When setting the support level, it is important to consider the actual revenues realised by generators when setting the support levels. If not all of the potential value is realised by generators (in particular independent generators) then the level of support should reflect this. It is, however, perverse to provide higher than necessary levels of support just to compensate for the value extracted by suppliers. It is far more cost-efficient to ensure the market arrangements are competitive and liquid to prevent suppliers extracting value in the first place.

- **Are there other models Government should consider?**

The Government should continue to set support levels by independent analysis, as happens under the RO. There is currently potential for development hiatus for long lead time technologies such as biomass and offshore wind. Much of this potential could be avoided if projects qualified for certain support levels at earlier stages in the development process. It would be possible for the Government to set out in a contract the level of support a project would be entitled to once completed, and set out the date when the project should be completed. The time given for construction could be differentiated by technology and project size.

- **Should prices be set for individual projects or for technologies?**

Support levels should be set for technologies, with perhaps bands within certain technologies to reflect certain characteristics, such as distance from shore for offshore wind projects. It is difficult to see how project specific support levels could be competitive or workable.

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

We do not consider there to be sufficient competition between potential developers or sites to run effective auctions. The new nuclear and offshore sites have already been determined and the consortia involved have set out their plans. The pace of nuclear and offshore development is likely to mean there will not be more than one or two sites competing in an auction at any one time and these may be controlled by the same entities. It is therefore impossible to secure a competitive outcome in such a situation. A developer of such large-scale projects would not take the development risk if it was not confident that the project would be eligible for support at completion.

- **Could an auction contribute to preventing the feed-in tariff policy from incentivising an unsustainable level of deployment of any one particular technology? Are there other ways to mitigate against this risk?**

Auctions will fundamentally undermine the delivery of low carbon projects. The biggest risk will be that levels of deployment are unsustainably low.

If the Government considers that unsustainably high levels of deployment would necessitate intervention, it must set out exactly what it would consider to be unsustainably high levels of deployment. It is better to control an unsustainably high deployment of any one particular technology through the adjustment of the level of support. Any adjustment must, however, take into account expenditure on project development that has already occurred on projects which are not yet operational. The government would need to provide sufficient notice periods to prevent this from occurring, especially for nuclear and offshore wind.

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

We consider that substantial reforms to the wholesale electricity market are needed in order for the proposed reforms to work effectively. To prevent vertically integrated utilities from exerting unreasonable control on the market it is necessary to reduce the market barriers which currently exist. The lack of a liquid wholesale market is key to this. It is vital that independent generators are able to secure finance without requiring a PPA with a VIU. At present suppliers retain 10-20% of the total value of a PPA; this is far higher than the costs incurred. In Sweden, which operates as part of the Nordpool electricity market, PPAs[1] incur a cost of €2/MWh, which largely reflects the physical cost of operating a trading desk and balancing costs. The equivalent in the GB market is three or four times that amount. There is a significant risk that if the obligation on suppliers to contract for renewable electricity is removed, that the discounts within PPAs will increase substantially. This will lead to considerable unnecessary cost to the consumer.

In order for PPAs to be avoided, it is necessary for the market to be liquid. At present the majority of power traded on exchanges is for balancing purposes. It is necessary for all power in the market to be traded on an open and transparent exchange. Generators should have a viable and direct access to the market. Many independent generators are currently dependent on PPAs with suppliers, which creates a large amount of market power for suppliers.

There are a number of wider institutional arrangements required for the efficient delivery of the EMR proposals. We do not consider that Ofgem is likely to come forward with sufficiently robust proposals over market liquidity. Ofgem has effectively been tasked with evaluating the operation of the market that it created. We believe that DECC should take on responsibility for the liquidity review to ensure that it meets the needs of the EMR objectives and can be delivered in the timescales needed for the EMR.

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

To minimise market distortion it is necessary to have a liquid and competitive market. There is an implication in the consultation that low carbon generation could distort the market. Most low carbon generation is not readily able to respond to market price signals. It is possible for the system operator to constrain low carbon generation in periods of high wind or low demand. It is likely that a well functioning constraints mechanism will be cheaper overall than seeking to resolve such issues in the support mechanism. A CfD which incorporated an element of 'beating the market' is likely to be unnecessarily complex and create huge potential for unintended consequences.

It is important for the impact of the carbon price support on the SEM and interconnector flows to be fully considered. The CPS is likely to cause substantial distortions to the market. Evidence on the potential impact is provided in our response to question 6.

There is a significant risk of existing PPAs being reviewed, especially as a result of the Carbon Price Support and proposed changes to the Balancing Mechanism which will make cashout prices sharper. These factors, combined with the removal of the obligation on suppliers, there is a risk that suppliers will attempt to open up existing PPAs under change of law clauses.

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

[1] PPAs are secured to avoid generators having to trade in the market themselves, they are typically for five years and the counterparty is a market trader rather than a VIU.

It is far more important to get the reforms right than introduce them quickly.

There is, however, a considerable risk of delays whilst the reforms are being implemented. We recognise there is a very difficult trade off between investors' need for certainty as soon as possible and the need to ensure sufficient time is taken to ensure the measures introduced are workable. Given the long-term implications of introducing a system which was not properly thought out, it is vital that the development of the mechanisms is not rushed. To provide confidence to investors over the intervening period, it is important that the Government acts in a manner that demonstrates its determination to improve the environment for investment in renewables.

It is imperative to enable a smooth and steady increase in renewables investment. Steady roll out will give the supply chain the confidence to establish itself in the UK. Stop-start investment cycles do not create stable conditions for investment in projects or supply chain infrastructure.

The proposed reforms are likely to make it difficult to secure competitive prices from VIUs until there is more certainty over the future structure of the market and support mechanism. We welcome the advancement of the timetable for the ROC banding review as it should provide more clarity to the market about the level of support available for projects currently reaching financial close. There is considerable concern at present that the reforms are being rushed and that insufficient consideration has been given to vital details of the packages. The current structure of the wholesale electricity market and the implications of removing the obligation on suppliers given the structure is a major omission to date.

