB. The comparative results are presented in Table 3.2

Table 3.2: Impact of proposed support packages on WACC

Technology	RO / Premium FIT		CfD		Delta	
	(1)		(2)		(2) – (1)	
	Low	High	Low	High	Low	High
Onshore wind	8.4%	9.0%	8.4%	8.6%	0.0%	-0.4%
Offshore wind (emerging)	10.0%	12.0%	9.5%	11.2%	-0.6%	-0.8%
Offshore wind (established)	9.5%	10.4%	8.9%	9.6%	-0.6%	-0.8%

3.4. Impact on nuclear

The case of nuclear is rather different. To begin with, there is less market evidence and transparency on the range of cost of capital for nuclear without the CfD FIT. Investors are likely to be a small number of companies with large balance sheets willing to take development and construction risks and those investors will have different views on how returns are made, for instance through Engineering, Procurement and Construction (EPC) contracts, though operating and maintenance contracts, or through electricity sales. In many ways, that limited pool of investors will be able to dictate the cost of capital. It is thus only possible to estimate costs of capital in the broadest manner and our limited discussions suggest a broad range for the hurdle rate of 8-13% before the CfD FIT.

Potential investors are more likely to welcome a CfD FIT and there is thus potential for a positive impact on the required cost of capital. This is because it is much easier for a base-load plant such as nuclear to achieve an average wholesale price and not to expose investors to basis risk. Furthermore, a far higher proportion of the nuclear generators revenue will depend on market risk without a floor price for carbon and a CfD.

On this basis, CEPA supports the Redpoint impact numbers which give a one percent reduction for PFIT and a two percent reduction under a CfD.

4. IMPROVING AVAILABILITY OF CAPITAL RELATIVE TO EXISTING ROCS

4.1. Introduction

In addition to potential impacts on costs of capital, the CfD FIT may also have an impact on the availability of capital. We begin by considering sources of traditional and new capital and in particular the requirements of the latter as regards investment in renewable generation.

4.2. Sources of capital and the project cycle

There are two main sources of capital for investments such as offshore wind – existing and new. Existing providers of finance for project financings are typically developers and existing utilities on the equity side and banks providing debt. As discussed above, the balance sheets of the existing utilities are unlikely to be large enough to finance the required level of investments, hence the need for project financing.

The potential new sources of capital – notwithstanding the limited involvement that they have at the moment - are institutional investors such as pension funds and life assurance companies, who invest in both equity and fixed income products. These latter products may take several forms including project bonds and different forms of bundled investments, including corporate bonds, collateralised bond obligations and other forms of asset-backed securities. It should be noted that at the moment there are few, if any, examples of these instruments being employed in offshore wind, but they are the main way in which (debt) capital markets are accessed. It is important to note that debt will be likely to account for between two thirds and perhaps three quarters of total financing requirements depending upon which part of the project cycle is being considered – attracting institutional debt is therefore arguably more important than attracting institutional equity.

These different entities might be expected to invest at different stages in the project cycle. Whilst new developers providing equity may enter the market, pre-financial close, it might be expected that it will be the traditional players who continue to be active, given their ability to deal with the different project development (specifically planning), technology and construction risks. Very few institutional investors have the appetite to invest at these stages because of the risks, although it might be noted that Dong was recently able to bring in a pension fund to an offshore wind investment at financial close, it did so by protecting it against construction risk.

4.3. Requirements for increasing availability

Improving the availability of capital will depend upon whether or not the new arrangements are seen to improve the revenue certainty of the investment, whether this is for existing or new investors. As regards the former, this is likely to be more an issue of not reducing investor confidence, so as they remain interested in such investments at both the development and construction phases. As regards the latter, it is likely to be more of a case of meeting the specific requirements of institutional investors. For fixed income products, at a minimum, this will require an appropriate investment rating provided by credit ratings agency. Indeed, if this could be achieved then it would open the door to many investors who would be willing to invest (only) once an investment grade rating is in place. Thus, there will be a necessity of convincing the ratings agencies of the merits of such products; however, unlike less specialist investment professionals, the agencies should be able to understand the risks involved, although typically – "the simpler, the better" is still likely to hold to a degree.

The main benefit of attracting institutional investors to the sector, particularly for fixed income products, will be that it will allow the debt capital provided by project finance lenders to be recycled into new investments. Note that any reduction in project cost of capital arising through this – say as a result of greater leverage or lower debt pricing – will flow to the equity (sponsor) not the consumer, in the absence of any claw-back arrangements.

