ANNEX B

FEED-IN TARIFF WITH CONTRACTS FOR DIFFERENCE: DRAFT OPERATIONAL FRAMEWORK

CONTENTS

INTRODUCTION

1. *Planning our electric future: a White Paper for secure, affordable and low-carbon electricity*[1] set out the Government's intention to introduce a Feed-in Tariff with Contracts for Difference (CfD) as a new mechanism to support investment in low-carbon electricity generation. The CfD works by stabilising revenues for generators at a fixed price level known as the 'strike price'. Generators will receive revenue from selling their electricity into the market as usual. However, when the market reference price is below the strike price they will also receive a top-up payment from suppliers for the additional amount. Conversely if the reference price is above the strike price, the generator must pay back the difference.

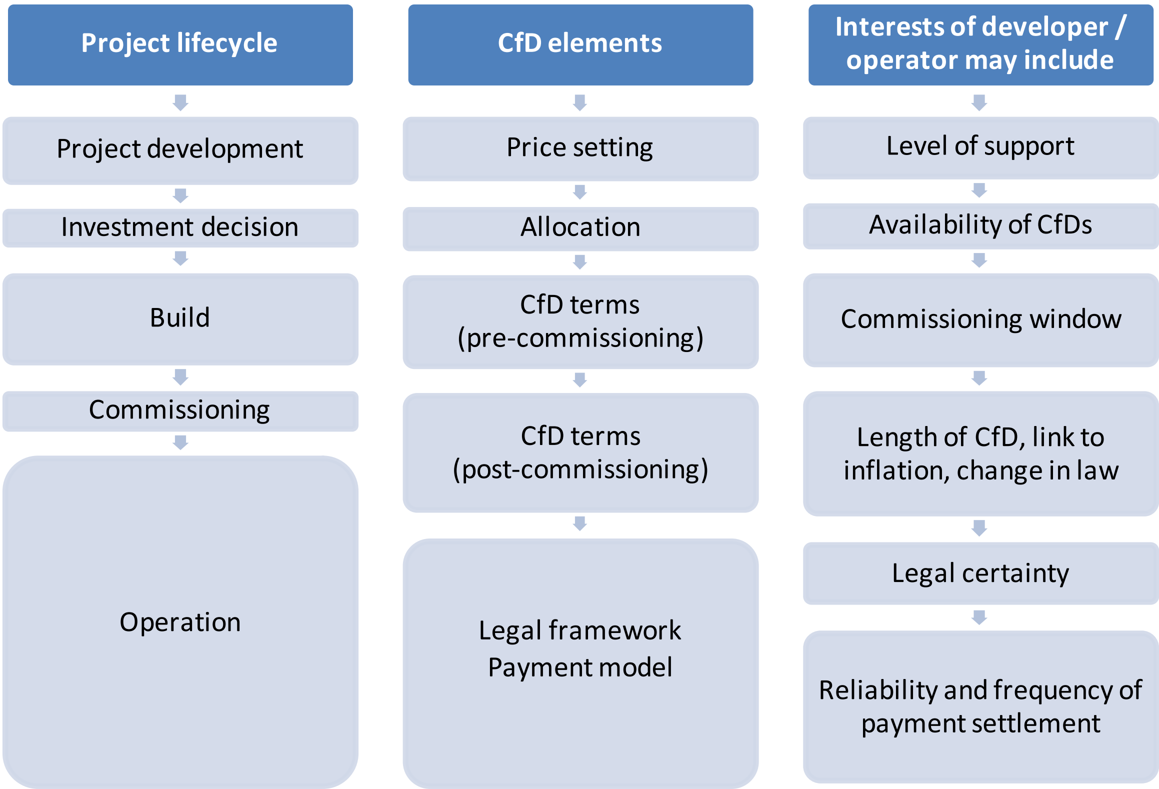
2. These characteristics mean that the CfD provides additional benefits when compared with the current Renewables Obligation and alternative mechanisms considered. It gives greater certainty and stability of revenues by removing exposure to volatile wholesale prices, and protects consumers from paying for support when electricity prices are high. Consequently it makes the development of low-carbon generation cheaper for both investors and consumers.

3. This document sets out the emerging position on the detail of how the Government envisages the CfD system will operate, structured around four core elements:
    - The process for determining CfD strike prices (Section A).
    - The system for allocating CfDs (Section B).
    - The key terms of the CfD including CfD length, reference price source and others (Sections C and D).
    - The institutional and legal framework underpinning the CfD, and the payment model for enabling financial flows between suppliers and generators (Section E).

4. This structure mirrors the developer's journey from project inception, through construction and commissioning, to having an operational low-carbon facility. The chart below sets out in broad terms how the document and the project lifecycle are linked, and gives a non-exhaustive indication of the key interests of developers in each section.

[1] http://www.decc.gov.uk/assets/decc/11/policy-legislation/EMR/2210-emr-white-paper-full-version.pdf

Figure 1: CfD elements linked to project lifecycle and developer interests



5. The CfD operates within the broader electricity market, and successful implementation of the CfD regime requires the market to operate efficiently. This document therefore also discusses route to market and liquidity questions (Sections F and G).

6. The UK Government is fully committed to ensuring that the Devolved Administrations are engaged in a meaningful way during the development of the EMR arrangements, whilst fully respecting the existing devolution settlements. Section H signposts areas of the annexes which have particular relevance to the Devolved Administrations.

7. In some sections of the document, a number of options are presented for how a desired outcome could be achieved, for example on how to control the costs of decarbonisation to ensure that consumers' interests are protected and to provide developers with confidence in the durability of the mechanism. Other sections describe the proposed approach for implementing the CfD. The Government would welcome input from industry on all of these proposals, to ensure the aim of introducing a credible and durable system is met. In addition the proposals will benefit from the views of the Energy and Climate Change Select Committee as the draft Energy Bill goes through the pre-legislative scrutiny process. Over the coming months the detailed design will continue to be developed, with a view to publishing a final CfD Operational Framework in the autumn.

8. The emerging position on the key CfD design features is set out in the following table[2].

Table 1: Key features of the CfD

Feature	Description	Emerging proposal
Price setting and allocation		
Administrative price setting	How strike prices will be set for different technologies.	Renewables: similar to RO banding review process. CCS: initially through the CCS Commercialisation Programme competition in conjunction with the FID Enabling process. Nuclear: initially on a project by project basis, through the FID Enabling process.
Competitive price setting	When and how strike prices will be set using a competitive process.	Move to competition as soon as market conditions allow; this could be 2017 for certain renewable technologies.
Eligibility	Which technologies will be eligible for support under the CfD regime.	Minded that new low-carbon technology plants that are not eligible for the small-scale FIT will be eligible for a CfD.
Allocation	How developers can apply for a CfD before the move to a fully competitive process.	Renewables: through allocation rounds run every six months. CCS: initially through the CCS Commercialisation Programme or the FID Enabling process. Nuclear: initially through the FID Enabling process.
Managing financial exposure	Ensuring costs of CfDs remain affordable.	Minded to instruct the System Operator to remain within an agreed budget when issuing CfDs. Considering whether further controls are required for particular technologies.
CfD terms		
Pre-commissioning	The arrangements for monitoring the development of plant after CfD award.	Minded to place obligations on developers to build within agreed timescales, with proportionate penalties to incentivise compliance.

[2] The Government has been advised in developing these proposals by Cambridge Economic Policy Associates and ESP Consulting.

Feature	Description	Emerging proposal
Reference Price	The market price for electricity that is referenced in the CfD for the purpose of calculating CfD payments.	Intermittent: Hourly Day Ahead Auction Price for the GB Zone (as established under North West European Market Coupling). Baseload: Year Ahead, price source to be determined.
CfD Volume	The definition of the volume of electricity for the purpose of calculating CfD payments, and the resulting metering requirements.	Minded to pay the CfD on the basis of metered output unless the price in the reference market is negative, in which case to pay on a measure of availability.
Allocation of supplier payments	How suppliers' payment obligations / entitlements are calculated.	Minded to base suppliers' payment obligations on market share (as defined by 'supplier cap take').
Settlement	Process and timing for invoicing and administering CfD payments.	Minded to base processes on Balancing and Settlement Code processes. Minded that settlement periods will be monthly or possibly shorter.
CfD Length	The length of the CfD from the payment start date as defined in section C.	Initial view that CfD length for renewables should be 15 years. 10 years (subject to negotiations) for early stage CCS project(s) supported under CCS Commercialisation Programme. Nuclear and long-term CCS-equipped plant to be determined.
Inflation indexation	Arrangements for adjusting the CfD strike price in line with inflation.	Minded to choose CPI as a standardised and established inflation measure that is familiar to international institutional investors.
Fuel Price indexation	Arrangements for adjusting the CfD in order that payments reflect a generator's input fuel costs.	Minded not to link the CfD strike price to fuel costs for biomass. For the first CCS project(s), minded that the CfD should provide indexation needed to hedge against long term fuel price variability.
Credit and Collateral	The requirements on generators and suppliers to provide credit / collateral.	Minded to place a collateral requirement based on an estimate of likely settlement amounts due in a given trading (settlement) period.

Feature	Description	Emerging proposal
Amendment of the reference price and other CfD parameters	The arrangements for amending CfD parameters in response to changes which might impact the validity of the indices used.	Minded to include an 'independent expert' role in the CfD framework to manage any review of CfD parameters and determine any amendments required.
Change in Law	Arrangements for adjusting the CfD in response to relevant changes (e.g. regulatory) that materially affect the value of the CfD to either party.	Minded in principle that the CfD should contain change in law provisions, the form and scope of which remain to be determined. Further detail will be set out in the autumn.
Dispute Resolution	Procedures for resolving any disputes arising under the CfD.	The Government will seek further legal advice in this area before engaging with stakeholders later in the year.
Legal Framework and Payment Model		
Legal status of the CfD	The arrangements for promoting investor certainty.	The draft Energy Bill outlines that the CfD will be an instrument created by statute that sets out obligations on suppliers and generators. However, Government is considering industry concerns around whether a conventional contractual model would be preferable.
Route to market and liquidity		
Route to market	Independent generators are often reliant on Power Purchase Agreements to secure project financing.	The Government plans to issue a call for evidence in June 2012 to set out understanding of the issues, the evidence that is needed to move forward, and to outline initial options that may address market concerns.
Liquidity	A liquid electricity market is an important factor underpinning the operation of the CfD.	Government welcomes recent positive developments in the markets, but believes further measures are necessary and will work with industry and Ofgem to ensure liquidity strengthens.

A. PRICE SETTING

The level of support for low-carbon generation will be set according to a series of principles, foremost amongst which is the need to deliver decarbonisation whilst minimising costs to consumers. The Government's position remains that the best way to do this in the long term is through competitive price setting, but until market conditions can support such processes, prices for all low-carbon technologies will be set administratively or through negotiation.

During Stage 1 (to 2017) – for renewable technologies the initial process will be similar to that used for the most recent Renewables Obligation banding review, giving visibility of prices for a five-year period to enable planning. Strike prices for early stage CCS projects (including those supported under the UK CCS Commercialisation Programme) and nuclear projects will be determined through cost, risk and price discovery processes and negotiation.

Stage 2 (2017-2020s) – as technologies and the market begin to mature, the Government intends to begin to move to a competitive price discovery for specific technologies. For renewable technologies deploying after 2020 it is expected this may begin as soon as 2017.

Stage 3 (2020s) – technologies and the market have matured sufficiently for Government to move to technology-neutral competitive price setting.

Stage 4 (late 2020s and beyond) – CfDs no longer needed, as market sufficient to drive competition.

Principles

1. The levels of support required to ensure the transition to a decarbonised electricity market (and to achieve carbon and renewable energy targets) must take account of two core objectives: minimising costs to consumers and reducing uncertainty for investors. There are costs to replacing the UK's ageing energy infrastructure with low-carbon alternatives, and the Government will aim to minimise the impact of its policies on the costs that consumers and businesses pay. Giving advance visibility of the support available, and when and how prices may change, will provide developers with the clarity they need in order to plan their projects and take investment decisions.

2. Delivering these objectives will lead to a CfD regime that is credible and durable. A scheme which fails to manage costs effectively would soon lose support amongst the wider public, and cause uncertainty for developers about whether

support levels could be sustained. The Government is focused on delivering a system which both controls the impact on consumer bills (in line with the budgetary constraints that DECC has to operate within) and ensures that the commitments made under the scheme can be honoured.

3. Certainty and stability are crucial for investors to be able to make their decisions. Therefore once a project has demonstrated eligibility, been awarded a CfD at a particular strike price, and met any commissioning requirements it will receive that strike price for the duration of the CfD (barring any adjustments that are provided for within the CfD, such as inflation indexation or change in law).

4. Securing the UK-wide operation of the CfD is important and work is ongoing with the Devolved Administrations to deliver this. The UK Government is fully committed to ensuring that the Devolved Administrations are engaged in a meaningful way during the development of CfD strike prices, whilst fully respecting the existing devolution settlements. In practice, this means that the Government will consult with the Devolved Administrations in setting strike prices for renewable technologies, and will make a decision on Northern Ireland strike prices in conjunction with Northern Ireland Ministers. Market arrangements within Northern Ireland are different to those in the rest of Great Britain. This is as a result of its membership of the Single Electricity Market (SEM). UK-wide strike prices are preferable but in the event that relevant differences in market conditions require it, CfD strike prices in Northern Ireland may be slightly different to those in the rest of Great Britain to reflect those differences. It should be noted that Northern Ireland will introduce the CfD later than Great Britain and no earlier than 2016. Further detail on the Northern Ireland timeline will be provided by the Northern Ireland Executive. See Annex A on the EMR Institutional Framework for further detail on arrangements in the Devolved Administrations.

Competitive price setting

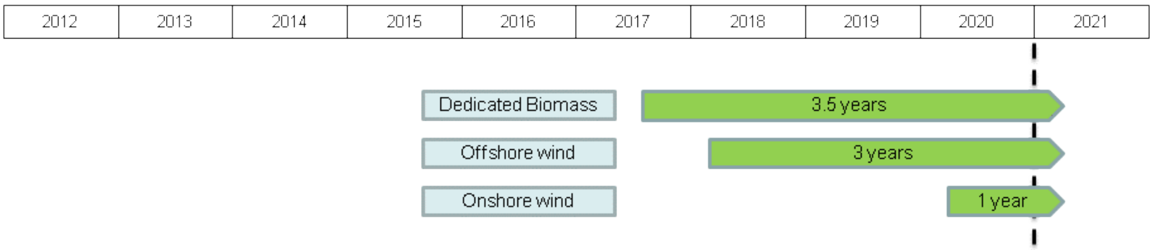
5. Government has been very clear about the intention to move to a competitive price discovery process for all low-carbon technologies as soon as practicable. Introducing tenders or auctions should enable the market to set financial support at a level just high enough to promote deployment. As a result of competition, bids are driven down to the optimal level of support in order to meet statutory renewable and decarbonisation targets. This is likely to involve technology-specific competitions initially and could occur as soon as 2017. In the longer term, it is expected that technology-neutral competitive processes will be introduced in the 2020s.

6. The EMR White Paper set out the criteria that need to be met before it would be possible to introduce competitive price discovery through auctions or tenders. These include:
    - having confidence that there are enough potential participants in the auction or tender for there to be competitive tension;
    - knowing that the development capacity of the potential participants exceeds the volume of new development sought in a given time period or tendering round; and
    - knowing that the projects or technologies eligible for the tender or auction are comparable, so that the strike price is a meaningful way to discriminate between them.

7. Government will use these criteria to provide its assessment of whether technologies are ready to move to competitive price setting. Government will set out in the delivery plan and annual updates the proposed timescales and any decisions on moving to auctions. The System Operator may be asked to provide evidence for technologies' readiness for competitive price setting as part of their delivery role.