We consider that there is a substantial risk of a development hiatus from the proposals. Moving eligibility for a particular level of support from energisation to financial close could help reduce the potential for development hiatus that occurs during the revision of support levels.

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

The Government needs to make an unequivocal statement that new projects will not be forced into the new support system before 2017. This will provide greater certainty to projects currently under development.

The proposal to determine the level of support to which a project is eligible at an earlier stage in the development process is welcome. This will give far greater certainty at the point of investment.

We believe that a key oversight to date has been the impact of the changes on renewable generators' position in the market. The focus of grandfathering has been on the relative value of a ROC. Almost no consideration has been given to the likely value of a generators' power following the proposed changes. The impact of the removal of the obligation on suppliers is the main reason for generators' position being undermined.

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

- **All new renewable electricity capacity accrediting before 1 April 2017 accredits**

under the RO;

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

As outlined above, we believe the Government should categorically state that no new projects will be forced onto the new support mechanism before 2017. RO support must remain a realistic, financeable and credible option for new projects until 2017.

Projects with longer development and construction times may need to have the option to be supported under the RO extended beyond 2017, as investment decisions are likely to need to be taken as early as 2013 for projects which do not become operational until after April 2017. Given the likelihood of slippage in the EMR implementation timetable, it is necessary to ensure that investment decisions which need to be taken around 2013/14 have sufficient clarity to progress.

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

• Carry out scheduled banding reviews (either separately or as part of the tariff setting for the new scheme)? How frequently should these be carried out?

• Carry out an "early review" if evidence is provided of significant change in costs or other criteria as in legislation?

• Should we move them out of the "vintaged" RO and into the new scheme, removing the potential need for scheduled banding reviews under the RO?

We consider that the level of support available post-implementation of the EMR should take account of the relative and avoided costs of generation. For biomass co-firing the relative cost of biomass and coal under the carbon price support should be considered. It is likely that the level of support needed for biomass will decline as coal becomes relatively more expensive under the carbon price support.

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

• Continue using both target and headroom

• Use Calculation B (Headroom) only from 2017

• Fix the price of a ROC for existing and new generation

We consider that calculation B should be used from 2017 onwards. This will maintain an obligation on suppliers, which will help protect existing generators' position in the market.

Annex A

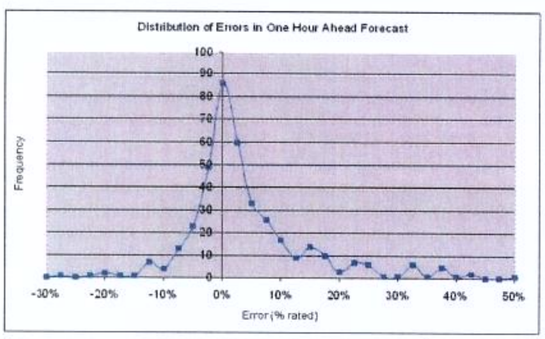
Basis Risk

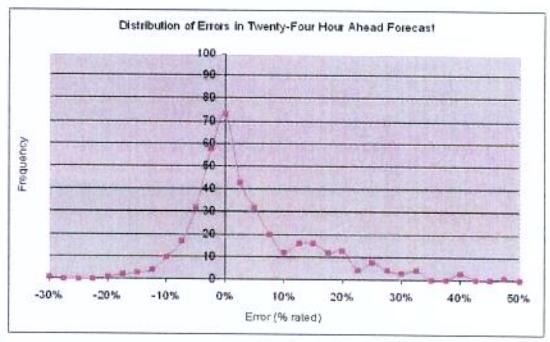
We are very definite in our opinion that the CfD, if implemented, needs to reference half-hourly prices to avoid the creation of 'basis risk'. This annex details our understanding of basis risk and some of issues that could give rise to it.

Basis Risk occurs when;

- There is a timing difference between the reference point at which the CfD is struck and the reference point of a PPA. (ie if the CfD is struck on a month-ahead price and the PPA is referenced to a day-ahead price). The potential for price volatility between the two points will undermine price stability that the generator received and one of the key perceived benefits of the CfD.

- There is volume risk at the point of striking the CfD and the point of delivery (assuming the CfD and PPA are referenced to the same point). We would expect the PPA provider to fix their position in the market at the same reference point as the CfD according to their best forecast of output. If the low carbon generator is non-dispatchable, then the level of confidence in that forecast will depend on the accuracy of the forecasts. The accuracy of the forecasts improves significantly as we move towards gate closure. The probability as well as the scale of error declines significantly as gate closure approaches. The figures below show the error distribution of generation forecasts one hour ahead of generation and 24 hours ahead of generation. The one hour ahead is significantly tighter and more centred around 0%.





As we move closer to gate closure the risk of forecast errors declines and this will reduce the risk exposure that traders will pass on to generators through their margin. Furthermore, as we move closure to gate closure the benefits of aggregation increase as there is less likelihood that a low or high forecast error will be correlated across the country.

- If there is a significant volume of low carbon generation on the system, a correlation between the output of non-dispatchable generators can have a defined price impact. This will amplify the volume risk as the low volume periods are likely to correlate with high prices and high volume periods with low prices. If there is significant volume uncertainty (ie the CfD/PPA price references the week or month ahead) then the volume risk will be amplified by the price impact.

When pricing the PPA, a trader will need to quantify the additional impact of this risk over the lifetime of the PPA (which will match the 20 year CfD term). Traders will inevitably be cautious and are likely to factor in more risk than might prove to be the case. The realisation of such risks will depend largely on the effectiveness of Government policy including those directly impacting intermittent deployment and indirect regulations such as the arrangement of the balancing mechanism.