As for the cost of capital, investor interest will depend on how the proposed CfD FIT works as to whether it will attract more interest than the current ROC scheme. If it does take away the price volatility from the revenues of the project that should make the project more attractive to the investors that are looking for lower risk investments - particularly in the post construction period.

4.4. Conclusions

If the CfD FIT is seen as simply introducing a different type of revenue volatility, (that is, the difference between the chosen index and the price actually obtained by each wind farm compared to the current electricity price fluctuations), and may even reduce upside, there would be limited scope to significantly increase the volume of investment particularly from those parties looking for more stable areas to invest. This is a new sort of volatility that may be difficult to estimate and could significantly influence the revenues, whilst the ROC scheme provides around two thirds of the revenues in a fixed stable way, with investors able to take a view on where power prices will trend over the next 20 years. Initially, therefore, the CfD FIT could slow down investment whilst the market considers how it is likely to work in practice.

Arguably, though, whilst investors and lenders seem comfortable with a portion of revenue risk under the ROCs in the short term, in the longer term the impact of so-called wind cannibalisation would be potentially more profound under the ROCs than under the CfD FIT. Thus, post construction, this degree of price certainty – as long as the design is seen to mitigate and / or minimise basis risk to acceptable levels, could be helpful in enabling renewables investments such as offshore wind to secure an investment grade credit rating and thus enabling access to a greater range of sources of, particularly debt, capital.

Ultimately, the more such investments look like utility investments the more likely they are to secure the required ratings and to attract capital. The closer the CfD FIT looks to a Fixed FIT, the better in this respect. However, the rejected RAB-based approach would have been optimal in this respect and may also have lowered cost of capital to a greater degree.

5. IMPACT ON PPA 'DISCOUNTS'

5.1. Overview

A PPA serves two main purposes: (i) it underwrites revenue, which allows the sponsor to bring in bank finance; and (ii) serves to sell physical power.

In general, PPAs for renewables will contain a discount on the revenue stream to reflect the risks being taken by (and perhaps bargaining power of) the offtaker, in this case one of the Big 6 suppliers. The risks to be considered, in terms of potentially being removed are:

- Imbalance risk, both volume and price, arising from differences between the reference price, for example, a day-ahead index, and actual sales value.
- Longer term price risk.
- 'Cannibalisation risk'.

It is the overall level of discount in PPAs that matters to the generator, and the practicalities of how these discounts are applied matters less, for example, whether the discount is applied to the power element or the 'green' element. We have heard different stories as to the range of discounts applied, from up 10% on the power only (at least in the initial PPA period, say the first five years), to 20%-35% on the power together with 5-20% on the green revenue element, although it may well be that where the higher discounts apply the PPA also includes a top-up element such that a minimum payment (£/MWhr) or floor is achieved and thus the project becomes bankable. This latter form of top-up may be becoming less common and being replaced with a collar mechanism, such that the offtaker sees more of the upside, as well as continuing to take the downside risk. It also seems that historically standard levels of discount are being applied to larger projects, whereas it might be expected that the percentage to decrease with project size (as some costs, such as administration costs around balancing, will be fixed for the off-taker, and therefore do not increase in absolute terms in line with project size).

The question is whether these costs might be reduced under arrangements in which generators are better able to avoid selling to a Big 6 supplier through a PPA, resulting in a lower support requirement. A key likely difference between the current RO and the CfD FIT arrangements is that under the former a renewable generator receives both its subsidy (ROC) and wholesale price revenues through the supplier. However, in the case of the latter, the CfD FIT revenues would be received from a central agency and wholesale price revenues could be received directly from the market, rather than through a PPA. In theory, this would suggest that generator would be in a stronger position, in that it would be less reliant on the Big 6 suppliers. However, whether these benefits could be realised in practice depends upon two questions being answered favourably.

First, whether generators will be able to borrow without a PPA being in place, or without some other means of ensuring that physical output is purchased. If this were to be possible it would seem that investors and more conservative lenders would need to be comfortable that physical power could be sold, thus triggering the payment of the top up CfD FIT. This might be achieved through the creation of a central or purchaser of last resort, or a very much higher degree of market liquidity than is currently the case. Note that the realisation of such prerequisites would involve wider market reforms, involving other aspects of the EMR as well as wider market reform on liquidity, over and above the introduction of the CfD FIT per se.