8. Given the EU 2020 Renewables Target, the different build times and stages of development of technologies, it is not deemed appropriate to set a hard deadline for transition to competitive price discovery for all renewables; instead a phased transition seems preferable and necessary. It is therefore proposed to introduce competitive price discovery as technologies demonstrate that they have met the above criteria and once their build times mean that they would be unable to commission in time to meet the deadline for the 2020 Renewables Target.

    Figure 2: Showing different renewable technologies moving to competitive price setting depending on their average build times



9. Adopting this approach has a number of potential benefits as follows:
    - it facilitates a move to competition as soon as market sectors will allow;
    - it reduces risk of hiatus caused by a pre-announced hard transition date for all technologies, whilst giving indicative dates for specific technologies;
    - it retains flexibility around the 2020 Target by allowing technologies with shorter build times to come forward 'unconstrained'; and
    - it does not stifle nascent technologies.

10. For nuclear generation the major issue will be whether there are enough competitors to allow competitive price discovery. This is likely to be exacerbated by the fact that there are limited sites, all of which have differing characteristics, and the sites are not freely transferable, and the timescales for building nuclear generation mean it is unlikely that projects will be competing for the same slots. Government will continue to consider the feasibility and desirability of introducing a competitive element for nuclear projects, and will do so as soon as appropriate.

11. There is already a competitive element in the setting of the support level for early stage CCS projects bidding into the CCS Commercialisation Programme, as this will be determined as part of the Programme competition in conjunction with FID enabling processes. Beyond the Commercialisation Programme the strike price is expected to be the key factor in deciding which CCS projects to support, before competition with other technologies with similar generation characteristics is introduced.

12. Prior to the introduction of competitive processes, prices for all low-carbon technologies will be set through an administrative, or negotiation, process, as set out in the following sections.

Administrative price setting for renewable projects

13. In the administrative price discovery process for renewable generation the support level will be set by the Government, informed by evidence and analysis from the System Operator. This will form part of the process for developing the delivery plan and annual updates, as described in Annex A on the EMR Institutional Framework. Developers will then bring forward those projects they believe they can build at that price and apply for a CfD. The detail of the allocation process options under consideration is set out in section B of this document.

14. For the initial CfD price setting process for renewables, the process will be similar to the most recent Renewables Obligation Banding Review, and much of the same data will be used to ensure consistency between the two schemes. However, additional data will be required to cover the pricing period beyond 2017. Adjustments will also be made where appropriate, to reflect the different nature of the CfD mechanism; for example adjusting analysis to account for the lower cost of capital available under the CfD.

15. The System Operator will be commissioned to conduct analysis and issue a call for evidence from industry on both the market costs of building each of the renewable generation technologies eligible for support under the CfD, and their

deployment potential (taking account of wider impacts and constraints). This data will then be used to model the renewable electricity market, including a forecast of the levelised cost (including capital, fuel, operating and maintenance costs) per MWh of each renewable technology. Cost benefit analysis will be carried out based on this model to examine the impact of different strike prices on deployment and Government's objectives (security of electricity supply, meeting renewable and decarbonisation targets, and minimising costs to consumers). The Government will also appoint a Panel of Technical Experts to review the System Operator's analysis and scrutinise the process, as set out in the Annex A (EMR Institutional Framework). The System Operator will then submit its analysis and the Panel of Technical Experts will report to the Government.

16. The Secretary of State will make a decision on the strike prices necessary to best balance the range of relevant strategic objectives, informed by the evidence and analysis from the System Operator, the report from the Panel of Technical Experts and other experts such as the Committee on Climate Change as necessary. The Government will publish the proposed strike prices in the draft delivery plan, through which the underpinning evidence and analysis (e.g. the cost and deployment data) will be consulted on. Decisions on the strike prices will be made in consultation with the Devolved Administrations. The first delivery plan, including the final renewable strike prices, will be published in late 2013. More detail on this process is in Annex A (EMR Institutional Framework).

17. Government and the System Operator will continue to monitor the costs of technologies to ensure that changes in price in the market can be reflected when setting new strike prices for future years. As part of this, post-construction validation of costs will be employed to check information provided and gain a greater understanding of the trends in costs, and all projects in receipt of CfDs will have a duty to provide cost data in subsequent cost gathering exercises.

18. The Government recognises that providing developers and investors with sufficient visibility is a key part of creating an environment in which they can make investment decisions. To facilitate this it is proposed that five years of strike prices for renewables will be published in the delivery plan in late 2013 (i.e. from the start of the CfD regime in 2014 until 2018). Earlier visibility will be provided through indicative prices in the draft delivery plan, published in mid 2013, to allow developers to prepare their investment plans accordingly. As set out in Annex A (EMR Institutional Framework), the Government is doing further work on the necessary process and how long it will take to produce the first delivery plan, and to assess the impact of the proposed timing, before confirming the timeline and process, objectives and parameters later in 2012.

Figure 3: Indicative timeline for strike price setting for 2014 to 2018

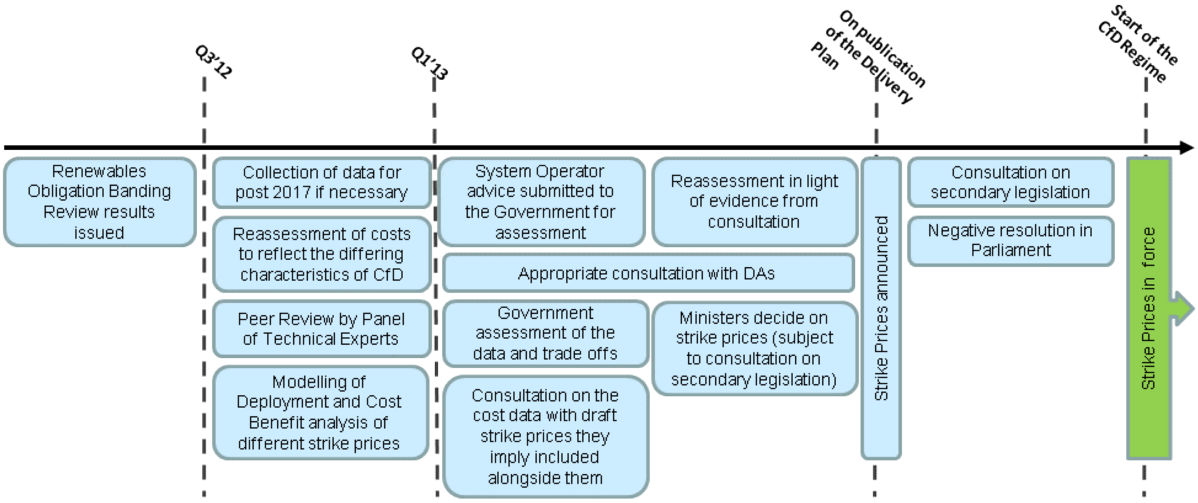


Table 2: Indicative timeline for strike price setting for 2014 to 2018

Date	Activity
Before summer recess 2012	RO Banding Review decision published with underlying data.
Summer 2012	Government commissions the System Operator to review RO Banding data and gather any additional evidence, including data to cover pricing period beyond 2017.
Late summer 2012	The System Operator carries out the review of costs (appointing consultants if required) and issuing call for evidence.
Summer / autumn 2012	System Operator carries out analysis to identify differences between RO Banding assumptions and CfD strike price assumptions, e.g. including cost of capital.
Summer / autumn 2012	Industry provides cost data to the System Operator responding to call for evidence. System Operator uses data to generate indicative strike prices.
Early 2013	System Operator carries out further analysis, including on impacts of different strike prices on Government objectives, reviewed by Panel of Technical Experts.
By mid 2013	The Secretary of State considers the System Operator's analysis and carries out consultation on data and underpinning analysis with draft delivery plan.
By late 2013	Government makes final decision on strike prices, following appropriate consultation with Devolved Administrations, and publishes as part of the delivery plan consultation.
Early 2014	Government introduces and consults on secondary legislation on the broader CfD regime and strike prices.
Mid 2014 (TBC)	Start of CfD regime: strike prices in force.

19. In order to maintain sufficient visibility in the run up to 2020, it will be necessary to administratively set prices for 2019 and 2020 for those renewable technologies that have yet to move to competitive price discovery. This further price setting process is anticipated to be broadly the same as set out above, although with a fresh collection of the most up-to-date cost and deployment data available.

20. At the same time Government will verify that strike prices for projects coming forward in the period up to 2018 remain appropriate. The assumption would be that strike prices would not be changed, however, if there was clear evidence of a change in technology or other costs, Government would consult on these costs ahead of making any appropriate adjustment.

21. Strike prices offered for technologies are expected to decrease (in real terms) over time (with projects delivering in future years getting a lower strike price, if appropriate, than those delivering in the nearer term), reflecting cost savings from learning or growth in supply chains. In the event that there is evidence that costs of building generation for specified years have changed, the strike prices available to new projects yet to secure a CfD for those years may be revised, to ensure continued deployment at best value for money to the consumer. It is important to note that projects that had already been issued with CfDs at that point would continue to receive the level of support originally agreed for the full length of the CfD.

22. In order to provide industry – especially technologies with longer build times – with sufficient visibility, Government would expect strike prices for the years beyond 2018 to be published in 2015 in the annual update to the delivery plan. It is expected that the process would be as follows:

Figure 4: Indicative timeline for strike price setting for 2019 and 2020

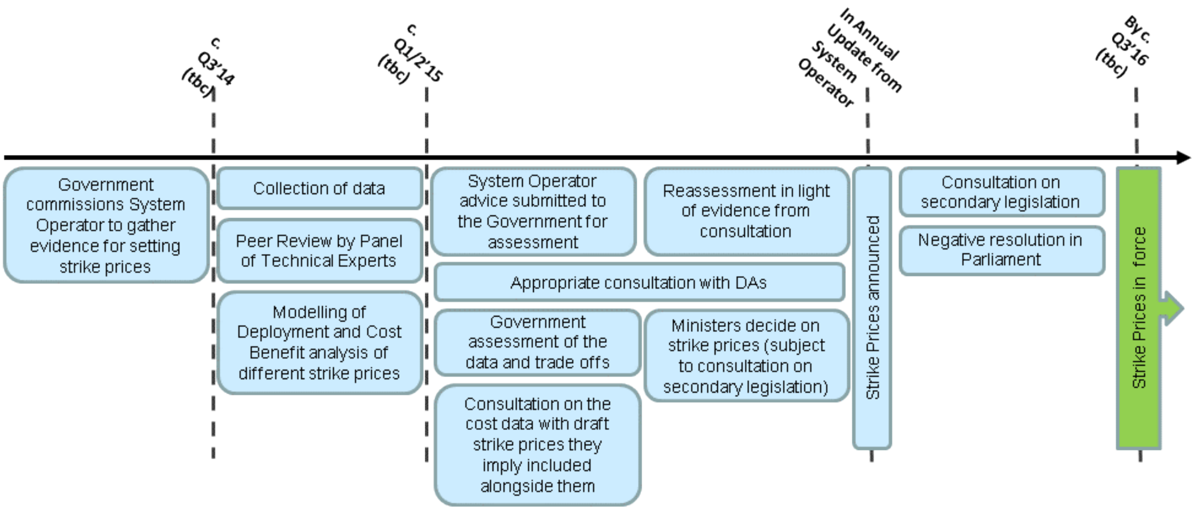


Table 3: Indicative timeline for strike price setting for 2019 and 2020

Date	Activity
Mid 2014	Government commissions the System Operator to gather evidence and produce analysis on renewable strike prices.
Mid to late 2014	The System Operator carries out the review of costs (appointing consultants if required).
Late 2014	Industry provides cost data to the System Operator through a call for evidence.
Early 2015	System Operator uses evidence to carry out further analysis, including on impacts of different strike prices on Government objectives, reviewed by Panel of Technical Experts.
Mid 2015	The Secretary of State considers the System Operator's analysis and carries out consultation on data and underpinning analysis.
Mid to late 2015	Government makes final decision on strike prices, following appropriate consultation with Devolved Administrations, and publishes in annual update.

23. As before, the Secretary of State (in consultation with Devolved Ministers) will come to a view on the set of strike prices which most effectively deliver an appropriate balance between the strategic objectives whilst bringing forward sufficient levels of deployment to achieve decarbonisation and renewable targets.

24. Draft strike prices for 2019 and 2020 (and any revised prices for earlier years for new projects) will then be announced up to a year ahead of coming into force as part of the consultation on the cost data and underpinning analysis. Following consultation, the final strike prices will be published in the annual update. At this time the strike prices would be submitted for Parliamentary approval.

Administrative price setting for early stage CCS projects

25. Carbon Capture and Storage will allow fossil fuels to remain a part of the generation mix as the electricity sector is decarbonised. At present, industry experience of putting the technology into practice in large scale power generation is limited, and the potentially high costs and novel risks associated with CCS mean that it is not yet commercially viable. Government intervention is therefore needed in order to bring forward the commercialisation of the technology.

26. On 3 April 2012 the Government launched the new CCS Commercialisation Programme[3], the aim of which is to enable private sector electricity companies to take investment decisions to build CCS-equipped plant, in the 2020s, without

[3] http://www.decc.gov.uk/en/content/cms/emissions/ccs/ukccscomm_prog/ukccscomm_prog.aspx

Government subsidy, and at a price that is competitive with other low-carbon generation technologies. The Programme makes available £1 billion in grant funding, with full chain projects selected through the competition also expected to be able to earn revenue from the sale of electricity supported by CfDs.

27. To secure comparable bids, potential bidders to the competition have been issued with a set of assumptions about the characteristics of the CfD that will be available to successful full chain projects. Some of these assumptions are consistent with the standard CfD terms and conditions proposed in this document. Others represent variations which Government may include within the CfD for early stage CCS projects.

28. For early stage CCS projects (including those supported under the CCS Commercialisation Programme), the level of the strike price will be determined through a process of negotiation between developers and DECC (as part of the CCS Commercialisation Programme competitive process for projects entering that competition and in collaboration with the FID Enabling team as appropriate). The negotiation will be underpinned by an assessment of the costs of producing clean electricity through CCS, taking into account the CCS Programme baseline risk allocation model and a price model.

29. The price setting process for these projects will allow different strike prices to be set for different projects. It is not realistic to attempt to set one strike price for all early stage CCS projects given the wide variety of technologies and location-specific costs projects will involve. Projects that are part of the CCS Commercialisation Programme will also receive direct capital support dependent on their needs, and this will offset revenue they have to earn through the strike price. Furthermore, selecting early stage CCS projects on the basis of strike price alone could prematurely rule out technologies that could prove to be the most viable (technically and economically) in the long run.

30. Flexibility is also needed in the price setting process to effectively manage the uncertainties inherent in early stage CCS projects. CCS is not a commercially proven technology. There is therefore a higher degree of uncertainty, both in terms of the cost of construction (capture, transport and storage) and operational performance and reliability, than for more established generation options. Whilst this uncertainty can be reduced through detailed design, it will only be resolved fully when construction is complete and when the plant’s performance has been fully tested.

31. The Government is therefore considering providing the flexibility to review the strike price after the award of a CfD to CCS projects successful in the competition. Such reviews would take place at the end of construction and again following a limited period of further testing. This revision of the strike price would

be formulaic and the developer incentivised to ensure they were effectively managing costs and reducing risks. The expectation is that reducing uncertainties in this way would secure better value for money than requiring developers to price this uncertainty into project costs, to be recovered through a higher strike price.

32. The inclusion of these variations is subject to further development of the detail of these variations, ongoing analysis of the options informed by more detailed discussions with potential CCS developers and investors, affordability and value for money considerations, and the outcome of discussions with the European Commission on state aid considerations.

Administrative price setting for nuclear projects

33. For nuclear projects the level of the strike price will be determined through an administrative price setting process until the conditions are in place to move to competitive forms of price discovery. To begin with this process will involve negotiation with developers on a project by project basis.