This volume risk can either be priced into the PPA or will be fed through directly into the CfD.

- If volume risk is fed into the CfD by using a half-hour CfD strike price, then the volume risk is passed onto the consumer through the CfD. However, this allows the consumer to fully recover any benefit if either the volume risk is not as high as anticipated, or if other market developments such as storage, improved interconnection, demand side management and improved forecasting reduce volume risk.
- If volume is priced into a PPA then it is likely that the PPA providers will be overly cautious when factoring in these risks over the 20 year period of the PPA. As a result the overall support requirement will be higher and in addition any benefits that arise from market developments, interconnection etc, would be captured directly by the PPA provider and not by the consumer.

Poyry has modelled the interaction of volume and price risk over daily, weekly, monthly and annual prices to show the difference from half-hourly prices which arises. These are forecasts and the minimum that we would expect them to be factored into the PPA. A trader will also add an element of conservatism to these forecasts, along with additional balancing and trading costs. These discounts reflect the basis risk only, they do not incorporate suppliers' ability to impose discounts above cost reflexive levels within PPAs.

Capture prices (real €/MWh)	Hourly contract (GWA price)	Daily TWA contract	Weekly TWA contract	Monthly TWA contract	Annual TWA contract
2010	53.6	53.3	53.3	53.5	53.0
2015	51.1	51.3	51.7	52.3	51.4
2020	55.4	56.2	58.9	61.0	60.2
2025	70.1	71.0	74.5	77.3	76.2
2030	83.9	85.2	90.0	93.9	92.3
		daily TWA price x daily gen.	weekly TWA price x weekly gen.	monthly TWA price x monthly gen.	annual TWA price x annual gen.
Difference from hourly contract (GWA)					
2010	0%	1%	1%	0%	1%
2015	0%	0%	-1%	-2%	-1%
2020	0%	-1%	-6%	-9%	-8%
2025	0%	-1%	-6%	-9%	-8%
2030	0%	-2%	-7%	-11%	-9%

Wind revenue on market

CfD reference price

By setting the CfD on a monthly basis, we would therefore expect the trader to apply an additional discount of 11% which will be locked in for the whole of the PPA, irrespective of market, technological and Government policy changes that will occur between now and 2030.

Annex B

Implementing a Workable CfD

RES is keen to explore possible options for a Contract for Difference (CfD) as it is the preferred option for low carbon support as laid out in the Government's proposals for Electricity Market Reform (EMR). If a CfD type of support structure is implemented we are keen to ensure that it is workable, delivers the renewable energy targets and delivers good value to the consumer.

Whilst the high level concept of a CfD is very simple, such a system operating within the electricity market will be far more complex. Many of the factors which will be crucial to such a scheme's success and overall economic efficiency will be determined by the detail of the scheme. This paper attempts to explore some of those details.

We also outline some of the conditions required for a CfD to work. Without all these pieces we think there is a significant risk that the CfD structure will impose unnecessary costs to consumers and fail to deliver the necessary increases in low carbon generation anticipated. Some of the conditions needed, in particular the high levels of liquidity, are desirable in and of themselves.

We outline a number of possible CfD structures and provide commentary on their potential impacts. Wherever possible RES draws on its experiences in other markets to support the points made. This paper uses the logic of the supporting analysis, specifically that by providing generators with revenue certainty CfDs reduce investment costs which delivers low carbon deployment more cheaply than would otherwise be possible.

Summary

- The economic concept of a CfD is simple, but in reality a CfD would be a highly complex set of contracting arrangements. There is a risk of over-simplifying the mechanism.
- To prevent a CfD introducing inefficiencies in the market it is necessary to have high levels of liquidity.
- It is necessary to prevent basis risk under the CfD. This will require the CfD to be calculated on the same basis as generators' output is ultimately valued, on a half-hourly basis.
- In the absence of a liquid market it is necessary to retain an obligation on suppliers to contract with renewable generators.

CfD contract requirements

Whilst this is not an exhaustive list, the following requirements are our initial expectations on the necessary conditions for a CfD support mechanism to be implemented effectively and not increase the overall cost to the consumer.

1. *The CfD mechanism must not be over-simplified*

Conceptually making up the difference between an average price and a contract strike price seems straightforward. The reality of a CfD will, however, be a complex set of contracting arrangements. Undue complexity should be avoided. An over-simplified system which ignores the complexity of the market and potential contracting implications could lead to a number of unintended consequences.

To deliver the objective of revenue certainty to generators it will be necessary to mitigate a number of potential risks created by the CfD. These risks include;

- Basis risk – basing the CfD on a different index to the PPA terms and the risk of wind weighted average prices diverging from baseload prices over time.
- Tail risks - low probability but high impact events.
- Counterparty risk - ensuring sufficient confidence in the PPA and CfD counterparties
- Policy risk - protection against Government policy on revenues.

Mitigating these risks within the market is not an insubstantial undertaking. These risks are in addition to the balancing and transaction costs that exist at present, which are likely to rise in future. If these risks are not explicitly addressed the policy will not deliver the revenue certainty desired by policy makers.

2. *Basis Risk must be avoided*

To ensure CfDs provide the revenue certainty desired it is important that generators do not face basis risk under a CfD. Basis risk is the risk that the price referenced in the CfD is on a different basis to the one a generator realises and as a result a different value is realised. In GB electricity is traded on a half-hourly basis. The true value of a generators' output is therefore the sum of the price of the volumes produced by the generator in each individual half hour. This is different to the mean price over all half hour periods in a given month/year. The potential for difference between various price indices creates revenue risk. Suppliers mitigate this risk by applying discounts to the market prices they reference in PPAs.