Second, as there will still be a need for balancing within the system, the issue is whether or not the current balancing charges are either a true reflection of their true costs and /or whether this service might be provided more cheaply than at present by another entity, or by providing intermittent generators with an allowance to self balance - with which they would pay any imbalance charges directly to the System Operator (SO). Charges would not be cost reflective if the current role of the Big 6 meant that they had an overly strong bargaining position for them viz a viz the generators, such that charges were excessive (however, this point is controversial and has not been proven). It may be, however, that another entity providing such a service might be able to achieve balancing at a lower cost than the existing Big 6; again this might involve a central entity or a larger role for the existing SO.

Thus, whilst in theory the CfD FIT should create more competition which would force a reflection of true balancing costs – whatever they are – it is difficult to see how this would be realised if renewable generators still required PPAs from the Big 6; that is, they were not bankable on a merchant basis.

In the sub-sections below we consider the specific charges listed above.

5.2. Impact on balancing costs of proposed changes

Under current arrangements, renewable wind generators typically pay the suppliers who purchase their electricity output a fee for balancing services. Although such generators already have the notional option of selling physical power directly into the market, a combination of limited liquidity and balancing costs that would be disproportionately high for a single generator (that is one without the ability to reduce balancing costs through a portfolio effect), means that in practice they nearly always sign a PPA.

Whilst the proposed CfD FIT can behave like a Fixed FIT on the financial side, there is still a need to sell physical power and there will still be balancing costs within the system – hence it is not surprising that there are PPAs in use in many regimes with FITs. Furthermore, lenders have suggested to us that it is likely that wind projects without PPAs (in the absence of say a state-backed purchaser of the power) will not be bankable.

There seems to be some concurrence of view that imbalance costs for a generator might, today, be of the order of 10%, reflecting current charges by the SO within the balancing market. Generators are therefore willing to see their power price discounted in return for the removal of this risk. However, in making these charges, suppliers are not passing on any aggregation / self-balancing benefits that they achieve through portfolio effects, to the generators (although we did receive a comment that these may not be as great as might be first thought because of differing generation time profiles between renewables and the vertically integrated suppliers' own gas or other generation). Importantly, though, we have heard that banks are not willing to take imbalance risk; that is, they would prefer to see the generator's revenue stream insulated from this risk.

As noted above, the current market structure means that all power is sold through a limited number of suppliers whose charges for balancing would appear to be higher than those quoted within either the Spanish market or Nordpool. It has been argued that if generators are only willing and able to pay such charges because of the generosity of the ROCs, if this was lower, prices would be driven lower. However, presumably to compare one arrangement with another on a like for like basis, would require that the starting level of support under the CfD FIT would be set so as to provide an equivalent revenue as per the current ROCs. As such balancing charges might be expected to remain the same as now because the level of support would enable the existing arrangements to continue, in which the true costs were masked.

Alternatives to these arrangements could include the provision of balancing services by another party which would pass them through at cost. These costs might be lower where the provider of the service was able to achieve greater portfolio benefits than those of a Big 6, improving both technical and allocative efficiencies. This could require the creation of a new entity or extending the role of an existing one.

Finally, if generators were provided with a realistic allowance with which to absorb balancing charges, this could allow them to by-pass the Big 6 potentially reducing the amount paid in balancing charges and reducing the amount of support required to address them. This could be realised through a trustee who exacts a levy on end consumers for balancing costs, with those charges periodically reviewed and reset.

At a minimum, the availability of alternative means of dealing with balancing costs; that is, the creation of competitive alternative routes other than through the existing PPAs, will help tease out what true balancing costs might be. For instance, this may encourage the existing suppliers of services to price more competitively, if they are indeed currently over-charging, or they may just cease to offer the service all together. However, we would suggest that all of these measures are again related to other structural and regulatory reforms, rather than the provision of a CfD FIT per se; even the provision of the proposed balancing allowance could arguably be provided in isolation from the main support mechanism. As such, it is not clear that the CfD FIT approach will reduce the amount of support required to cover balancing costs in the absence of other reforms.