Next steps

34. Once the decisions from the Renewables Obligation banding review have been published, the System Operator will be tasked with reviewing RO banding costs, and assessing what further data gathering is required to support CfD price discovery. The System Operator will carry out its review of costs data over the remainder of 2012, engaging with industry to gather new data as appropriate in the autumn. More detail is set out in the table above.

B. CFD ALLOCATION

The allocation process is designed to give certainty to developers about their ability to obtain CfDs, and to allow Government to manage the costs of the regime. Government's intention is that specified new low-carbon technology plants which are not eligible for the small-scale FIT will be eligible for the CfD scheme. Initially CCS, nuclear and some renewable projects are likely to seek to obtain investment instruments through the CCS Commercialisation Programme or the Final Investment Decision Enabling process.

In the period before auctions or tenders are used to award CfDs, most renewables projects will secure their CfDs through participating in allocation rounds. The design of the allocation process will both support the delivery of the 2020 Renewables Target and enable Government to manage levels of deployment appropriately to ensure the cost effectiveness and durability of the CfD. The process for other low-carbon technologies to secure CfDs beyond the FID Enabling process is still under consideration, and further details will be published in the autumn.

Principles

1. The allocation process aims to maximise low-carbon generation brought forward, whilst being efficient and as straightforward as possible. Therefore it seeks to deliver on the following principles:
    - provide developers with as much certainty as possible over what the market opportunity looks like for low-carbon technologies, allowing them to plan their projects and giving Government visibility of how much generation is being developed;
    - preserve the ability to respond flexibly to ensure that inappropriate levels of support are avoided, mitigating the risk of under- or over-deployment; and
    - provide value for money and minimise costs to consumers (ensuring CfD costs are affordable).

Eligibility

2. The intention is that any new low-carbon generation plant which is not eligible for a small-scale FIT will be eligible to apply for a CfD. Government will also consider any developments with the small-scale FIT in future when making decisions whether to extend eligibility.

3. The starting point for eligible renewable technologies is those listed in the Renewables Directive. Article 2(a) of the Renewables Directive (2009/28/EC) sets out that "'energy from renewable sources' means energy from renewable non-fossil sources, namely wind, solar, aerothermal, geothermal, hydrothermal and ocean energy, hydropower, biomass, landfill gas, sewage treatment plant gas and biogases;[4]" However, not all of these are yet economically viable at scale for electricity generation, so the plan is to broadly reflect current practice under the Renewables Obligation.

4. A comprehensive list of technologies eligible for support will be provided in secondary legislation. Those eligible under the RO are expected to be included, in addition to nuclear and CCS-equipped plant, which together are likely to deliver the majority of decarbonisation necessary to meet Government targets. It will be possible to add additional low-carbon generation technologies to this list where either a new technology emerges, or an existing technology which is not initially deemed eligible is felt to have the potential to make a significant, desired contribution to decarbonisation and the generation mix if offered support.

5. The Government realises that large-scale fossil fuel combined heat and power (CHP) plants that export electricity to the grid will face challenges following the removal of their exemption from the Climate Change Levy. The evidence for future support for fossil fuel CHP is currently being assessed, by considering the barriers and market failures facing fossil fuel CHP; and appropriate policy options for addressing these (including through Electricity Market Reform). Government will continue to work with industry including the Distributed Energy Contact Group and the CHP Association (CHPA) as thinking is developed on this issue.

Enabling final investment decisions required in advance of implementation of the CfD regime

6. As set out in last year's White Paper and subsequent Technical Update[5], the Government recognises that the changes to the market proposed under EMR could lead to some investment decisions being delayed, and is committed to working with relevant developers to enable early investment decisions, including those required ahead of EMR implementation, to progress to timetable wherever possible. The Final Investment Decision (FID) Enabling work intends to allow FIDs to progress that would otherwise have been delayed until all necessary legislation had been enacted and new institutional arrangements put in place.

[4] http://eur-lex.europa.eu/LexUriServ/LexUriServ.do?uri=OJ:L:2009:140:0016:0062:en:PDF
[5] http://www.decc.gov.uk/assets/decc/11/meeting-energy-demand/energy-markets/3884-planning-electric-future-technical-update.pdf

7. To deliver this commitment, DECC will enter into discussions with developers of projects that exhibit the characteristics that were set out in the Technical Update with a view to considering what form of comfort (subject to any state aid decisions) might be given to support the taking of FIDs. Government recognises that for some investors and developers, early and robust certainty on key aspects of the revenue support that will be available (such as the strike price and length of support) will be key in enabling final investment decisions to be made in a timely manner. It also recognises the need to ensure that the FID Enabling process is capable of enabling different types of low-carbon electricity generation projects which may have different investment and economic issues and considerations attached to them. At this point, it is not possible to know all the projects that may come forward nor, in advance of engaging with the relevant investors and developers, know all the project-specific issues that an enabling product might need to address.

8. Among the options available to the Government to give comfort to developers is the option for the Secretary of State to issue investment instruments (which will be similar to CfDs) in advance of the EMR CfD regime being implemented (subject among other things to the necessary powers being included in the legislation – see 'Investment Instruments' provisions set out in the Draft Energy Bill – and any necessary state aid decisions being made). The actual option (or enabling product or enabling arrangement) that might be offered in relation to projects will depend on the projects that come forward for the FID Enabling process and the outcome of any such engagement.

9. As stated in the Technical Update, any eventual offering by the Government will be considered on a case by case basis, but will so far as may be appropriate be as consistent as possible between different potential applicants, as well as complying with Government policy generally, and with the generic aspects of Electricity Market Reform. Any such offering will also need to be compliant with domestic law and be subject to the Government's obligations under EU law, including the terms of any necessary state aid approvals.

10. However, developers should note that even if DECC agrees that a project has the required characteristics and engages with the relevant developer to discuss the enabling product or arrangement that might be offered, this should not be treated as an indication that the Government will offer any assurance in relation to that project or that DECC will continue discussions with the developer. The final decisions on offering any form of comfort to developers will rest with Ministers. Any enabling product or arrangement offered to investors or developers would have to be clear value for money for consumers and affordable.

11. A number of developers (including new nuclear and early stage CCS developers) have expressed interest in the FID Enabling process to date and it is possible

that other developers may also do so. Where the option to issue investment instruments is utilised in relation to an individual project, the FID Enabling process is likely to be the route for setting the strike price for that project (for example in the case of new nuclear projects requiring FIDs in advance of EMR implementation) or contribute to the setting of the strike price for that project (for example in the case of early stage CCS projects requiring FIDs in advance of EMR implementation but which are participating in the UK CCS Commercialisation Programme).

Transition from the Renewables Obligation

12. Large-scale renewable electricity is currently supported by the Renewables Obligation (RO). The RO and small-scale Feed-in Tariff have driven renewable electricity deployment from 3GW in 2002 to 12GW in 2011, and have encouraged new renewable technologies to evolve, such as wave and tidal. Throughout the EMR process, Government has recognised the need for a clear and stable transition period from the RO to the new support mechanism of the CfD, in order to prevent a hiatus in renewables investment. Full details of the transition proposals were set out in the EMR White Paper and Technical Update.

13. The aim of the transition proposals is to ensure that, throughout the time when new arrangements are being introduced, investors should always be able to make an investment decision on the basis of a known income stream, if they choose to do so. The UK Government has responsibility for the RO in England and Wales, and is working with the NI Executive and Scottish Government to ensure a coordinated transition. Therefore, the RO will remain open across the UK to new accreditation until 31 March 2017. CfDs will be available from 2014 in GB, and from that date until March 2017, new generation will be able to choose between the Renewables Obligation (RO) and the CfD in GB. The NI Executive does not expect CfDs to be available earlier than 2016 in Northern Ireland; the UK Government is working with the NI Executive regarding how best to provide early visibility of strike prices for generation in Northern Ireland.

14. The transition arrangements provide the following options for renewables generators:
    - Generation which is able to commission before 31 March 2017 will be eligible to accredit under the RO, and could therefore take an investment decision on the basis of receiving the RO.
    - CfDs will be signed on allocation, subject to financial close; therefore any project reaching financial close from mid-2014 would be able to apply for a CfD, and take an investment decision on that basis.
    - Any projects which need to make a final investment decision before full details of the CfD are available, but which may not be able to commission

in time to accredit under the RO, are invited to discuss their needs with the DECC Final Investment Decision Enabling Project.

15. Once the RO is closed to new generation on 1 April 2017, all projects receiving RO support will continue to do so (subject to the maximum 20 years' support and 2037 end date for the RO). New renewable generation will be able to apply for a CfD. To provide further certainty, limited grace periods will be offered, aimed at generators whose investment decision has been based on support under the RO, but whose accreditation is delayed beyond 31 March 2017 by factors beyond their control. These could include a delay in network connection instigated by the transmission or distribution operator, or a delay in radar installation. In addition to this, for offshore wind developers who have chosen to 'phase' their generation under the RO, it will be possible to phase across both support schemes – with some phases under the RO, and remaining phases under a CfD.

Allocation of CfDs for renewable projects under administrative price setting

16. The price setting process described in section A will result in strike prices being set for each year from 2014-2018. These prices are likely to differ by technology and by year, so that a project commissioning in 2017 may receive a different strike price than if it had commissioned in 2016.

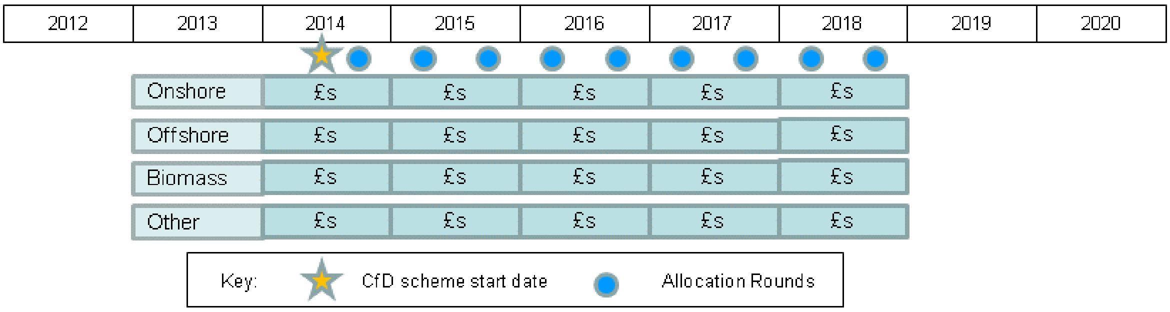
17. Government is minded to allow developers to apply for a CfD immediately before Financial Close. Consequently, a project which secures a CfD can be certain about the revenue it will receive much earlier than it would do if supported under the Renewables Obligation. While 'Financial Close' is not a precisely defined term, for project financed plant Government is minded that it will be the point at which the banks or equivalent organisations commit to financing the project, subject only to the award of the CfD (i.e. loan agreement is ready for signature). For on-balance sheet funded projects, Financial Close will be less easy to evidence precisely. The Government is currently considering whether it will be necessary to set specific criteria for equity plant of each technology type. In any event developers are likely to have to provide proof of substantive commitment of resource to the project e.g. board papers approving expenditure. All projects as part of their milestones will be required to provide evidence of contracts e.g. for turbines and construction works within a given time period after Financial Close.

18. The Government is minded that the allocation system should be designed to monitor and potentially control the number / volume of projects receiving CfDs for each year. It should provide Government with a means to assess whether higher or lower than anticipated rates of deployment suggest a technology has been

mispriced. Regular allocation rounds will be used to enable developers to bring forward their projects.

19. Therefore the proposal is that the System Operator will run allocation rounds every six months e.g. April and October. Each round is expected to take about three months, with the application window open for a month, the System Operator carrying out an assessment of applications against criteria and then awarding CfDs to successful projects by the award date marking the end of the allocation round.

Figure 5: Strike prices published for a five year period



20. At the start of an allocation round the System Operator will publish the following information:
    - Confirmation of the eligible technologies.
    - The term (i.e. length) of the CfDs being offered for each of the technologies.
    - The Strike Prices available for each technology and each year in that round (as set out in the delivery plan or annual update).
    - Further detail on the application process.
    - Conditions for the award of the CfD.
    - Other Implementation terms (such as compatibility with sustainability requirements).

21. Before being allowed to enter an allocation round, the Government is minded that developers will be required to provide information, including:

Table 4: Application Content

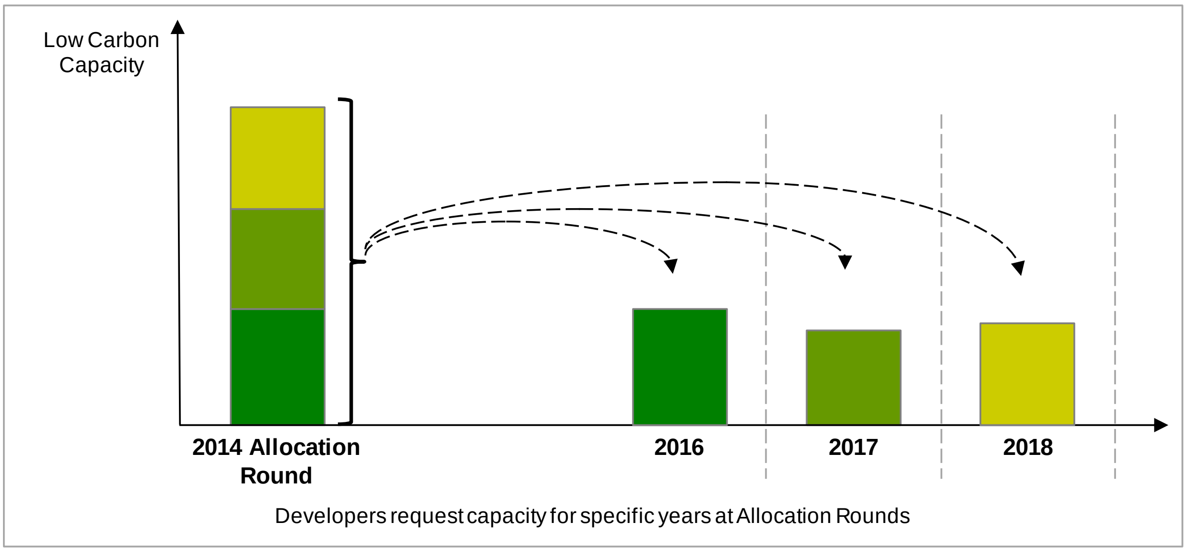
Category	Information
Company Details	Company Registration, VAT Number and brief description of company etc.
Applicant Role	The capacity in which the Applicant is pursuing the project (Developer / Commercial Operator / Both).
Project Description	Including Project Type (new build / conversion / re-powering), Technology, Capacity, Design Plant Life, Expected Load Factor, Fuel (if relevant) etc.

Proof of Planning Permission	Confirmation of Planning Permission decision notice.
Expected Commissioning	Target Commissioning Date.
Estimated Financial Close	Designation of likely date for Financial Close for project financed plant and equivalent commitment for equity plant (with indication of proof of commitment to be put forward).
Proof of relevant Crown Estate lease	Only relevant in the context of offshore wind or marine projects.

22. The Government will consider whether the System Operator should carry out more in-depth due diligence such as checking the project sponsor, history of delivering projects, financing etc at this point. In the case of biomass projects there is likely to be a process of confirmation (e.g. use of an eligible sustainable fuel type) prior to any payments flowing under a CfD.

23. Once the allocation window closes the System Operator will allocate CfDs and agree timescales for commissioning. At this point developers who are successful will have a CfD with a fixed strike price, subject to commissioning within an agreed target commissioning period.

Figure 6: Developers request capacity for specific years at allocation rounds



Allocation of CfDs under a competitive process

24. At the point of transition to competitive processes, allocation and price setting processes essentially merge. Design of competitive processes such as a tender or auction is an intricate activity which is highly sensitive to the market conditions

in which it is to operate. Given that conditions are not expected to be right for such processes until 2017 for some renewable technologies, it is not appropriate to focus on the detailed design yet. However work is ongoing on the key principles of design and how other considerations (such as security of supply) can be incorporated.