3. *Obligation must remain on suppliers*

The PPA-based market has potential for substantial inefficiencies. There is a risk that, if the market remains uncompetitive and illiquid, once suppliers are no longer incentivised to contract with renewable generators the discounts they will apply to PPAs will increase. At present suppliers secure a financial benefit for contracting with renewable generators, specifically securing Renewable Obligation Certificates (ROCs), which offset their obligations under the RO. This financial benefit reduces the perceived transaction cost of contracting with renewable generators, particularly small ones. It creates some competition for PPAs, ensuring PPA terms are more favourable than they might otherwise be.

Independent developers and generators will be vital to delivering the renewable generating capacity required to meet the 2020 targets. Vertically integrated utilities, with many competing demands on their balance sheets, are only likely to be able to deliver a portion of the investment required. Creating a viable market position for independents is therefore vital to securing the investment required and doing so at competitive costs.

The requirement for an obligation on suppliers may be offset if market liquidity is increased to the point that a PPA counterparty is no longer required, i.e. the finance community is sufficiently confident that there is an liquid off-take market for projects to sell their output to directly.

4. *Liquidity is crucial to an efficient market*

The EMR supporting analysis assumed that the proposed reforms would be introduced within a liquid market. At present the GB market is highly illiquid, with essentially only balancing occurring on power exchanges.

A liquid market would increase the confidence that power could be traded effectively nearer to real time and would enable wind generators to better trade out forecasting errors. A highly liquid short term market (up to the final half hour prior to gate closure), should therefore reduce system imbalances at gate closure and would reduce the balancing costs of the system overall. It might be useful to compare balancing costs in the SEM in Ireland to those in the GB market.

There is however a risk that such a short term market would be dominated by low carbon generation and have depressed price relative to other time periods and the cost to the consumer will increase as a result. If this occurs then there would be an opportunity for dispatchable plant to contract in future trading periods at higher prices and be compensated against low prices in CfD reference price period.

A liquid market could also overcome the need for PPAs as a route to market. A highly liquid market could enable generators to operate on a merchant basis, selling power direct onto the market. This would allow generators to receive the full value of their power as the PPA discounts would be avoided.

The EMR proposals refer to Ofgem's review of liquidity which is taking place in parallel to the EMR. The scope of the review is limited and Ofgem is effectively judging the market that it has created. We are not confident that the review will deliver anywhere near the levels of liquidity needed, and in the timescales required, to implement the EMR proposals efficiently. Ofgem's review should be taken into the EMR process to ensure that the liquidity required for the EMR to deliver efficient outcomes is achieved.

The lack of liquidity in the market suits the vertically integrated players, as it allows them to increase the margins they are able to impose. It should, therefore, not be surprising that vertically integrated utilities are not calling for significant changes to be made to the illiquid structure of the electricity market that they dominate.

5. *CfD counterparty needs to be the Government*

Many of the risks which would need to be priced into PPA terms stem from policy risk. For example, the extent to which wind realises a lower average price than non-intermittent generators will be determined by the amount of wind deployed. This risk is dependent on the success of Government policy in delivering the targets (an incentive and planning policy risk) and the market's ability to adapt. In an uncompetitive PPA market these risks are likely to be over-priced by the market. The benefit of measures which avoid such risks materialising would be captured by suppliers, not consumers if they were locked into PPAs.

In addition tail risks such as generator or supplier failure risk are likely to be over priced by the market. If the CfD was paid via a supplier then the supplier would face potential liabilities if the generator failed at a time when payments to the CfD were required. This risk, whilst considered unlikely, could have a large impact on the returns achieved by the supplier from that PPA. In order to bear the counterparty risk, suppliers will require compensation. Alternatively the generator may face liabilities from the withdrawal of a supplier from the market (as with TXU in 2003). Due to the complexity of the arrangements and the low level of understanding of how the mechanism would work, such risks are likely to be over-priced in the market. It is therefore necessary for the Government to be the counterparty to those risks, which would entail it being the agency administering the scheme.

6. *Priority dispatch for low carbon generation*

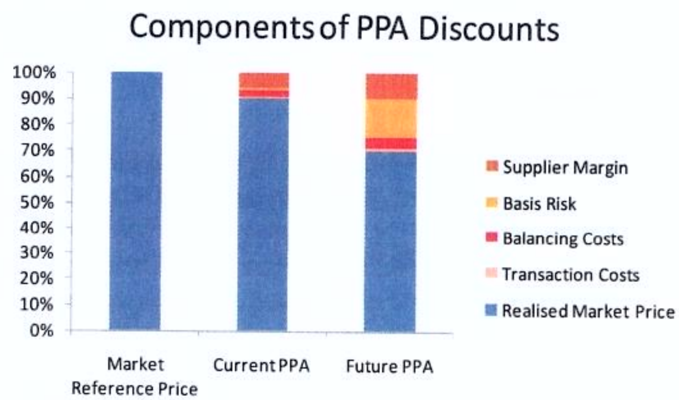
As low carbon generation increases its contribution to the generation mix, it will be very important that it should be dispatched as a priority to minimise any constraints and loss of CfD revenues arising from either constraints or grid curtailments. Priority dispatch is fundamental to this. In the SEM wind generators have priority dispatch and are classified as 'price takers'.

CfD Contracting Structures

Further requirements are likely to depend on the contract structures implemented as a result of the Government's proposals. Due to the lack of detail in the EMR document, we have described the current structure and then five possible alternatives under the CfD proposal.

Current contracting structure

The supporting analysis assumed that the EMR reforms would be operating within a liquid market. It did not consider the current contracting structures and the impact of an illiquid market on the efficiencies of the measures proposed.



At present most independent generators' route to market is via a PPA with a supplier. PPAs are typically agreed for around 15 years, over which the supplier agrees to pay the generator a fixed percentage of the market price for electricity and a fixed percentage of the ROC buyout, ROC recycle and LEC value. Established generators typically negotiate a discount of 10-15% on the wholesale price and a similar amount for the other elements. Smaller generators with less experience in the market are likely to see higher discounts.