5.3. Impact on pricing

We understand that very few PPAs contain a longer term fixed price, for the simple reason that the off-taker cannot hedge/ pass off that risk – there are no say five year plus products in the market whereas the PPA might be for 15 years. It would be possible for PPAs to include fixed price elements for say two years plus, but these would be heavily discounted at say 20% plus, so would be unattractive to the generator. Furthermore, and crucially, banks today already regard a portion of a renewable generator's revenue as fixed, for example, two thirds for offshore wind. This alone makes the project bankable so there is then no need for the generator to take a steep discount on the power element of the revenue.

However, arguably the need for a generator to pay for a floor or minimum price through a discount in the PPA would seem to be removed under the CfD FIT (that is, passed through to the customer), assuming that basis risk is minimised through a combination of appropriate design and arguably the allowance set out above.

5.4. Impact on 'Cannibalisation'

Cannibalisation risk is not often explicitly dealt with in a PPA. But if it is understood to mean an increase in risk that the power price on the day might be driven down by high volumes of wind, then this seems to be being dealt with by further discounts in PPAs that kick in after five years. So the power price discount could increase by say a further 10% after five years. Or it could be stepped to be 20%, 25%, 30% over each of the five years with a lower, say 5-10% applied to the green element. The CfD mechanism arguably could deal with this, again, as long as the reference price was a good reflection of the prices achieved by generators and / or they were in a position to realise the index price (that is, limited basis risk). But if the increased wind volume increases the basis risk then clearly there will be higher imbalance costs/ discounts. But on balance it seems as though the 'cannibalisation risk' premium might be reduced through a CfD that is close to a Fixed FIT.

5.5. Conclusions

Thus, there would appear to be a case that, if designed appropriately, relative to the ROCs, the CfD FIT could reduce the need for the scale of discounts under PPAs associated with providing a price floor and to deal with cannibalisation (assuming these charges are a function of true cost rather than market power). At a minimum, the justification for such charges is reduced. These may therefore reduce the amount of subsidy required.

However, on balancing costs, it is less clear that the CfD FIT alone could reduce these costs as they would still be in the system.

The achievement of further technical (lower cost) and allocative (competitive) efficiencies, where available, would arguably need other reforms that would enable generators to by-pass the existing suppliers. Splitting a balancing allowance out from total support costs might help, especially where a PPA was not required for the generator to raise finance – specifically where there might be a high degree of liquidity which would create certainty to the generator and its lenders that there was a market for physical sales (although this may be a considerable 'ask' at the moment). However, arguments presented elsewhere set out the benefits that could arise from, for instance, a Central Market Agent or indeed a Central Renewables Purchaser in achieving reductions in balancing costs and providing an alternative route to market.

ANNEX 1: IMPACT OF PROPOSED SUPPORT PACKAGES ON WACC - WIND

Overview

In this annex we model the impact on the cost of capital for onshore and offshore wind under different proposed support packages. Our baseline assumptions are as follows:

Table A1: Baseline WACC illustration for onshore and offshore wind – current regime

Component	Offshore wind		Onshore wind	
	Low	High	Low	High
Cost of debt, pre-tax	7.5%	7.5%	6.5%	6.5%
Tax[7]	28.0%	28.0%	28.0%	28.0%
Cost of debt, post tax	5.4%	5.4%	4.7%	4.7%
Cost of equity, post-tax	17%	22%	17%	22%
Gearing	60.0%	60.0%	70.0%	75.0%
Post tax WACC, nominal	10.0%	12.0%	8.4%	9.0%

Note that returns for development capital are much higher than the equity returns illustrated above, especially where there is higher development risk e.g. offshore wind. The returns above reflect whole project life returns.

It is unlikely the renewable support package will impact on the cost of debt or equity, as hurdle rates are assumed to be set by investors and lenders on the basis of alternative opportunities. We assume no impact in our modelling analysis.

We also note the following:

- For debt sizing, a key issue for lenders is what part of the revenue stream is considered as variable and which part is fixed.
- Under the RO the revenue streams (according to the Low Carbon Finance Group response) can be split into stable, and more volatile, variable revenues.[8]
- A 'stable' debt service cover ratio is targeted for stable revenues. For variable revenues, a higher (more conservative) debt cover ratio will be applied.

The benefits of a CfD FIT (compared to a Premium FIT or the RO) for gearing therefore depend on the ability of a CfD payment to move projected revenues from a "variable" (conservative) to 'stable' (more aggressive) debt cover ratio, and so increase project debt capacity.