25. The System Operator will continue to administer the allocation of CfDs under a competitive process and will consequently be closely involved in design. Any move to competition will be clearly signalled by Government through the delivery plan or annual updates. Further details will be provided in the Operational Framework this autumn, and industry will be involved in developing this approach over the course of the summer, including through the CfD Expert Group, interaction with trade associations, and bilateral meetings.

Management of Financial Exposure

26. Like all other aspects of Government policy, EMR has to operate within affordability constraints. The Government will therefore have to prioritise within and between policies, whilst still delivering on statutory renewable and decarbonisation targets and other core objectives. Where strike prices for individual, early nuclear, CCS and renewables projects are set through a bespoke negotiation process (such as the process proposed for projects seeking to make final investment decisions in advance of the CfD regime and the bespoke process that may apply for some projects after that regime is implemented), Ministers will ultimately take a decision on whether those strike prices are value for money and affordable and determine whether or not to award the CfD in light of that analysis.

27. For renewables, where the number of projects is far greater, it is not necessary or practical to have bespoke negotiations. Therefore strike prices will be set administratively for most renewables projects. The Government aims to avoid disrupting developers and supply chains, which might occur if published strike prices were rapidly revisited or if the supply of CfDs were suddenly curtailed. The Government has therefore given clear visibility of the level of deployment ambition for renewables projects in the Renewables Roadmap[6] and wants to ensure that developers have the confidence to deliver against the stretching renewables targets, while Government is able to protect consumers by retaining appropriate control over the costs of decarbonisation.

28. The Government is minded to instruct the System Operator to only issue CfDs for low-carbon generation up to the value of the amount set out in the Levy Control

[6] http://www.decc.gov.uk/en/content/cms/meeting_energy/renewable_ener/re_roadmap/re_roadmap.aspx

Framework. The same principle will also apply when the Secretary of State is issuing any investment instruments in relation to projects that require final investment decisions in advance of EMR implementation, and when issuing any CfDs after the CfD regulations come into force.

29. The administrative price setting process for renewables limits deployment to those projects which can come forward at a given strike price. As with current provisions for 'emergency review' under the Renewables Obligation, the process for setting CfD strike prices beyond 2018 can be used to review prices for technologies where unexpected cost changes or rates of deployment have occurred. Government is committed to the principle of grandfathering commitments, therefore any process would not alter strike prices of CfDs already issued, which would remain fixed (barring any adjustments within the terms of the CfD e.g. for inflation). However, there may be a case for enabling more fine-grained control of cost without running a full price setting process or carrying out an emergency price review which can be disruptive to investors and supply chains. Three options are being considered, and in each case it is anticipated that any additional control will be applied in a manner which allows the achievement of the 2020 Renewables Target.

Control by price setting, with additional controls for particular renewable technologies

30. The first option would be to set an overall cost envelope for each of nuclear, CCS and renewables. As set out above, costs for nuclear and CCS projects would initially be managed through a negotiation process. For renewables, in addition to the overall envelope there would be controls for specific technologies where there is judged to be risk of significant over- or under-deployment, or rapid cost changes. The aim would be to set degrees of control in accordance with how responsive it is felt the system needs to be in respect of a specific technology. For example, the system would need to be more sensitive to technologies with the possibility of rapid deployment or cost changes such as biomass conversions and solar PV. Such technologies may only be given one or two years' advance visibility of strike prices, which would allow finer control of deployment. Alternatively – or in addition – these technologies might be required to pre-accredit. In the event that the amount of potential capacity seeking pre-accreditation reached a set trigger level, Government would reserve the right to change the strike price for subsequent allocation rounds for generation which had not yet been awarded a CfD. This approach does require additional administration, and offers less long term price visibility for controlled technologies. However, this approach has the benefit of providing finer control in the case of technologies which pose a greater risk of over- or under-deployment.

Specific volume targets for each technology (including individual renewable technologies)

31. The second option would be to introduce technology-specific targets. For nuclear and CCS this would initially be managed through a negotiation process. For renewables, targets would be informed by Government aspirations set out in the Renewables Roadmap and delivered through the allocation rounds. Any unused capacity in a given year could be rolled over to subsequent years. The mechanism by which any unused capacity would be reallocated has yet to be determined, and could be informed by updated evidence on the potential and prices for different technologies available in the future.

32. This approach would allow a degree of fine control and would also give industry a very clear indication of Government aspirations. However, the Government does not currently set annual technology-specific aspirations, and it may be challenging to do so accurately, and in a way that does not artificially constrain deployment. There is also some concern that this level of market direction could dampen supply chain development.

Control by price setting alone

33. Under the third option, costs would be controlled by reviewing the strike prices set for technologies and amending them for future projects in the event that technology costs, deployment or projects seeking CfDs were significantly greater or less than expected. For nuclear and CCS this would initially be through individual negotiations, for renewables through amending the administratively-set strike prices for future projects. The total amount of money available for a five year period would be announced, and the System Operator allowed to issue CfDs until it was expended.

34. There are a number of issues with this approach. Under this option Government is not explicitly setting the renewable technology mix, but the finite level of total support means that if there was more deployment of one renewable technology than expected, it could be at the expense of deployment in another renewable technology. This option depends on a review to amend the strike price to avoid over- or under-deployment, and this response would be relatively slow. In addition, the Government could not guarantee the timetable for future renewable allocation rounds in case all money was committed early.

Next steps

35. Government will continue to engage with industry, the System Operator and others to further develop the proposals around managing financial exposure over

the summer. A decision on which mechanism is most appropriate will be made prior to issuing the final CfD Operational Framework in autumn 2012.

C. CFD TERMS – PRE COMMISSIONING

The Government is minded that the CfD should contain pre-commissioning terms which place obligations on developers to ensure that projects are built to agreed timescales. The Government is further minded that proportionate penalties should be available to incentivise compliance with these obligations.

Principles

1. It is necessary to place obligations (within the CfD) on CfD-supported projects to provide information on build progress to the System Operator; and to construct and commission the agreed size and type of low-carbon plant within agreed timescales. It is also necessary to apply proportionate penalties in the event of non-compliance. This is required for a number of reasons, including to:
    - enable the effective management of the costs of the scheme (including enabling suppliers to plan their customer tariffs);
    - enable a meaningful assessment of progress towards renewable energy targets as well as the overall rate of decarbonisation;
    - ensure that commitment to support is not tied up in projects which fail to get built, potentially at the expense of other viable projects; and
    - avoid potential manipulation of the allocation system.

2. The Government recognises that project developers are in the main already subject to strong commercial incentives to avoid delay or abandonment and will take this factor into account in shaping obligations. The Government is also minded to ensure that monitoring processes are, whilst meaningful, not unduly onerous, and avoid unnecessary duplication with existing Grid Code (and distribution network equivalent) compliance processes.

Milestones

3. The Government is minded that developers must provide the System Operator with a schedule of key Construction Milestones as part of their application to receive a CfD. These milestones should be consistent with those in the developer's construction agreement with the System Operator, but as a minimum are likely to include:

Table 5: Milestones

Category	Information
Environmental Consents post Planning Permission	Environmental consents and other approvals (if any) required prior to construction start (in addition to Planning Permission), but not obtained at the time of the Application.
Financial Close / Final Commitment	The anticipated timing of Financial Close for project financing and final commitment for projects founded on the balance sheet.
EPC Signed or equivalent commitment	Signature of EPC contract or nearest equivalent where construction is carried out in-house.
Ground works started	The date at which ground works are commenced at the site. For the avoidance of doubt this includes the initial site clearing where relevant.
Connection Agreements in Place	The date of the relevant Grid or Distribution Connection Agreement is signed (subject to System Operator Acceptance Testing).
Turbine / Generation Engine Installed	The date at which the turbine (or some proportion of overall capacity which is to be determined) or, where relevant, the generation engine is installed.
Commissioning Acceptance Tests Scheduled	The date at which National Grid Commissioning Acceptance Tests have been scheduled under the Grid Code or, in the case of small scale plant, scheduling of similar tests with the local Distribution Network Operator.
Expected Commissioning Date	The date at which the project expects to complete Commissioning Acceptance Testing and become fully operational.

4. Only milestones agreed with the System Operator will be regarded as binding. The Government will require the System Operator to monitor achievement of the milestones submitted by projects which have received CfDs.

Delivery incentives / non-delivery penalties

5. Whilst developers have firm incentives to deliver on time, imposed on them by their financing agreements and build contracts, very precise project delivery dates are unlikely to be achievable. Government is therefore minded to allow projects to commission within a defined ‘target commissioning window’ time period before or after their target commissioning date without facing any penalties under the CfD (subject to paragraph 7 below).

6. In order to encourage developers to provide as accurate a forecast of their target commissioning date as possible, projects that commission ahead of their specified target commissioning window will be able to operate commercially and sell their power, but will not receive or make CfD payments until the start of that target commissioning window. After that point they will receive or make payments under the CfD as normal.

7. Due to the reasons outlined above, the Government is minded that it is appropriate to provide for a penalty to apply when CfD supported projects commission late. Such a penalty may be triggered by failure to commission within a target commissioning window. Government is further minded that the penalty imposed would be a reduction in the agreed term of the CfD commensurate with the length of any delay beyond this point.

8. However, the Government is still considering alternative and possibly additional options. These might include a reduction in the agreed CfD strike price, or (similar to the arrangements for the Danish offshore wind tender) imposition of financial penalties for delay or abandonment, with developers required to provide collateral to cover those penalties.

9. The Government is clear that any delivery incentives should be proportionate, and will discuss these issues further with stakeholders prior to reaching a final decision. Furthermore, there will be engagement with industry to determine the appropriate length for target commissioning windows including whether and how best to differentiate between technologies, for example on the basis of standard build times.

CfD parameters determined subsequent to award

10. Two parameters within the CfD depend on the actual time at which the plant passes the Commissioning Acceptance Tests. These parameters are:
    - **The Payment Start Date:** The Payment Start Date will be the actual date at which the project passes the Commissioning Acceptance Tests, unless this occurs before the beginning of the Target Commissioning Window. On such occasions the Payment Start Date will be deemed to be the start of the Target Commissioning Window. The Government will, working with the System Operator, give further consideration to the precise arrangements to apply in relation to projects which commission in phases.
    - **Adjustments to CfD length:** The length of the payment period of the CfD may be reduced if the plant fails to commission within the allowable Target Commissioning Window.

Commissioning Acceptance Tests

11. In order for payments to be made under the CfD, the Government is minded that plant will first have to pass the Commissioning Acceptance Tests stipulated in the issued CfD. For the purpose of the CfD, these tests include:
    - for all plants which are subject to the Grid Code regulations[7] (the current threshold is around 10MW), completion of Commissioning Acceptance Tests required under the Grid Code;
    - completion of the Commissioning Acceptance Tests set out by the relevant Distribution Network Operator for plants which fall below the Grid Code threshold; and
    - (possibly) any further tests that may be required to establish that the plant meets the specifications for which the CfD was awarded as set out by the System Operator in the allocation rounds or through the FID Enabling process or CCS competition.

12. The first two requirements above reflect the tests that any plant in the system must pass in order to be allowed to deliver power to the transmission network or, for embedded generation, the relevant distribution network. These tests are primarily concerned with ensuring operationally safe dispatch and the system's ability to absorb faults.

13. The Government is minded that, for some technologies, additional tests are likely to be required, for example to verify that the sustainability and carbon content of the fuel used by a biomass plant is in accordance with the basis on which the developer was awarded the CfD, or that the carbon dioxide captured by a CCS-equipped plant has been or will be permanently stored.

14. In relation to early stage CCS projects, the Government is also mindful of the need to ensure that the arrangements for Commissioning Acceptance Tests and any associated penalties take account of, and are appropriate given the additional period of testing expected to be required for CCS-equipped plants (see 'Administrative price setting for early stage CCS projects' section above).

[7] http://www.nationalgrid.com/uk/Electricity/Codes/gridcode/

D. CFD TERMS – POST COMMISSIONING

This section sets out the Government's emerging proposals on those CfD terms that apply to the post-commissioning phase***.*** These terms will define a number of arrangements required to ensure that the CfD functions effectively, including:

- how CfD payments are calculated;
- how often CfD payments are made;
- how long the CfD endures; and
- how terms may be adjusted over time.

To provide as much clarity as possible on these emerging proposals, where appropriate, this section provides a technical translation of the policy to give a greater indication of what the actual CfD terms might look like in practice.

Table 6: Terms covered in this section (and the following section on Settlement)

Term	Description	Emerging Proposal
Reference Price	The market price for electricity that is referenced in the CfD for the purpose of calculating CfD payments.	Intermittent: Hourly Day Ahead Auction Price for the GB Zone (as established under North West European Market Coupling). Baseload: Year Ahead, price source to be determined.
CfD Volume	The definition of the volume of electricity for the purpose of calculating CfD payments, and the resulting metering requirements.	Minded to pay the CfD on the basis of metered output unless the price in the reference market is negative, in which case to pay on a measure of availability.
Allocation of supplier payments	How suppliers' payment obligations / entitlements are calculated.	Minded to base suppliers' payment obligations on market share, as defined by 'supplier cap take'.
Settlement	Process and timing for invoicing and administering CfD payments.	Minded to base processes on Balancing and Settlement Code processes. Minded that settlement periods will be at most one month.

CfD Length	The length of the CfD from the payment start date as defined in section C.	Initial view that CfD length for renewables should be 15 years. 10 years (subject to negotiations) for early stage CCS project(s) supported under CCS Commercialisation Programme. Nuclear and long-term CCS-equipped plant to be determined.
Inflation indexation	Arrangements for adjusting the CfD strike price in line with inflation.	Minded to choose CPI as a standardised and established inflation measure that is familiar to international institutional investors.
Fuel Price indexation	Arrangements for adjusting the CfD in order that payments reflect a generator's input fuel costs.	Minded not to link the CfD strike price to fuel costs for biomass. For the first CCS project(s), minded that the CfD should provide indexation needed to hedge against long term fuel price variability.
Credit and Collateral	The requirements on generators and suppliers to provide credit / collateral.	Minded to place a collateral requirement based on an estimate of likely settlement amounts due in a given trading (settlement) period.
Amendment of the reference price and other CfD parameters	The arrangements for amending CfD parameters (such as the reference price or other variable definitions) in response to changes in trading arrangements which change or render variable definitions invalid, or changes in market liquidity or trading platforms which might impact the validity of the indices used to calculated the reference price.	Minded to include an 'independent expert' role in the CfD framework to manage any review of CfD parameters and determine any amendments required.

Change in Law	Arrangements for adjusting the CfD in response to relevant changes (e.g. regulatory) that materially affect the value of the CfD to either party.	Minded in principle that the CfD should contain change in law provisions, the form and scope of which remain to be determined. Further detail will be set out in the autumn.
Dispute Resolution	Procedures for resolving any disputes arising under the CfD.	The Government will seek further legal advice in this area before engaging with stakeholders later in the year.

Principles

1. Overall, the aim is to deliver CfD terms that are largely standardised across technologies. This provides a stable basis for investment and makes it easier to compare costs of different technologies. It is consistent with the Government's long term plan to deliver least cost decarbonisation by providing a framework in which technologies compete for CfDs. Notwithstanding this, the EMR White Paper set out the intention to develop different CfDs for intermittent and baseload plant given their different characteristics. Government's view is that the CfD can be applied to all types of low-carbon generation, regardless of whether certain technologies – such as tidal power – may not fit neatly within the definitions of 'intermittent' or 'baseload'.