In negotiations with PPA providers these discounts are normally justified as balancing and transaction costs. It sometimes suggested that the ROC discounts reflect the time value of money for suppliers paying generators ROC income on a monthly basis rather than at year end when the ROC value is realised. However, in reality suppliers collect RO costs from customers throughout the year, with minimal cost and risk associated.

There is also a supplier margin which reflects the market power of suppliers as a result of lack of competition and generators' reliance on suppliers as credit-worthy counterparties required to secure project finance. We therefore expect the removal of the obligation to lead to a significant deterioration in PPA values as suppliers increase their discounts to extract additional margins or merely seek to self supply. To some extent we can see this in PPAs terms we have been offered for recent projects.

The discounts applied within PPAs in the UK are far larger than in other markets in which RES operates. RES has financed a number of projects in Sweden, which is part of the highly competitive Nordpool electricity market. On Nordpool PPA discounts are typically very thin. PPAs are usually sought to cover balancing risk, preventing the generator having to trade in the market itself. Financiers typically only require PPAs for 5 years as opposed to 15 years in the UK. This reflects financiers' confidence over the liquidity and generators' long term route to market in Nordpool. The efficiencies such confidence in the market's liquidity brings are substantial.

Assuming that margins on Nordpool are competitive and there is no basis risk in the GB market between month-ahead PPA prices and half-hourly prices, it could be estimated that the level of PPA discount in the GB market is currently around three times greater than would be the case under more competitive market arrangements. These levels of margins represent a substantial cost on consumers.

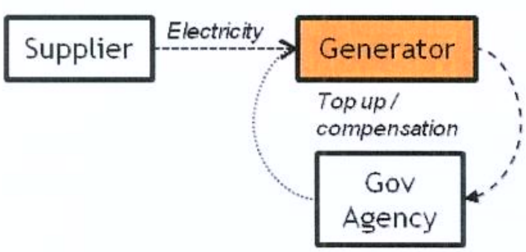
When renewables reach 30% of the market, if the current discount level of around 10% was maintained and applied to all renewable generators' revenues, supplier PPA discounts would represent around £1.2bn[2] per year. Assuming the difference between PPA discounts and actual costs are the same as the difference between costs in Nordpool and the discounts in GB PPAs, a cost reflective level might be around £400m. If the level of PPA discount increased, as is expected if the obligation on suppliers is removed, the difference between PPA discounts and actual costs would increase substantially. If PPAs were required to finance nuclear projects and a similar level of discounts was applied, the inefficiencies in the market would increase further. There are substantial efficiency gains to be made from improving the liquidity and level of competition in the wholesale market. This potential has not been considered in the EMR.

Possible Contracting Options for a CfD Structure
We have considered a number of possible structures for a CfD in the GB market. The following possible options are outlined below;

- CfD paid direct to generators with PPA (strike price based on market index)
- CfD paid direct to generators with PPA (PPA discount incorporated in strike price)
- CfD paid direct to suppliers
- CfD Paid to Supplier with Generator receiving a PPA for electricity and CfD separately
- Generators sell onto power exchange

When considering the impact of the various CfD structures on the current PPA based market we compare a situation in which there is no PPA discount, the current level of around 10% and a 30% discount which represents possible discounts if the obligation on suppliers was removed and competition and liquidity were not substantially improved.

1. Electricity PPA and CfD paid to generator (strike price set against market index)

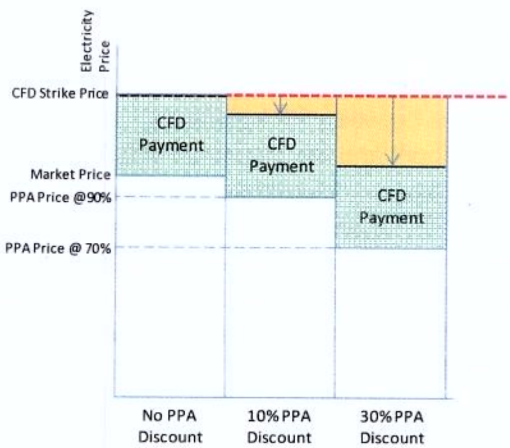


A Government agency administers the CfD and would transact with the generator direct, paying the difference between the market reference price and the CfD strike price. The supplier would contract directly with the generator for an offtake PPA.

As can be seen in the diagram, if there was no discount applied to PPA terms then the total revenues realised by the generator (solid black line) would be the full CfD strike price. However, as the PPA discount increases to 10% the total revenues realised by the generator reduces by the discount

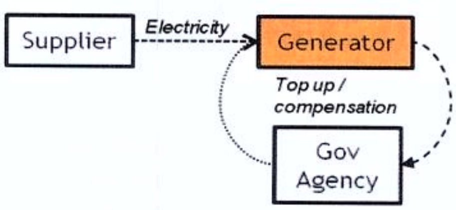
[2]Based on average renewable electricity revenue of £120/MWh and 100TWh renewable electricity production.

applied to market power prices. If the PPA discount increases to 30%, total revenues realised by the generator fall further still. The supplier margins increase accordingly.

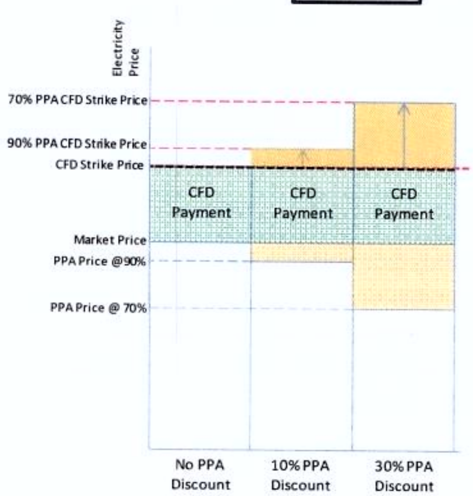


The PPA discount would have to be set at the start of the PPA and cover expected costs and risks of that offtake over the life of the PPA. These would include the balancing risk and the market risk (ie the wind weighted price compared to the time weighted price). Without effective competition we would expect the PPA providers to be very cautious and apply high PPA discounts. Estimating the scale and duration of those risks creates substantial opportunity for inefficiency.