[7] Note that we have used the historic tax rate of 28%. As this tax rate reduces, it would be expected to marginally increase the post tax hurdle rates.

[8] The ROC *buy-out* price and a electricity price floor are considered stable revenue. The re-cycled ROC value and revenues from an electricity price above the floor are considered variable.

Impact of proposed support packages – onshore wind

Onshore wind is a proven technology, with well understood technology and construction risks. Gearing levels achieved under the RO have been in the range 75-80% and 80-85% for European countries with FIT systems:

Table A2: Onshore support systems and gearing

Country	Support system	Gearing
UK onshore wind	RO (Green Certificate)	75-80%
RoI onshore wind	FIT	80-85%
Spain onshore wind	Premium FIT with cap & floor	80-85%
France onshore wind	FIT	80-85%
Germany onshore wind	FIT	80-85%

Source: Low Carbon Finance Group

Under the RO, onshore wind has in the past achieved gearing levels of 75% or higher. Since the financial crisis, however, we understand 75% gearing may now be more typical for most projects. Further increases in gearing are likely to be capped. Lenders require project sponsors to maintain "skin in the game" and gearing levels much higher than 80% have typically only been observed for quasi-government backed infrastructure projects, such as the PFI. Assuming a CfD FIT could be designed to provide greater price certainty to onshore wind, we assume the CfD payment system may (at maximum) increase gearing by up to 2.5 percentage points. Note further that given the gearing for onshore wind is already high, we think that any gearing benefit from a CfD that behaves like a Fixed FIT will be more muted, at say an additional 2.5% at the top end.

Table A3 shows the impact on WACC of a 2.5% percentage point increase in gearing under a CfD FIT compared to the current RO support system and a Premium FIT.

The delta range on emerging and established wind is the same as we believe the relative gearing effect from more 'certain' revenue is the same, although please note that the WACC is higher for emerging wind than for established wind, as you would expect (see Table A7).

Table A3: WACC illustration for onshore wind

Component	Current regime		Premium FIT		CfD FIT	
	Low	High	Low	High	Low	High
Cost of debt, pre-tax	6.5%	6.5%	6.5%	6.5%	6.5%	6.5%
Tax	28.0%	28.0%	28.0%	28.0%	28.0%	28.0%
Cost of debt, post tax	4.7%	4.7%	4.7%	4.7%	4.7%	4.7%
Cost of equity, post-tax	17.0%	22.0%	17.0%	22.0%	17.0%	22.0%
Gearing	**70.0%**	**75.0%**	**70.0%**	**75.0%**	**70.0%**	**77.5%**
Post tax WACC, nominal	8.4%	9.0%	8.4%	9.0%	8.4%	8.6%
Mid-point (low / high)	**8.7%**		**8.7%**		**8.5%**	

Impact of proposed support packages – offshore wind

In comparison, offshore wind currently faces considerable construction, technology and O&M risks. Gearing levels achieved under the RO have been in the range 60-70% while countries such as Germany with FIT systems have achieved gearing in the range 65-75%:

Table A4: Onshore support systems and gearing

Country	Support system	Gearing
UK offshore wind	RO (Green Certificate)	60-70%
Germany offshore wind	FIT	65-75%

Source: Low Carbon Finance Group

Assuming a CfD FIT could be designed to provide greater price certainty, its main impact on the cost of capital for offshore wind would also be through increased gearing – with possible increase in debt sizing because of reduced revenue volatility. We assume that this may increase gearing by approximately five percentage points, given the lower starting point.

Table A5 shows the impact on WACC of a five percentage point increase in gearing under a CfD FIT compared to the current RO support system and a Premium FIT.

Table A5: WACC illustration for offshore wind (emerging technology)

Component	Current			Premium FIT		CfD FIT	
	Low	High		Low	High	Low	High
Cost of debt, pre-tax	7.5%	7.5%		7.5%	7.5%	7.5%	7.5%
Tax	28.0%	28.0%		28.0%	28.0%	28.0%	28.0%
Cost of debt, post tax	5.4%	5.4%		5.4%	5.4%	5.4%	5.4%
Cost of equity, post-tax	17.0%	22.0%		17.0%	22.0%	17.0%	22.0%
Gearing	**60.0%**	**60.0%**		**60.0%**	**60.0%**	65.0%	65.0%
Post tax WACC, nominal	10.0%	12.0%		10.0%	12.0%	9.5%	11.2%
Mid-point (low / high)	**11.0%**			**11.0%**		**10.3%**	

Incentive mechanisms, like a CfD FIT, will not address the construction and technology challenges with offshore wind. But as the sector expands, and the technology and its supporting services become more proven to lenders, acceptable levels of gearing for projects (driven by the application of less conservative debt cover ratios) may increase. Table A5 shows the impact on WACC of a 5 percentage point increase in gearing under a CfD FIT system, where offshore wind is considered a more established technology by lenders.