2. In the short term, moreover, there may need to be provision for some variation in CfDs for certain technologies – within intermittent and baseload classes – in recognition of their different risk profiles (for example early stage CCS projects, due to their demonstration status), to ensure that they come forward at a reasonable cost. That said, risk should remain with the party best placed to take it, and it must be clear that any variations offer value for money and are consistent with securing state aid clearance.

3. The proposals outlined below are still being refined, and different aspects of the proposed design are at different stages of development. The Government will continue to engage with Ofgem, industry and other stakeholders in order to further develop these proposals prior to issuing a final CfD Operational Framework in the autumn.

4. Unless otherwise indicated, the text below applies to both the intermittent and the baseload CfD. In many cases, the text also applies exclusively to the GB Market. The Government continues to discuss the development of the CfD with the Northern Ireland Executive in respect of participants in the Single Electricity Market, with a view to extending the proposed arrangements to Northern Ireland.

CfDs for flexible plant

5. With a view to meeting the Government's objective to largely decarbonise the electricity sector, the intermittent and baseload CfDs incentivise low-carbon plant to operate at high load factors. However, the Government acknowledged in the EMR White Paper that in future, a different structure of CfD may be required to bring forward investment in flexible low-carbon plant that would be incentivised to increase and decrease their output in line with shifts in demand and to offset the intermittency of some renewables. At this stage Government remains minded that, given the continued role likely to be played by conventional gas-fired generation, a CfD for flexible plant may not need to be issued during this decade. This will be kept under review, and more detail on a potential CfD for flexible plant will be set out in due course.

i. Reference Price

1. CfD payments are based on the difference between the reference price and the strike price. In Great Britain, electricity can be bought and sold on different trading platforms, in different volumes and at different periods of time before it is actually delivered. The reference price is therefore only a representation of the actual market price achieved by a generator, although the two can be the same. It is used to calculate CfD payments to be made to or received from low-carbon generators.

Intermittent generation

2. For intermittent generation, the EMR White Paper confirmed the preference that the day ahead market should be the market segment from which the reference price is drawn. More specifically, the White Paper suggested that the Reference Price for intermittent CfDs would:
    - reflect a basket of exchange-based (e.g. APX, N2Ex[8]) and OTC[9] price indices, with an 'independent expert' appointed to review and change the weights in the basket as and when required; and
    - be expressed as a baseload day ahead price (as opposed to hourly day ahead prices) in part because the available OTC indices (such as LEBA[10]) adopt this product definition.

3. The two principal reasons for initially adopting this position were the absence of a dominant platform for day ahead trading coupled with the prevalence of OTC based trading; and concerns about the ability to manipulate a (thin) single index[11]. Since the White Paper, analysis of various GB day ahead indices has been carried out, and developments in wholesale market liquidity and the broader market monitored. Government is therefore minded to revise the initial position in light of a number of developments, namely:
    - the planned implementation of Market Coupling arrangements for the North Western Europe (NWE) region in late 2012/early 2013;
    - the creation of a 'GB Hub' for day ahead trading to support this initiative; and
    - the significant growth in exchange-based Day Ahead (DA) trading in the GB market.

4. The market coupling arrangements for the NWE region form part of a wider roadmap for the integration of European wholesale power markets. In simple

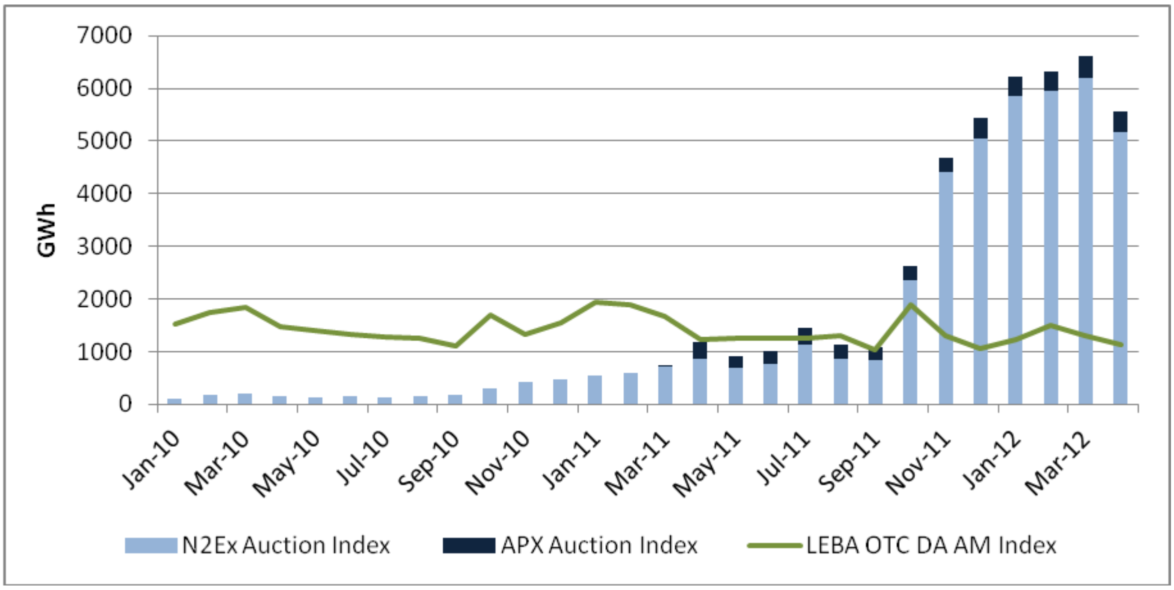
[8] Great Britain's two power exchanges.
[9] Over-the-Counter (or off exchange) trading, where electricity is traded directly between two parties
[10] The London Energy Brokers Association, which produces electricity price indices
[11] Trading in a way which causes or maintains an artificially low or high price

terms this requires participating countries to use a common approach to calculating a day ahead price for electricity which implicitly includes the price for accessing interconnector (transmission) capacity between different countries. The intention is to achieve optimal use of those interconnectors, and the creation of an integrated European energy market. This means that physical flows of electricity between individual countries should reflect price signals (i.e. electricity should flow from a market with lower prices to a neighbouring market where the price is higher).

5. For GB to participate effectively in this project, a single 'GB Price Zone' needs to be created, which will contain the orders of the two GB power exchanges (currently APX and N2Ex). National Grid is in the process of establishing a 'GB Hub' which will pool the bids and offers from the power exchanges and, as part of the wider NWE coupling arrangements, calculate a single 'GB Zone Price' for each hour. To enable this, the power exchanges will need to offer compatible day ahead auction products and participate in the NWE market coupling auction processes. In other words, whilst both exchanges will continue to operate independently, their participation in the NWE process via the GB hub will produce a single GB Zone price.

6. The Market Coupling arrangements for the NWE region are scheduled for implementation in early 2013 with the Single Electricity Market (Republic of Ireland and Northern Ireland) joining by, at latest, 2016.

Figure 7: Auction and LEBA day ahead volumes



7. As the above chart shows, there has also been significant growth in the volumes of electricity traded through exchanges, specifically through day ahead auctions. Exchange based day ahead trading has increased by more than 500% since the

EMR White Paper, and at the time of writing represents around 20% of GB generation.

8. The Government's view is that whilst trading patterns could change, there are a number of factors which may help solidify this recent growth in trading, including:
    - continued domestic regulatory pressures to ensure a liquid wholesale market;
    - European regulations which increase the cost of bilateral trading;
    - the need for market participants to trade through these exchanges in order to access the interconnectors and the NWE market; and
    - the possibility of a 'virtuous cycle' of liquidity generation as a clear day ahead price reference emerges (reinforced by increasing volumes from intermittent CfD generation).

9. The Government is therefore now minded that the reference price for the intermittent CfD should be the hourly day ahead GB Zone price. As Northern Ireland, via the SEM, will have joined by that stage this reference price should also apply in Northern Ireland. In the meantime DECC continues to work with the Northern Ireland Executive to discuss an appropriate reference price for the Single Electricity Market should Northern Ireland join the CfD scheme earlier than 2016. Our initial view is that, in this eventuality, the combined System Marginal Price and Capacity Payment may provide a suitable reference price for the intermittent CfD.

10. For the reasons outlined above, the GB Zone Price is likely to provide the most credible, robust and enduring index. In addition, it will significantly increase revenue certainty and stability for intermittent generators, who will be able to trade the reference price (i.e. removing basis risk[12]) by participating in either the APX or N2Ex day ahead auction, and will be far better able to capture an hourly price than a baseload price, as they will be able to trade more in line with their forecast output.

11. It is acknowledged that smaller generators will in many cases not be able to participate directly in either exchange. Section F of this document outlines the Government's views on the impact of the CfD on generators accessing the electricity market through an off-taker, noting that the CfD offers the potential for Power Purchase Agreements to be simpler, more transparent and potentially offer better terms, mainly due to the simplification of risk management under the CfD.

[12] Intermittent generators will still have to manage forecasting risk and will still be required to manage their output onto the system.

12. The Government recognises that market coupling is an ongoing initiative which has not yet been implemented. Whilst there is reasonable confidence that the single GB Zone day ahead reference price will be established in time for the issue of the first CfDs in 2014, it is necessary to consider a fallback position.

13. Should market coupling arrangements not be implemented as planned, a likely fallback option would be to apply a (volume weighted) average of the hourly prices from each day ahead auction conducted by the GB power exchanges (currently APX and N2Ex). This would introduce some basis risk but at current levels of liquidity would still represent a robust CfD reference price and moreover as an hourly price it would be preferable to the previously envisaged baseload alternative. This could also be a likely fallback option should market coupling arrangements be delayed, possibly as an interim measure to enable market participants to become familiar with the new (market coupling) arrangements.

Baseload generation

14. For baseload generation, the EMR White Paper set out the preference that the year ahead market should be the market segment from which the reference price is drawn. The reasons for this preference were:
    - year ahead prices effectively represent an average of market prices across the year of delivery, and averaging prices to derive the reference price sends a strong signal to baseload generation to carry out maintenance when market prices are low and ensure it is operating when prices are high;
    - a year ahead reference price places an incentive on baseload generators to sell ahead of delivery, which in turn retains a commercial incentive for reliability[13], and also allows suppliers to meet the needs of their customers who are looking for longer term stability; and
    - using a forward market should help to enhance liquidity in that market, which may have benefits for small or independent suppliers.

15. For these reasons, Government remains minded to use the year ahead market. Given the anticipated changes in GB market liquidity due to ongoing Ofgem initiatives, indicating the precise source of prices, based on current price publications, in detail today would not be useful.

16. Ofgem's most recent consultation on enhancing liquidity in the wholesale electricity market[14] highlights a lack of liquidity in 'products further along the curve, such as those beyond a month out'. The consultation proposes 'focussing

[13] This is not to imply that technical reliability is a function of contracting. However the same incentive does not apply to intermittent generation due to its inability to control the timing or volume of its output.

[14] http://www.ofgem.gov.uk/Markets/RetMkts/rmr/Documents1/Liquidity%20Feb%20Condoc.pdf

on the development and delivery of a Mandatory Auction selling key longer-dated products'. This would involve regular auctions with a requirement on obligated parties to sell specific products, 'with sufficient volume in each product to potentially meet demand and produce robust prices'.

17. Subject to decisions by the Gas and Electricity Markets Authority later this year on the development of the Ofgem Mandatory Auction proposal, and on a modification of the licence, the Mandatory Auction could be a strong candidate for the reference price source for the baseload CfD.

18. In the absence of a Mandatory Auction, the Government remains minded that the reference price would be calculated as the average of the Summer & Winter EFA[15] baseload contracts calculated each business day in the year (April-March) for the following year's delivery based on OTC, Market Assessments and Exchange Transactions. Season ahead remains the longest contract with adequate liquidity, although the Government notes that calendar contracts are now quoted more often.

19. A more technical translation of these emerging proposals, to give a greater indication of what the actual CfD terms might look like, is set out in Box 1.

Box 1: illustrative terms for the CfD reference price

Intermittent

GB Market Reference Price under NWE Market Coupling

The Market Reference Price for GB located CfD plant shall be the hourly day ahead auction price as determined by the NWE price coupling algorithm for the GB Price Zone for delivery the following day:

F1 $MRP_t = DAP\_GB_{t,(BD-1)}$

Where:

$DAP\_GB_{t(BD-1)}$ Is the GB Day Ahead hourly price applicable to Settlement Period (t) as determined under the EU price coupling algorithm for the GB Price Zone.

GB Market Reference Price in the absence of NWE Market Coupling

In the event that NWE Market Coupling arrangements are delayed, not implemented as planned, or for any other reason the GB Day Ahead Price is not available, the Market Reference Price will be calculated as follows:

[15] Electricity Forward Agreement.

F2 $MRPt = \sum_e(DAP_{e,t} * DAV_{e,t}/\sum_e DAV_{e,t})$

Where:

$DAP_{e,t}$ Is the Day Ahead price for delivery on the following day in settlement period t (a particular hour) as determined in the auction conducted by GB exchange e;

$DAV_{e,t}$ Is the gross volume transacted in the auction conducted by GB exchange e for Settlement period t on the following day; and

$\sum_e DAV_{e,t}$ Is the sum of gross volumes traded for delivery the following day in Settlement Period t in the auctions conducted by all GB exchanges.

Baseload

GB Market Reference Price

The Market Reference Price for Baseload CfDs shall be set in advance of each year and calculated as the average of Summer and Winter Baseload EFA contracts quoted daily in the preceding year. For example, the MRP for 2013/14 (April 2013 to March 2014) is the average of daily quotes in the preceding year (2012/13) for (delivery in) Summer 2013 and Winter 2013/14 for each index from which quotes have been sourced.

In the event that it is determined that price quotes should be obtained from a single source (Price Index), the MRP shall be calculated as follows:

F3 $MRP_{ey} = \sum_{d(ey-1)} BP_{d\ (ey-1)}/\sum d_{\ (ey-1)}$

Where:

BP Is the time weighted average of Summer and Winter Baseload EFA contract prices quoted on day d in the preceding EFA Year (ey-1) for delivery in the current EFA Year (ey), defined as:

F3A $BP_{d\ (ey-1)} = (BP\_S_{d(ey-1)} * ED\_S_{ey} + BP\_W_{d(ey-1)} * ED\_W_{ey})/ED_{ey}$

Where:

BP_S Is the Summer Baseload Price for EFA year ey quoted on day d in the preceding EFA year (ey-1).

BP_W Is the Winter Baseload Price for EFA year ey quoted on day d in the preceding EFA year (ey-1).

ED_S Is the number of days in the EFA Summer Season in EFA year ey as defined by the EFA calendar.

ED_W	Is the number of days in the EFA Winter Season in EFA year ey as defined by the EFA calendar.
ED	Is the number of days in EFA Year ey as defined by the EFA calendar.
$\sum_{d(ey-1)}$	Denotes the summation of price quotes (BP) for all EFA days in EFA Year ey-1 as defined by the EFA calendar.
$\sum d_{(ey-1)}$	Denotes the total number of days in EFA Year ey-1.

In the event it is determined that the MRP shall be calculated as a basket, each source (Price Index) shall be included at determined weights. Accordingly, F3 above is expanded as follows:

F4 $MRP_{ey} = (\sum_{j,\, d(ey-1)} BP_{j,d\,(ey-1)} * W_j)/\sum d_{(ey-1)}$

Where:

$BP_{j,d}$ (ey-1)	Is defined as in F3A for each Price Index (j).
W_j	Is the weight attributed to Price Index j such that the sum of all weights for all Price Indices included in the MRP equal 1.
$\sum_{j,d(ey-1)}$	Denotes the summation of price quotes (BP) for each Price Index on all EFA days in EFA Year ey-1 as defined by the EFA calendar.

ii. CfD Volume

1. Payments under the CfD can either be based on output (e.g. MWh), a measure of availability, or a mixture of both. Paying on output is the most straightforward approach as there is a clear link between the low-carbon support and the low-carbon electricity. However supporting low-carbon generation based solely on output leads to dispatch distortions as this plant will generate even when the electricity price it receives is lower than its running costs, so that it can access support. This has two related consequences:
    - Firstly it has the potential to distort the merit order as the marginal costs of generation plant are no longer defining the order in which plant generates.
    - Secondly, where plant have very low marginal costs, such as wind or nuclear, they have an incentive to keep running to access the support offered even when prices are negative (i.e. generators are prepared to pay someone to take their power).