2. Electricity PPA and CfD paid to generator (strike price incorporates PPA discount)



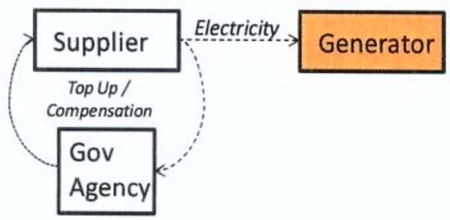
A variation of option 1 is that the CfD strike price could be made to reflect the value generators realise from a PPA rather than the headline market price. Suppliers' PPA discounts would be incorporated into the CfD strike price. Reflecting post PPA values into the CfD price would provide generators with revenue certainty, a key aim of a CfD. As can be seen in this diagram the revenues realised by generators (the solid black line) remains constant even when PPA discounts increase.

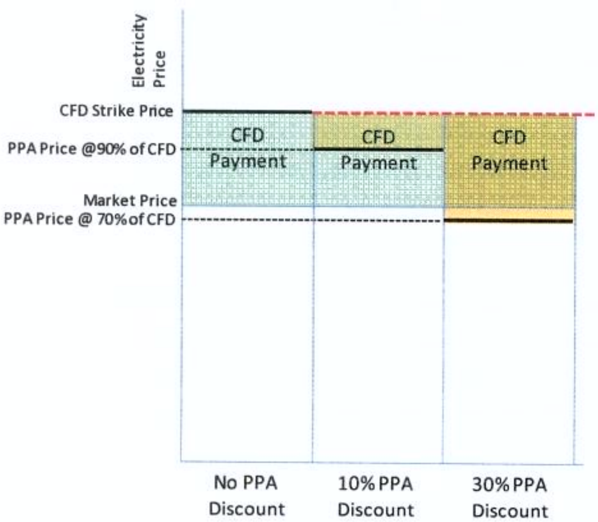


However, the CfD strike price has to increase as the PPA discount increases. There would be a substantial risk that the CfD strike price would lock inefficiencies into the system for the duration of the PPA.

In addition there would be almost no pressure on suppliers to limit the size of discount they applied to PPAs if they knew the discount would be incorporated into the CfD and passed through to consumers. Similarly there would be no incentive on generators to secure the best value PPA, as failure to negotiate beneficial terms would not impact the value they would realise. There appears to be an intractable difficulty in delivering revenue certainty with providing incentives within the market to minimise costs.

3. CfD Paid to Supplier with Generator receiving a single PPA covering electricity and CfD



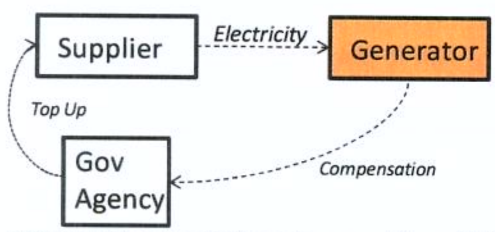


Another contractual structure would be for the CfD to be paid to the supplier rather than the generator. This could allow the supplier to offer fixed price PPAs to generators, albeit at a discount to the CfD strike price. This could achieve the objective of revenue certainty for generators.

Enabling suppliers to control generators' access to the CfD, as well as the market price, would increase suppliers' market power. This is likely to result in larger absolute value being captured by the supplier as the low level of competition in the market combined with generators' reliance on suppliers would not provide incentive to offer cost-reflective PPA terms.

Increasing suppliers' control over generators' revenue streams would further undermine generators' position within the market. It is therefore vital that generators have a direct contracting route to the agency administering the CfD.

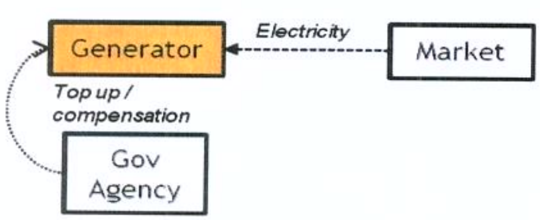
4. CfD Paid to Supplier with Generator receiving a PPA for electricity and CfD separately



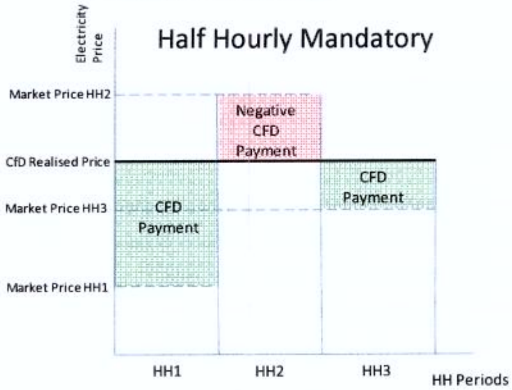
A worst case scenario is that the generator only receives a PPA for the electricity with payments from the Government agency going to the supplier but the generator, not the supplier, being required to pay the Government agency if the wholesale price exceeds the strike price.