Table A6: WACC illustration for offshore wind (established technology)

Component	Current			Premium FIT		CfD FIT	
	Low	High		Low	High	Low	High
Cost of debt, pre-tax	7.5%	7.5%		7.5%	7.5%	7.5%	7.5%
Tax	28.0%	28.0%		28.0%	28.0%	28.0%	28.0%
Cost of debt, post tax	5.4%	5.4%		5.4%	5.4%	5.4%	5.4%
Cost of equity, post-tax	17.0%	22.0%		17.0%	22.0%	17.0%	22.0%
Gearing	**65.0%**	**70.0%**		**65.0%**	**70.0%**	**70.0%**	**75.0%**
Post tax WACC, nominal	9.5%	10.4%		9.5%	10.4%	8.9%	9.6%
Mid-point (low / high)	**9.9%**			**9.9%**		**9.2%**	

Summary

Table A7 summarises the analysis presented in this annex. In summary, we have modelled a 5 percentage point increase in gearing under a CfD FIT system for offshore wind and a maximum increase of 2.5% for onshore wind. For offshore wind, there may also be an increase in debt sizing as the sector expands, and the technology and its supporting services become more proven to lenders. The modelling has assumed no impact on the cost of equity or debt, even when offshore wind becomes a more mature technology, as hurdle rates are assumed to be set by investors and lenders on the basis of alternative opportunities. It also assumes the same *level* of support is provided as under the current low carbon generation support packages in GB.

Table A7: Impact of proposed support packages on WACC

Technology	RO / Premium FIT		CfD		Delta	
	(1)		(2)		(2) – (1)	
	Low	High	Low	High	Low	High
Onshore wind	8.4%	9.0%	8.4%	8.6%	0.0%	-0.4%
Offshore wind (emerging)	10.0%	12.0%	9.5%	11.2%	-0.6%	-0.8%
Offshore wind (established)	9.5%	10.4%	8.9%	9.6%	-0.6%	-0.8%

ANNEX 2: ANALYST VIEWS

To provide further context to the views presented in the body of the report we report below a selection of views from analysts on the WACC of generation businesses active in the renewables sector. Many of these businesses have mature portfolios, and as such provide a bottom end to WACC estimates for newer technologies/ higher risk sub-sectors, such as offshore wind.

5.6. Acciona

Acciona assets are predominantly focussed in the onshore Spanish wind market with a limited construction portfolio.

Analysts estimates of Acciona WACC

Analyst	WACC estimate
Barclays Capital Jan 2011	14.9%*
Citigroup May 2009	6.2%
Exane Paribas Dec 2010	8.7%
HSBC Mar 2011	7.5%
Range**	6.2% - 8.7%
Average	7.5%

* Pre-tax; **Excluding pre-tax estimates

5.7. EDF EN

EDF EN is the renewable arm of EDF which has a 50.0% stake in the company. Whilst it is expanding its portfolio, 89.0% of installed capacity remains onshore wind.

Analysts estimates of EDF EN WACC

Analyst	WACC estimate
Barclays Capital Jan 2011	10.2%*
Exane Paribas Dec 2010	7.6%
HSBC Mar 2011	7.5%
Nomura May 2009	7.5%
Range	7.5% - 7.6%
Average	7.5%

* Pre-tax; **Excluding pre-tax estimates

5.8. EDP Renovaveis

EDP Renováveis is the part of the Energias de Portugal group which operates in the field of renewable energy. EDP Renováveis is the 3rd biggest renewables company in the world and the second-largest generator of wind energy globally.

Analysts estimates of EDP Renovaveis WACC

Analyst	WACC estimate
Barclays Capital Jan 2011	14.0%*
Exane Paribas Dec 2010	7.3%
HSBC Mar 2011	8.5%
Nomura Mar 2011	8.0%
Range	7.3% - 8.5%
Average	7.9%

* Pre-tax; **Excluding pre-tax estimates