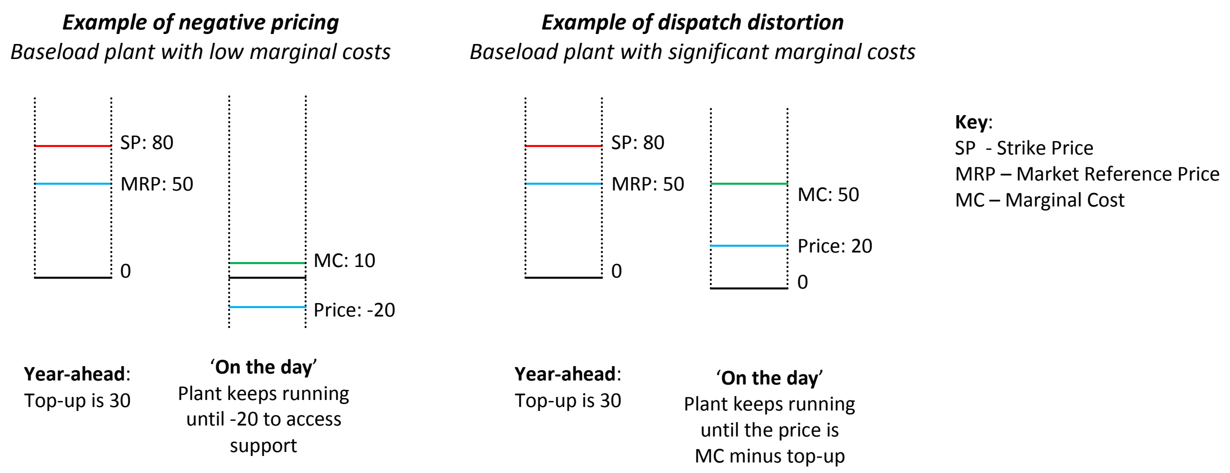
2. Payments based on availability could either be based purely on the capacity of the plant (with possible conditions on build) or conditional on demonstrating availability. The total capacity on which availability payments are made would have to be agreed at the start of the CfD (e.g. based on a percentage of name plate capacity), to allow for appropriate payments to be calculated. This is referred to as paying on 'firm volume'.

3. This section considers the nature and the likely extent of the distortions caused by paying on output, then outlines the design of the CfD that the Government is minded to adopt and the rationale for choosing this design.

Dispatch distortions caused by paying on output

4. As mentioned above, paying on output affects the dispatch decisions of CfD supported plant as they will generate even when the electricity price is lower than their marginal cost in order to access support payments. The nature of the CfD also means that dispatch decisions are affected when the reference price is higher than the strike price; when this happens CfD plant has an incentive to turn off when the price 'on the day' is higher than its marginal costs.

Figure 8: Illustration of the dispatch distortion caused by paying on output



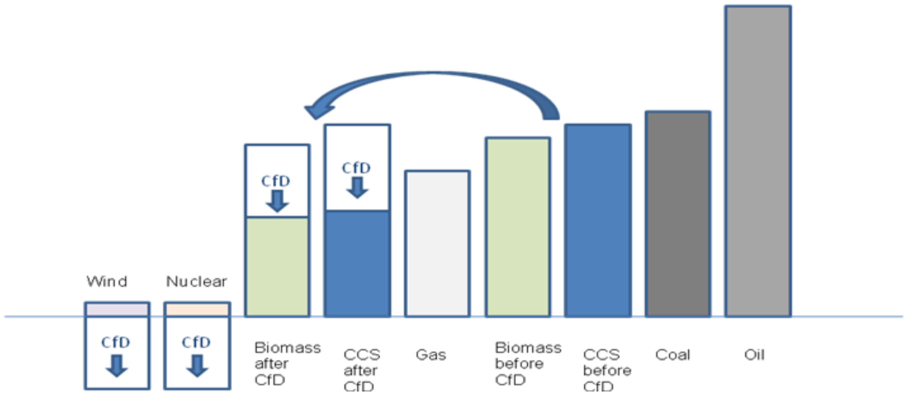
Distortions to the merit order

Nature of the distortion

5. Low-carbon plant with very low marginal costs such as wind and nuclear will always be at the bottom of the merit order and dispatched ahead of other plant with higher marginal costs (such as biomass, CCS-equipped or conventional fossil fuel plant). Therefore providing support to low marginal cost plant based on output does not change the order in which plant generates, but it does result in a specific type of dispatch distortion, negative pricing, which is considered below.

6. Paying on output could however result in low-carbon plant with significant running costs ('mid-merit' plant) being dispatched ahead of other plant with lower marginal costs. For example biomass and CCS-equipped plant could be dispatched ahead of gas plant even if the price of biomass and CCS were higher than the price of gas.

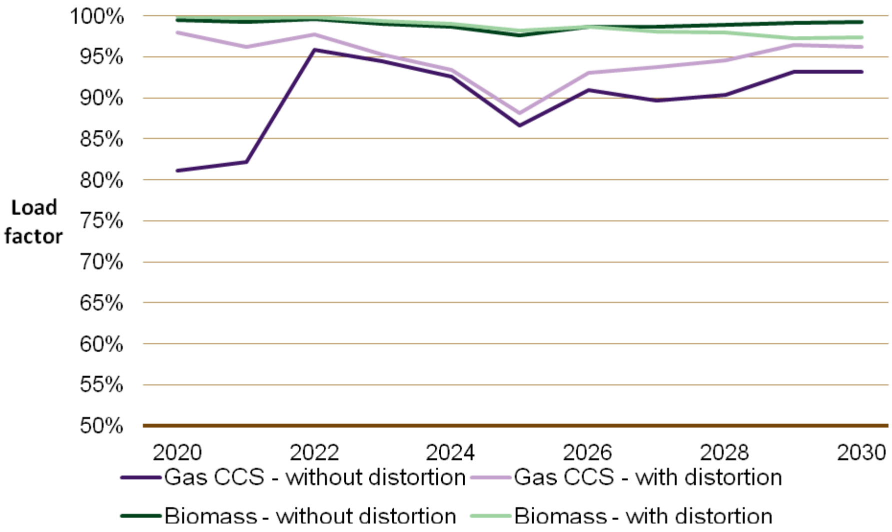
Figure 9: Illustration of distortions to merit order caused by paying on output



Extent of the distortion

7. To assess the likelihood of this type of distortion to the merit order, DECC commissioned consultants LCP to model the electricity system to 2030[16]. This work showed that under a central set of assumptions, paying on output would result in a minimal amount of dispatch distortion for mid merit plant. The figure below shows the load factors of biomass and gas CCS plant, when the CfD is paid on metered output (with distortion to dispatch) and firm volume (without distortion). This result is however highly dependent on the assumptions, particularly around the price of biomass, fossil fuel prices and the carbon price; if the price of biomass were assumed to be higher then the distortion would be greater. Similarly if the carbon price were lower the distortion would be greater.

Figure 10: Possible extent of the distortion to the merit order caused by paying on output



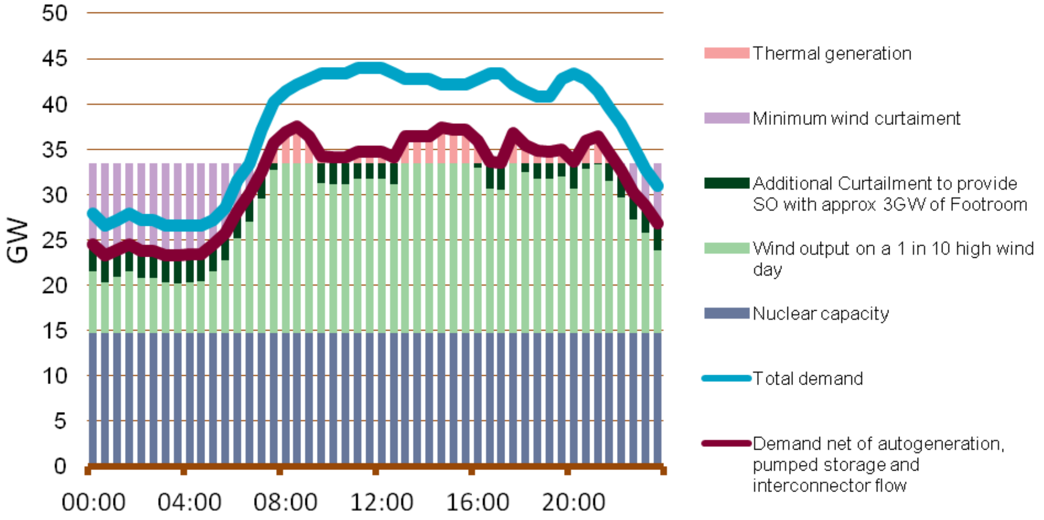
Negative prices

Cause of negative pricing

8. In the future with a high penetration of low marginal cost plant such as wind and nuclear, it is possible that there will be periods when the electricity generated by wind and nuclear will be greater than demand, as illustrated below. In this scenario prices could turn negative, meaning that there is plant on the system that is prepared to pay someone to take their electricity. Generators are prepared to pay someone to take their power either because they want to access support for low-carbon generation, or because their costs of turning off or down are significant, or both.

[16] LCP, *Assessment of dispatch distortions under the Feed-in-Tariff with Contract for Difference policy,* May 2012 (to be published on DECC website in June 2012).

Figure 11: Illustration of the potential cause of negative prices – high wind output and low demand in 2030.



Possible extent of negative pricing

9. DECC has reviewed three studies that have looked at the likelihood of negative prices in the future. All three of these studies indicate that negative prices will become increasingly likely as the amount of intermittent generation on the grid of increases:
   - A Poyry study in 2009 gave a detailed assessment; the summary report[17] indicated 'increased periods of extremely high or very low, sometimes negative, prices' in high wind scenarios.
   - The LCP study for DECC showed that there would be potentially above 600 hours of negative prices in 2030 under a central set of assumptions. In this scenario, there is assumed to be very little response from the demand side or from storage to these low and negative prices and this represents a worst case scenario from this perspective.
   - A report by National Grid in 2011[18] warns of a 'significantly higher and more variable operating reserve requirement' due to uncertainty and variability from likely generation mix. Specifically:
     – it may be necessary to curtail wind output on about 38 days per year by 2020
     – coincidence of high wind days with low demand periods may only be 3 times per year.

10. The disparity in these results is likely due to different assumptions used around supply and demand forecasts. In particular the LCP study includes a sensitivity

[17] Poyry, *Implications of Intermittency: How wind variability could change the shape of the British and Irish electricity markets*, July 2009
[18] National Grid, *Operating the Electricity Transmission Networks in 2020*, June 2011

analysis that demonstrates a small change in forecasts can lead to a greater change in the potential for negative prices.

Box 2: International response to oversupply and negative prices

Negative prices have the potential to feature in any system where inflexible plant make up a significant proportion of the generation fleet. Support payments can potentially further increase the likelihood of negative prices. Many countries with high installed wind capacities have policies in place to mitigate negative effects on the market from wind plant.

In **Spain** 'programmed curtailments' occur where wind generators are not compensated if curtailed, and 'real time curtailments' where they receive compensation of about 15% of the wholesale price for each hour (with no premium), which is multiplied by forecast production.

In **Ireland**, where wind is curtailed the generator receives an availability payment equivalent to the market price for full output, but loses support payments.

In oversupply situations in **Germany** conventional generation must be constrained first; following this price caps prevent prices going overly negative. Renewables curtailment can follow with compensation equal to lost revenues. If emergency curtailment is applied no compensation is due.

Impact of negative pricing

11. The analysis reviewed shows that there is significant potential for negative prices caused by paying on metered output. These negative prices would send a signal for the demand side, storage and interconnected markets to respond to a high penetration of less flexible and intermittent plant, but they would present a significant challenge to the System Operator in balancing the system. The LCP study illustrated that these negative prices could provide a transfer to storage and the demand side of around £25m per GW of storage and demand side response assuming that there was no impact on the price of the storage or demand side response.

12. The System Operator already faces challenges in balancing the system. The System Operator takes action to balance the system by constraining off plant ahead of gate closure[19] (pre-gate closure trades) and does this at the moment for a number of reasons:
    - to address oversupply in specific areas resulting from grid constraints. These trades are executed on a plant specific basis;

[19] Gate closure is the point in time when market participants notify the System Operator of their intended final physical position and is set at one hour ahead of real time.

- to manage under or oversupply where the market does not appear to be responding in suitable timescales. These trades are not locationally specific and are carried out via brokers, power exchanges or the interconnectors; and
- to ensure that there is sufficient margin to manage the system.

13. If the CfD were paid purely on metered output, the System Operator would have to take additional steps, such as increasing the number of pre-gate closure trades, to balance the system if the demand side or storage did not respond.

14. Negative prices could also result in very high CfD payments should the reference price be very negative, as the CfD plant would always be topped up to the strike price, no matter how low the reference price was.

Proposed approach

Paying on metered output

15. The Government is minded to pay on metered output for the following reasons:
    - it is simpler as there is a clear and direct link between the low-carbon output and the low-carbon support;
    - there is no risk of paying when the plant is not available and not generating; and
    - analysis demonstrates that the distortions to the merit order are likely to be limited. Whilst this conclusion is heavily dependent on assumptions around fuel prices and the carbon price, even if the CfD does alter the position of the CfD plant in the merit order, it can be argued that this meets Government objectives as it maximises the output from low-carbon plant that is being supported through the CfD.

16. It can be argued that the dispatch distortions will lead to higher costs for consumers as plant with higher marginal costs is dispatched first. However if the CfD plant were running at lower load factors, investors in CfD supported plant would need to cover their capital costs over fewer running hours and the strike price would be higher as a consequence. Therefore the impact on overall costs to consumer of supporting a given level of low-carbon output may be similar under metered output or firm volume.

17. It is also important to note that paying intermittent plant on firm volume means that they would have to pay back the difference between the reference price and the strike price when the former is higher. However, as intermittent plant cannot control their output, they would not know whether they would be generating (and thus earning the market price) in such a scenario. As a result, this would

represent a significant and unknown risk for intermittent plant. In addition, when the reference price is high, it is more likely that at least some intermittent CfD plant will not be generating (as higher prices are likely to be caused by the more expensive fossil fuel plant coming onto the system due to unmet demand from intermittent plant). It is generally accepted therefore that paying on firm volume is not a practical solution for intermittent plant.

Paying on availability when the reference price is negative

18. To address potential negative prices, the Government is minded to pay CfD supported plant based on output unless the reference price drops below zero, in which case it would be paid on availability for the following reasons:
    - it makes it easier for the System Operator to balance the system and reduces distortion in the balancing mechanism (resulting from intermittent plant requiring higher prices to turn off in order to offset foregone CfD revenues);
    - it provides a clear and transparent set of criteria for paying the CfD should the reference price be negative; and
    - it limits the scale of the CfD payments, making it more predictable for generators, suppliers and Government. It also reduces the strike price as generators know they will be paid even if prices are negative. The strike price would otherwise be higher to cover this risk.

19. The CfD availability payment would be fixed at the strike price (i.e. the top-up to the strike price as if the reference price is zero). CfD plant would then have an incentive to stop generating once the reference price (day-ahead in the case of intermittent and year-ahead in the case of baseload) dropped below zero[20].

The impact of paying on availability

20. The impact of paying on availability if the reference price is negative is different for intermittent and baseload CfD plant because of the different reference prices used.