In this instance the generator would receive a PPA (ie 90%) of the electricity price, and then 90% of the any CfD payments through, whilst being potentially liable for the full cost of any CfD recovery when prices exceed the strike price. Whilst we do not expect this to occur, it could lead to a significant disadvantage to any low carbon generation

5. Generators sell power on exchange, no PPA

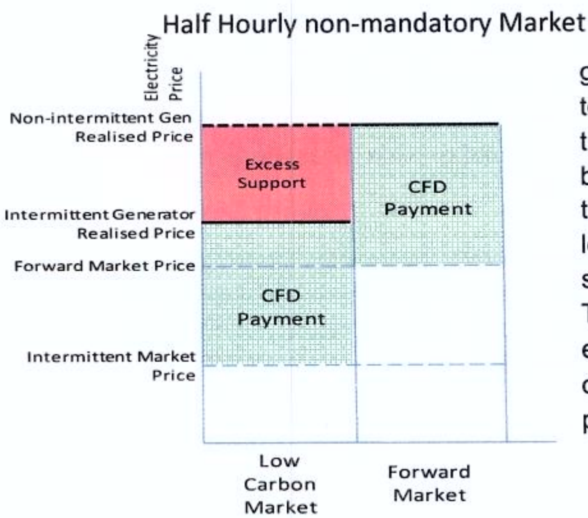


To circumvent the need for PPAs low carbon generators could sell their power direct into one of the power exchanges which operate in the UK at present such as APX. Singling out an exchange would draw liquidity into the market, as all CfD supported generators would sell onto that market. By



calculating the CfD payment for each traded period (each half hour), CfD generators would avoid all forms of basis risk. This would provide revenue certainty.

If a direct route to market approach was pursued it would be important for generators benefiting from the CfD to be required to trade on the exchange referenced by the strike price. This would bring liquidity to the market.



ading on the chosen exchange was not compulsory for CfD generators, non-intermittent low carbon generators would seek to 'beat the market' and trade on the forward market. Prices on the forward market are likely to be much higher than the CfD based market, reflecting the costs in the wider market such as the Carbon Price Support. The total revenue non-intermittent low carbon generators could secure would therefore be substantially higher than intermittent low carbon generators. The additional revenues from the forward market would provide excess revenues to non-intermittent generators. This would create unnecessary cost to the consumer as they would be paying for the CPS and CfD for the same unit of electricity.

Conclusions

From our initial analysis we can see that;

- To avoid market inefficiencies under a CfD it is vital to have a highly liquid and competitive market. It seems highly unlikely that the GB market will achieve such levels of liquidity in the timescales needed by the EMR. Without a highly competitive market in place it is likely that the proportion of revenues realised by generators under a CfD would fall as suppliers extracted greater rents via PPA terms. This would create unnecessary cost to the consumer.

- To ensure revenue certainty it is necessary to avoid basis risk. This requires the CfD strike price to reference the same market price as the generators supported by the CfD realises. Given that half-hourly market prices are likely to be required for efficient low carbon dispatch and to avoid basis risk, the CfD will need to be calculated on a half-hourly basis. Half-hourly calculation of CfD payments could be seen as overly complex.

- There is a trade off between revenue certainty and the ability to incentivise generators via market signals. Under a CfD which delivers true revenue stability generators will be isolated from the effects of the market price, as they will be made good to the strike price. They will remain exposed to balancing risk.

- There is a trade off between the level of sophistication required for a CfD to deliver the de-risked revenues required by institutional investors and the complexity of the system.

Institutional investors, which require de-risked revenues, are likely to find an overly complex system unattractive.

Our expectation is that the most effective form of supporting renewables through a CfD would be option 5 – a CfD set against a half-hourly price index, within a highly liquid and competitive market which is mandatory for all low carbon generators receiving the CfD, with the Government or a Government agency as the counterparty and the CfD level is set by independent review. However there are still potential issues with this approach, that include;

- Requiring all CfD supported low carbon generators to sell into the chosen exchange would provide greater liquidity and prevent non-intermittent low carbon generators securing the double benefit from higher forward prices and the high CfD payments. It would however, increase the number of generators without an incentive to operate optimally.

- If payment of CfD was based on output rather than availability it would be rational for all generators on the low carbon exchange to bid in negative infinity if that meant they would be dispatched. This could lead to very high compensation payments. However, availability or capacity based payments could prevent this.

- Balancing costs would not be borne by the low carbon generators on the exchange. However, arguably it is more efficient if balancing costs are borne by consumers as the market is likely to incorrectly price them and the scale of balancing costs is largely a policy risk.

Annex C

Concerns with Redpoint's Analysis supporting the CfD proposal

The justification for the Government's preferred option of a Contract for Difference (CfD) to support low carbon generation is set out in the supporting analysis undertaken by Redpoint. Given that the move towards a CfD is so significant and will create such uncertainty in the market, it is important that the robustness of the supporting analysis is scrutinised.

The Redpoint report sets out the case through which the CfD increases investor confidence in investing in new capacity. This reduces their required rate of return on new projects and therefore allows the investor to make their investment earlier (rather than waiting for higher prices) and the cost to the consumer is lower (as the level of support is low). Under the CfD proposal the reduction in hurdle rate both reduces the investment cost and reduces CO_2 emissions compared with any other supporting structure.

Unfortunately RES considers the case made by Redpoint to be at best overstated, and possibly fundamentally flawed. It overstates the reductions in hurdle rate and therefore overstates the level of carbon savings and cost that could be achieved from greater levels of revenue certainty.

1. The reduction in the cost savings are over stated because;
   - The methodology for determining the reduction in hurdle rate does not relate to standard investment analysis.
   - It does not take into account the risk profiles of the generating unit;
   - It does not take into account the impact on PPA contracts
   - It does not take account of the increase in returns required on the remaining equity in a project if the level of debt increases
2. The benefit in terms of carbon savings are overstated due to;
   - It does not allow for the fact that increases in carbon price support are already factored into investment decisions,
   - It does not take into account the likelihood of a development hiatus

This paper looks at each of these in turn.

Reduction in Cost Savings

Much of the case for a CfD stems from one primary assumption; that the cost of investing in low carbon projects can be done more cheaply under a CfD. The reduction in investment costs results from the expectation that by reducing revenue uncertainty projects will be able to leverage more debt into projects, reducing the required hurdle rate for investment will reduce as a result. Whilst we agree that such an impact is possible we consider that the scale of the impact outlined in the modelling is substantially overstated.