21. The LCP study showed that the day-ahead reference price for intermittent is likely to be negative under a base case set of assumptions. Therefore under this approach intermittent plant has an incentive to turn off if supply is greater than demand, as it would be paid more if it shut down and received availability payments.

22. The baseload CfD however uses a year-ahead reference price which would only turn negative under the most extreme scenario. If the day-ahead electricity price

[20] With possible adjustments for the costs of shutting down.

were negative, baseload plant would not necessarily turn off; this plant would have an incentive to turn off only when the electricity price is lower than its marginal costs minus the top up it receives. However the LCP modelling demonstrated that even with a high take up of mid merit plant (biomass and CCS-equipped plant), this plant would have turned off by the time the price is negative.

23. It is likely however that less flexible nuclear would still be running, even when prices are negative, given the costs they incur to turn down or off. Pre-gate closure trades by the System Operator indicate that nuclear plant is unwilling to turn off even at high negative prices, which is a result of their technical characteristics rather than the support they are receiving. It is possible that at some point in the future nuclear could be more flexible and therefore able to respond to market signals. However this CfD design still provides nuclear with an incentive to turn off, should prices go negative. This is therefore a driver to develop flexibility.

Next steps

24. DECC will work with the System Operator to confirm details of how availability will be measured when prices are negative. This availability payment will need to be based on wind forecasts at the day-ahead stage, to provide wind generators time to schedule the plant operation. There is also a question of whether availability payments should be adjusted to reflect the costs of shutting down and how to minimise these costs.

25. The Government is continuing to work with the System Operator and industry to develop policy on how CfD-supported plant is paid following instruction to adjust its output for operational reasons.

Measurement of CfD volume and metering requirements

26. Paying the CfD on metered output means that in order to calculate CfD payments, the settlement agent will need to capture accurate and timely data on the volume of electricity produced, in each settlement period, by each CfD-supported plant. As a result, to qualify for allocation and payments under a CfD, low-carbon plant will need to install an appropriate metering device and register this device with the settlement agent.

27. There are existing systems that are well-established in the market for measuring and processing output data for various purposes, including balancing and settlement, and it is both efficient and sensible to make use of these systems if appropriate.

28. The Government has discussed possible approaches with the System Operator and Elexon, and is currently minded that CfD volume should be based on the output recorded by 'Dedicated BM Units', with a multiplier to take account of transmission losses. The reasons for this are as follows:
    - 'BM Units' are already used by Elexon in the context of the balancing and settlement code;
    - they only measure the output from the relevant low-carbon plant, excluding metering data associated with all other plants;
    - they will enable both accurate and timely payments (see also section E below on settlement); and
    - this can be applied to both transmission and distribution connected plant (for distribution connected plant output could be measured at the transmission boundary, adjusted for line losses).

29. Most transmission connected generation, and a small number of distribution connected plants already use dedicated BM Units and register these units with Elexon. The precise arrangements for distribution connected generators are still under consideration, but one option would be for such generators to register and supply metering data through their offtaker. The offtaker would in this case need to register an additional BM Unit for the plant to enable it to be distinguished from the base BM Unit and submit data as relevant to the settlement agent. The additional costs of these metering requirements to distribution connected generation are understood to be minimal.

30. A more technical translation of these emerging proposals, to give a greater indication of what the relevant CfD terms might look like, is set out in Box 3.

Box 3: Illustrative terms for CfD Volume and Metering Requirements

CfD Volume

The CfD Volume (CV) for plant located in the GB market is the:

Metered Energy delivered by the Generator in the CfD Settlement Period at the Transmission Boundary, corrected for the BSC Transmission Loss Multiplier, or Plant Availability when constrained off at the instruction of the System Operator.

For the purpose of this agreement, all CfD Generators, whether connected to the Transmission Network or a local Distribution Network, must register Dedicated BM Units to enable accurate measurement of metered generation.

The CfD Volume (CV) for a Generator for a CfD (f) in a CfD Settlement Period (t) is determined by the following formula:

F5	$CV_{f,t} = \sum_{j(t)}\sum_{i(f),j}(QM_{i,j}*TLM_{i,j})$

Where:

$QM_{i,j}$	Is the BM Unit Metered Energy at the Transmission System boundary for the BM Unit(i) in BSC Settlement Period (j) as defined by the BSC. For CfD Generators connected to the Transmission Network, $QM_{i,j}$ is the Export measured at the point of connection (i.e. at the 'station gate'). For CfD Generators connected to local Distribution Networks, $QM_{i,j}$ is the Export adjusted for line losses (LLFs) for that BM Unit as determined under the BSC.
$TLM_{i,j}$	Is the Transmission Loss Multiplier for the BM Unit (i) in BSC Settlement Period (j) as determined under the BSC.
$\sum_{i(f),j}$	Denotes the sum of the Production (or possibly Consumption) BM Units (i) associated with the CfD (f) in the BSC Settlement Period (j).
$\sum j(t)$	Denotes the sum of all BSC Settlement Periods included within the CfD Settlement Period (j).

Metering Requirements

To qualify for allocation and payments under a CfD, all Metering Points associated with the low-carbon generation plant for which the CfD is allocated must:

- be identified in Schedule X; and
- assigned to one or more Dedicated BM Units which are registered with the Settlement Agent continually throughout the term of the CfD.

A Dedicated BM Unit is a BM Unit which solely captures the metering data from the Metering Points associated with the relevant low-carbon plant. As defined, a Dedicated BM Unit excludes all metering data not associated with generation from the low-carbon plant.

Registering Dedicated BM Units

All CfD Generators registered under the Central Metering Registration Service (CMRS) are responsible for correctly registering Dedicated BM Units under the BSC and notifying the Settlement Agent of their ID.

For distribution connected CfD Generators which register under the Supplier Metering Registration Service (SRMS) it is incumbent on the CfD Generator to ensure that the relevant Supplier apply for and obtain an Additional BM Unit for the low-carbon plant. The Additional BM Unit must include all Metering Points associated with the low-carbon plant to enable the metering data to be distinguished from the Supplier's Base BM Unit for the purpose of settlement of the CfD. This requires the Supplier to:

- register a BM Unit with the Central Registration Agent (CRA) in accordance with BSC K3.3.2 and BSC Procedure BSCP15; and
- submit data to the relevant Half Hourly Data Aggregator (HHDA) identifying which Metering Points should be included in the Additional BM Unit.

iii. CfD Length

1. This section sets out emerging thinking on CfD length, that is, the length of the CfD from the payment start date as defined in section C. In principle, the Government is minded to select CfD lengths that strike an acceptable balance between minimising the overall costs on consumers; ensuring that the CfD scheme is affordable; and facilitating low costs of capital.

2. Analysis is currently being done on CfD lengths for different types of low-carbon generation, focussing in particular on the impact of different CfD lengths on:
    - electricity consumers, in terms of the net present value of support provided over the lifetime of the CfD;
    - the affordability of the CfD scheme; and
    - investor financing costs, including the availability of debt financing for project financed independent generation.

3. The analysis has included modelling the project cashflows for a range of projects to examine the interactions between strike prices and support costs for different CfD lengths. To inform this modelling, information has been drawn from published sources, including cost assumptions from reports prepared by ARUP[21] and Parsons Brinkerhoff[22] for DECC, confidential evidence collected as part of the Renewables Obligation Banding Review Consultation, and discussions with a range of stakeholders, debt financiers and equity investors. Key assumptions underpinning the modelling include:
    - that project finance rather than on balance sheet financing is used;
    - that project finance debt providers will require debt to be repaid within the shorter of the CfD life or the Power Purchase Agreement (less a 'tail' of 1-2 years) or 15 years;
    - projects could secure debt financing as long as minimum cover ratios are met (subject to caps on maximum allowed gearing); and
    - that the CfD has a fixed index-linked strike price for its entire life.

4. The following factors are central to the analysis and initial conclusions:
    - Investors discount future costs and returns at a higher rate than Government's social discount rate. Other things being equal, this points towards shorter CfDs as the cost to consumers of future payments is higher than the benefit to developers.

[21] *Review of the generation costs and deployment potential of renewable electricity technologies in the UK*, ARUP, October 2011 http://www.decc.gov.uk/assets/decc/11/consultation/ro-banding/3237-cons-ro-banding-arup-report.pdf

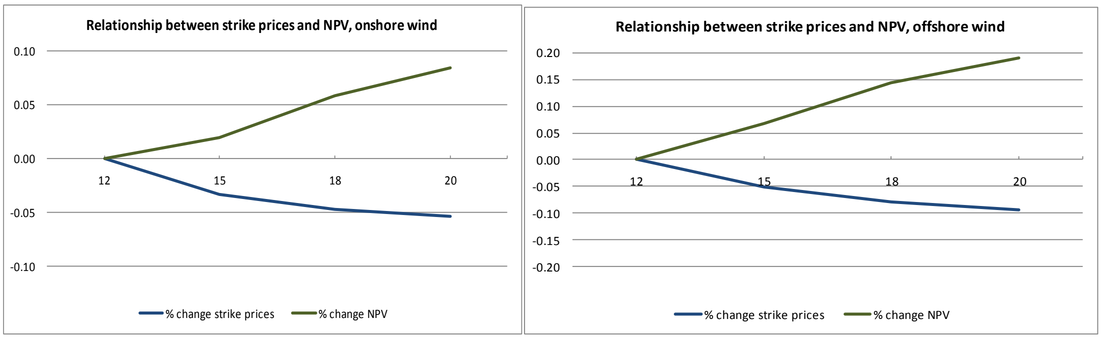
[22] *Electricity Generation Cost Model – 2011 Update Revision 1*, Parsons Brinkerhoff, August 2011 http://www.decc.gov.uk/assets/decc/11/about-us/economics-social-research/2127-electricity-generation-cost-model-2011.pdf

- Longer CfDs generally lead to longer term revenue certainty, a higher degree of investment security and possibly lower costs of capital. They may also be attractive to investors who assume a lower wholesale electricity price trajectory than the Government.
- Shorter CfDs require higher up front strike prices to attract investment, which may affect affordability from a public finance perspective.

5. For renewable technologies, the initial analysis points to a CfD length of 15 years. A CfD length of 15 years appears to represent an effective balance between enabling a range of projects to secure debt finance and achieve required returns to equity, and minimising the costs of consumer support.

6. Figures 12 and 13 below show the relationship between the strike price and support costs for intermittent CfD lengths of 12, 15, 18 and 20 years[23] (onshore and offshore wind are shown). As the length of the CfD increases from 12 to 20 years, the size of the support provided by the CfD increases – while strike prices are lower this is outweighed by the longer length of support provided. The modelling indicates that a CfD length of 12 years may in fact be optimal in terms of lowest overall support costs, but Government is mindful of investor concerns that this may impact on the cost or availability of debt finance for some renewables projects with different risk profiles (for example, some offshore wind projects). A 15 year CfD length appears to represent an effective balance. Discussions with stakeholders on this will continue.

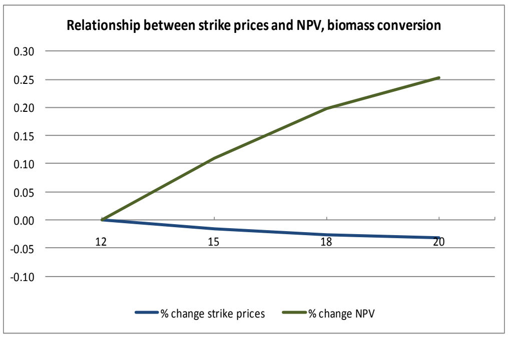
Figures 12 and 13: Relationship between strike prices and NPV, onshore and offshore wind

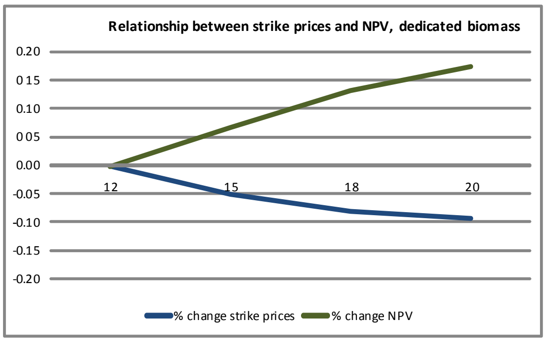


7. Figures 14 and 15 below show broadly similar results for dedicated biomass and for biomass conversion, although for the latter decisions on CfD length will also be affected by the maximum operational life of the converted plant.

[23] The following simplifying assumptions have been made: that required debt returns are fixed as long as minimum cover ratios are met, and that equity investors' hurdle rates do not vary with gearing/variability of prospective equity returns.

Figures 14 and 15: Relationship between strike prices and NPV, biomass conversion and dedicated biomass





Similar analysis for other renewable technologies (including for example wave and tidal) has not yet been carried out.

8. The Government has yet to form a firm view on the optimal CfD length for nuclear plants, but in principle would expect a CfD length of no less than 15 years. In part due to the possible scale of these investments and the potential operational life of the plant, the Government considers that it is prudent to form a view following the Financial Investment Decision Enabling process. This may include a decision as to whether to establish a standard CfD length for nuclear as a technology, or alternatively vary CfD length by project.

9. In relation to early stage CCS projects, it may be appropriate to allow for different CfD lengths for different projects, for example distinguishing between a retrofit to an existing plant and a new build thermal plant with CCS. In addition, the terms on which such projects are likely to be financed will become clearer as the CCS Commercialisation Programme competition progresses and this will inform the Government's view on CfD length. Subject to the outcome of the competition, the initial view is that CfD length for projects supported under the Commercialisation Programme should be 10 years.

iv. Inflation indexation

1. The EMR White Paper indicated that the Government was minded to adjust the CfD strike price for inflation. This remains the proposed position, on the basis that it is likely to represent a more efficient allocation of risk between investors and consumers. This is reflected by the fact that most international feed-in tariff regimes including for example, the Czech Republic where indexation is applied within a cap and collar, and Spain where FITs are updated in line with CPI with a correction factor of 0.25%, either take or share inflation risk with investors.

2. In coming to a decision there are a number of principles that need to be considered:
    - the degree to which sharing inflation risk leads to a more efficient allocation of risk;
    - the degree of inflation risk faced by different generators; and
    - the simplicity of the system for investors and overall administrative burden.

Efficient risk allocation

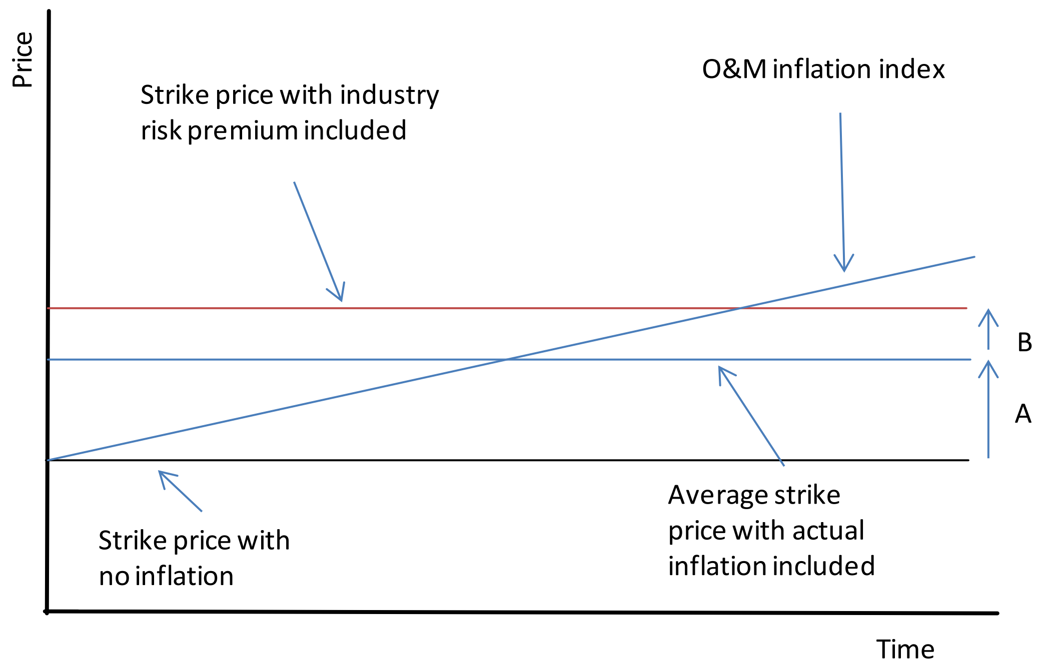
3. Any long term arrangement is likely to need to reflect the fact that input prices will change over time. This can be captured in the upfront costs or through indexation i.e. in the context of the CfD a higher strike price may be required if variable costs are not indexed, or conversely a lower strike price may be required if variable costs are indexed.