Hurdle rate methodology

Working through the hurdle rate methodology as given in appendix D of the Redpoint report allows us to determine the assumptions that have been used. We have presented our calculations in the appendix for review. However this reveals the following problems;

- *Inferred equity returns are very high.* Redpoint uses an investment beta to reflect technological risk. The equity IRR for an independent generator varies from 18%, 25% to 32% for a mature, established and emerging technologies. These are completely out of kilter with expected equity returns. RES regularly project finances its operating assets and as such the equity return is a key investment criteria for us. It is concerning that such a crucial input to the modelling is not supported by any justification or explanation. RES has financed many renewable energy projects. We do not consider that the financing case derived from the investment assumptions is credible.

- *Low level of project gearing for independents.* The modelling assumes 70% debt can be raised by independent developers. RES, an independent developer, is able to achieve significantly higher debt levels than this. Even under very conservative investment scenarios we would expect new projects to be financed using at least 80% debt. Typically projects are financed using the maximum level of debt that the bank is willing to accept, as they want to retain a level of equity from the project sponsors. The low initial level of project debt unreasonably creates an inflated scope for reductions in financing costs, and therefore hurdle rates, than is really the case.

- *Implausible debt service cover ratios.* The assumption that a 1% reduction in revenues at risk leads to a 1% increase in the amount of debt that can be secured is a highly subjective assumption. No evidence is provided to justify this assumption, yet it is crucial to the whole analysis. The Redpoint analysis suggests that as a result of the reduction in debt, a 1.4% reduction in Weighted Average Cost of Capital (WACC) for onshore wind projects can be achieved. Back calculating this using recent project finance terms suggest that to achieve this increase in debt the Debt Service Cover Ratio (DSCR) would have to be reduced from 1.4 (the amount typically available in the market today) to 1.2. This is not a plausible expectation.

Lower DCSRs are possible in very low risk markets, but only when based on conservative wind yield projections. The energy yield is around 10-11% lower in the most conservative projection, compared to the mid estimate typically used for financing. Greater certainty on energy yield allows for the higher DSCR, rather than revenue stability alone. In Sweden DSCRs tend to be higher as project finance is less developed, and because of the volatility of the green certificate and Nordic electricity price.

Risk profiles of the generating unit

The Redpoint analysis assumes that all the risks faced by the generator have a normal distribution (ie have an equal probability of achieving either a higher or lower value). This is not a representation of risk that we would recognise. Rather we typically find that many of the risks are skewed such that the value potential is significantly weighted either positively or negatively. Typically the costs (maintenance costs, grid costs, grid availability, taxes and business rates) are negatively skewed, and energy yield is normally distributed. As an independent generator we consider the electricity price to have a positive skew. If the electricity price is fixed, then the generator is only left with downside risk and it is likely this will minimise any benefits of revenue certainty.

Impact on PPA Contracts

In most instances the analysis assumes there is a competitive market and PPA terms are perfectly efficient. It states that nuclear stations might have difficulty in securing PPAs and suggests that this is a market failure (although in reality the new nuclear consortia are vertically integrated utilities with offtake risk mitigated by demand). However, the analysis does not consider the impact of PPA terms for independent generators, in particular the impact of withdrawing the obligation from suppliers and the implications this will have on PPA terms. This is a substantial oversight as it is likely to have a substantial impact on the economic efficiency of all the proposals considered.

Increasing debt leads to increases in the returns required for the remaining equity

Increasing the proportion of debt in a project reduces the level of equity. The lower the proportion of equity, the greater the risks are to that equity, as it is subordinate to the debt. Any reduction in the project's revenues will, therefore, hit the equity holder's returns before the debt holder's. As a result the equity holder requires greater returns the more debt is included in a project. The increased required returns to equity would partly, if not completely, offset the reduction in hurdle rate resulting from the increase in debt. This effect does not appear to have been taken account of in the calculation of the hurdle rate. The analysis just calculates the impact of the increased debt; it ignores the corresponding increase in returns required on the remaining equity.

Reductions in Carbon Emissions

Whilst the majority of the carbon emissions are brought about by the reduction in hurdle rates, which we have already largely discounted, there are some additional points that suggest the carbon savings are not going to be all that are claimed.

Carbon prices are already factored in

The Redpoint analysis assumes that some investors who would potentially benefit from increases in carbon prices have little confidence in the long term carbon price, whereas those who might be negatively impacted have far higher levels of confidence.

It is important to recognise that many renewable energy investors have been factoring in increases in carbon prices to their financing case for a number of years. The market's leading provider of electricity price forecasts has been factoring in increases in carbon prices out to 2030 for since 2008, before any Government supported level was suggested.

In the supporting analysis to the EMR consultation the impact of low investor confidence in future carbon prices was investigated. Perfect foresight of future carbon prices was not investigated. It is highly likely that perfect foresight would require a far lower level of carbon price to achieve the same outcome. The lack of confidence of certain investors therefore represents a substantial inefficiency in the market and should be addressed.

Impact on development and investment of assets

Whilst the Redpoint paper acknowledges the risk of a delay to investment due to uncertainty in the market it does not reflect the impact of this in the carbon emissions. In particular it does not appear to acknowledge the fact that a fundamental reform of the electricity market as proposed under the implementation of the CfD structure is likely to have a significantly greater impact on investor uncertainty compared to a relatively modest change such as the Premium FIT with a continuation of obligation.

Conclusion

Based on our experience we consider the logical arguments put forward by the Redpoint report to be lacking an effective coherence with the market which we either operate in or would envisage as a result of the proposed reforms.

As we do not have confidence in the underlying methodology we can't have confidence in either the proposed carbon or proposed cost savings. If these savings are unlikely to materialise, and we expect significant risks of disruption and deteriorating PPA terms then it opens the question as to whether these risk of the proposed reforms outweigh the potential benefits.