4. If a generator's inflatable costs are not indexed, then the CfD strike price would be higher and reflect the risk premium associated with uncertainty over future inflation. However, indexing variable costs to an appropriate price index removes the inflation risk from the generator and hence the risk premium. HM Treasury guidance has indicated that indexing these costs is therefore likely to provide value for money[24]. The box below provides further illustration of this point.

[24] HM Treasury, Application Note – Interest rate and inflation risk issues in PFI contracts, 2005.

Box 4: Indexation of Operation and Maintenance costs

Indexing Operation and Maintenance (O&M) costs to an appropriate price index removes the inflation risk from the generator. If a generator's costs are not indexed then the strike price would need to reflect the risk premium that the technology in question would place on cost inflation. This is illustrated in the graph below, where the average strike price taking into account actual inflation over the time period is represented by the horizontal blue line ('A', the difference between the black and blue lines, represents the costs associated with inflation). The red line represents the strike price after the technology's inflation cost risk premium has been included (if the strike price was set below this then the contractors may choose not to build). 'B' represents the risk premium. If the proportion of O&M costs in the strike price is indexed then the strike price will move in line with the 'O&M inflation index' over time, but with the risk premium excluded.



Exposure to inflation risk

5. The Government is still considering what proportion of the strike price should be indexed, or similarly what proportion of the index the strike price could be adjusted for. Whilst investors face genuine cost inflation risk both at construction and operation, projects have different exposures to inflated costs. Debt repayments are generally fixed nominal costs that do not move with inflation, and the risk of construction costs rising due to inflation is in most cases typically assumed by investors and hedged through existing contractual mechanisms.

6. Full indexation of the strike price therefore runs the risk of over-compensating for the inflation risk faced by investors. Adjusting the full CfD strike price may

therefore not be in the best interests of electricity consumers, depending on the extent to which the administrative price setting processes referred to above could factor this transfer of risk into the calculation of a lower up front strike price.

Simplicity and administrative burdens

7. Government is minded to link the strike price to a general inflation index. This is largely because general inflation indices:
    - are simple, reliable, published and cover a wide range of goods and services;
    - can be applied in a standard way across different low-carbon technologies; and
    - are familiar to investors and widely used across other similar regimes.

8. Creating a basket of specific indices, or attempting to map the index more precisely to the actual uncontrollable, inflatable costs incurred by a project, in a pure sense may be the economically efficient solution. However, this would be complex, would need to be technology specific and possibly project specific, and in extremis may necessitate administratively burdensome ex-post assessments of cost for individual projects to ensure accurate strike price adjustments.

9. Government is currently minded to choose CPI as a standardised and established inflation measure that is familiar to international institutional investors. However, discussions on these issues with stakeholders will continue, and further analysis will be carried out to determine:
    - the choice of index (RPI or CPI);
    - whether an inflation link to the full strike price, a proportion of it or some other arrangement (e.g. CPI–X) achieves the right balance between reflecting inflation risk and attracting institutional investors from both within and outside of the UK; and
    - how these considerations are balanced against simplicity for investors.

10. A more technical translation of these emerging proposals, to give a greater indication of what the actual CfD terms might look like, is set out in Box 5. The example below assumes that a proportion of the CfD strike price is index linked, as opposed to linking the full strike price to a proportion of the inflation index.

Box 5: Inflation Indexation

CfD Strike Price (CSP) – Inflation Indexation

The CfD Strike Price shall be adjusted annually at the end of each Calendar Year for inflation, using the United Kingdom Consumer Price Index (CPI) and in accordance with the following formula:

F6	$CSP_y = CSP_0 *(1-CR) + CSP_0 * CR * CPI_{y-1}/CPI_{0-1}$
Where:	
CSP_y	is the CfD Strike Price applicable in current Calendar Year (year y)
CSP_0	is the CfD Strike Price at the time of CfD allocation
CPI_{y-1}	is the accumulative value of the CPI as reported by the [Bank of England/Office of National Statistics] for the [final quarter/month of December] in Calendar Year y-1
CPI_{0-1}	is the accumulative value of the CPI as reported by the [Bank of England/Office of National Statistics] for the [final quarter/month of December] preceding the Calendar Year in which the CfD was awarded.
CR	denotes the proportion of the CfD Strike Price which is adjusted for the CPI. If CR is set to 1, the CfD Strike Price is fully adjusted for the CPI (CSP_0 * (1-CR) = 0) whereas CR values less than 1 but greater than 0 implies partial adjustment.

v. Fuel price indexation

1. The EMR White Paper indicated that for biomass, the lack of a single, established biomass price index and the diversity of feedstocks would make it extremely difficult to calculate a single price to index against. These factors have not changed. Therefore the Government remains minded not to link the CfD strike price to fuel costs for biomass, and considers that this risk is best managed by generators and taken into account in the calculation of the (administered) CfD strike price.

2. For CCS projects selected through the Commercialisation Programme competition, the Government is minded that the CfD should provide for some indexation as a hedge against long term fuel price variability. The precise arrangements for this indexation are still under consideration, including whether to adjust the strike price or the reference price and the choice of price source. This work will continue over the summer and conclude in line with the competition negotiations.

3. The Government will continue to consider the best arrangements for supporting commercial CCS over the longer term, taking into account the experience of the CCS Commercialisation Programme. This includes the case for providing a link to fuel costs.

vi. Change in law

1. Change in law clauses are designed to allocate risks associated with the occurrence of changes in law between parties to a contract. They are commonly found in project agreements relating to major capital assets, including those in which a private company contracts with a Government or quasi government entity.

2. In principle, the Government is minded that in case of a change in law, the CfD should be capable of being amended as necessary to enable ongoing performance of the asset and compliance with the obligations in the CfD. The occurrence of a change in law is not expected to provide the parties with a right to suspend performance or terminate the CfD.

3. In the case of a qualifying change in law, the Government is further minded that the CfD should be adjusted so as to preserve the overall balance of risk and reward between the parties. The parties to the CfD would be expected to take all reasonable steps to mitigate any adverse effects of a change in law.

4. Whilst there is no exact precedent for the CfD, the forms and scope of change in law protection that the Government has in the past provided to private sector investors in major capital projects are being examined, together with examples of change in law protection seen in relevant private sector commercial contracts, to inform decisions on this issue.

5. The Government is seeking further legal advice on the drafting of change in law provisions, and will continue to engage with industry and other stakeholders. Over the summer proposals will be developed on:
   - the scope of change in law protection in the CfD and what should constitute a 'qualifying change in law';
   - the mechanisms for
     - notification of a change in law
     - assessment of whether the change in law is a qualifying change in law
     - negotiation of the impact of a change in law
     - resolution of any disputes arising under the change in law provision including the mechanism for challenge;
   - the approach to risk sharing, including the use of materiality thresholds; and
   - the approach to administering compensation payments.

6. The Government is mindful that this is an extremely important issue for investors and so plans to share these proposals for discussion with market participants at the earliest possible opportunity, and welcomes views.

vii. Dispute Resolution

1. Over the course of a CfD disputes are likely to arise, from time to time, between a generator and supplier(s) with respect to the terms of that CfD. Those disputes could relate to matters of interpretation of the CfD; defaults (actual or alleged) under the CfD; and amendments to the CfD to deal with, for example, changes to price indices. The disputes may affect one or more suppliers party to the CfD, and may be specific to one particular CfD or of general application to a number of CfDs.

2. The Government has not yet formed a firm view on precisely how such disputes should be managed and ultimately resolved, nor on whether different provisions should be made for different types of disputes (e.g. a factual or technical dispute about the application of a CfD term as opposed to one about the interpretation of a CfD term).

3. As a general principle, the Government recognises the importance of ensuring that any disputes arising under the CfD should be capable of resolution in a timely way, with a particular view to avoiding undue cashflow impacts on generators or suppliers. The Government is also clear that dispute resolution should take place within an ordered structure that is clear and well understood by investors.

4. The Government acknowledges that the multi-partite nature of the current CfD design means that efficient dispute resolution procedures may not be as straightforward as in the case of ordinary bilateral contracts where the number of parties are limited. However, the Government does not believe that this presents an insurmountable challenge.

5. There are various methods for managing and resolving disputes. In order to develop optimal arrangements for dispute resolution under the CfD, the Government is seeking further legal advice in a range of areas to enable consideration to be given to:
    - providing for an informal dispute resolution process in some cases (for example where there is genuine misunderstanding over terms which is capable of straightforward resolution);
    - providing for a procedure to enable negotiation (and allowing for negotiated settlement) in certain circumstances;
    - establishing within the CfD an ‘independent expert’ function to resolve certain types of disputes and, if necessary, determine variations to the CfD;
    - providing, through legislation, for an arbitration procedure as a mechanism to resolve some or all disputes arising under the CfD;

- the enforcement of CfD terms following a dispute, whether referred to an expert or arbitrator;
- what role the Secretary of State should have (if any) either in general or in respect of particular types of dispute, from making representations to having a more formal role in the decision making process.

6. The Government is mindful that this is an extremely important issue for investors and so plans to share these proposals for discussion with market participants at the earliest possible opportunity, and welcomes views.

viii. Adjustment of reference prices (and other CfD parameters)

1. Given the longevity of the CfD, it is important to consider arrangements for adjusting reference prices and other CfD parameters in response to changes in trading arrangements which change or render variable definitions invalid, or changes in market liquidity or trading platforms which might impact the validity of the indices used to calculated the reference price.

2. As such, the Government is minded to include an 'independent expert' role within the CfD framework. This is distinct from the Panel of Technical Experts that will scrutinise the System Operator's analysis. Trustees or independent experts have been appointed in other European countries in order to oversee and validate auction outcomes. Power Purchase Agreements also tend to refer to an independent expert to determine any changes to the PPA in response to changes in the market which alter the commercial balance of the contract when it was agreed.

3. Such an independent expert role would be independent of all parties with a commercial interest in the CfDs and in principle would be mandated to ensure (as far as is possible) that the derivation of the price and volume variables applied in the settlement of the CfD remain valid over time. An independent expert's responsibilities could for example include:
    - periodic review of the source and calculation of the MRP to ensure they remain highly representative of e.g. Day Head Hourly Prices and, if required, determination of amendments; and
    - amendment of the volume variables applied in determining CfD Volume and Supplier Allocations in the event that changes render these variables invalid or unavailable.

4. The Government will give further consideration to the role and mandate of such an independent expert, and will engage with stakeholders to carry out further analysis and work.

E. LEGAL FRAMEWORK AND PAYMENT MODEL

As set out in the EMR White Paper and Technical Update, the System Operator will administer the CfD mechanism (initially allocating CfDs and later running auctions). However the Government (in consultation with the Devolved Administrations) will retain responsibility for taking key decisions on the CfD, informed by evidence and analysis from the System Operator.

The draft Energy Bill outlines that the CfD will be an instrument that sets out obligations on suppliers and generators. The aim is to provide investors with a level of certainty about the legal status of the CfD that is equivalent to a conventional contract with a counterparty who has a strong credit rating. The CfD would be crystallised when it is issued; that is, the obligations would come into force and stand separate from the underlying legislation. Therefore even if the regulations setting out the CfD scheme were subsequently amended, the CfDs issued beforehand would remain as initially agreed. In addition to providing statutory backing of the CfD, other measures have been identified to reinforce this regulatory certainty.

However, the Government recognises strong concerns have been raised by industry about this model particularly around whether it can provide an adequate framework to support planned levels of investment, or whether a model which is broadly similar to a conventional bilateral contract with a single counterparty would be preferable. Government analysis shows that the model as set out in this section could work, but recognises that this approach would be novel and that concerns from industry persist. The Government will continue to actively consider the merits of alternative models that use a single counterparty, in order to better address the concerns raised by industry. It is expected that there will be further detailed consideration given to these concerns as part of the pre-legislative scrutiny process.

CfD payments from suppliers to generators and vice versa will be facilitated by an agent settling payments in a manner similar to the settlement of payments under the Balancing and Settlement Code (BSC). The Government is minded that Elexon, which is a well established and trusted organisation that manages payments under the BSC, would be able to perform this role. To minimise credit risk for generators, payments will flow regularly and suppliers will be required to post collateral as under the BSC. These processes under the BSC have been highly effective in minimising the impact of supplier default.

Introduction

1. The broad framework for delivery was set out in the EMR Technical Update, which announced the Government’s decision to use the System Operator as the

delivery body for the CfD and Capacity Market policies. Government will be responsible for the policy approach, including setting objectives and making decisions on the mechanism, such as the strike price, or under auctions the volume of capacity to auction. Government will publish a delivery plan every five years, with annual updates, to set out its objectives, policy decisions and supporting analysis, such as the impact of policy decisions on the objectives.

2. The System Operator within National Grid will be responsible for:
   - providing evidence and analysis to Government on strike prices including the impact of different strike prices on Government objectives;
   - assessing the eligibility of the low-carbon generation plants that come forward against agreed criteria;
   - allocating CfDs; and
   - administering CfDs.

3. Details of these processes are set out in sections A and B. The payment obligations of parties to CfD instruments will be settled by a settlement agent responsible for administering payments. The System Operator will report regularly to Government on the delivery of the CfD. The System Operator will work, as necessary, with the System Operator Northern Ireland to undertake analysis and provide evidence of the Northern Ireland market.

4. Ofgem will continue its independent regulation of the market, incorporating the CfD. This could include monitoring the compliance of generators and suppliers with their new obligations and overseeing how the System Operator implements its new functions.

5. Further detail on the institutional framework, including the roles of the key parties, the decision-making process, and accountability arrangements, is set out in Annex A (EMR Institutional Framework). Government will confer the relevant delivery functions on the System Operator in secondary legislation.

Legal Framework

6. Having established the broad roles of the various institutions, this section sets out the legal framework of the CfD. This is important to give confidence to suppliers, generators and financial investors that the legal framework appropriately confers roles and responsibilities on parties such that they are willing to invest in low-carbon generation supported by CfDs. The design for the policy and legal framework and mechanics of the CfD has to balance a number of considerations, as follows:

- provide appropriate accountability to Ministers. In the near term, decisions on the low-carbon supply mix will ultimately reflect the policy objectives of Government;
- comply with EU guidelines on state aid;
- ensure no adverse liabilities are encountered by suppliers, low-carbon generators or Government and safeguarding the public finances; and
- administer the CfD in a practical and efficient manner, drawing on existing systems where possible.

Proposed legal framework

7. The model which has been most fully developed and which is provided for in the draft Energy Bill presented for pre-legislative scrutiny is one in which the CfD is an instrument created by statute, which sets out obligations on a number of parties. On one side is the generator, who has applied for a CfD. On the other side are all licensed suppliers, who will have obligations imposed upon them (which is similar to how the Renewables Obligation operates). The principal obligation on suppliers is that they are obliged to make payments on the basis of the difference between a reference price and a strike price. Other obligations, such as to provide relevant data and enter into agreements with administration bodies, facilitate the running of the CfD regime. In addition, for some large, baseload low-carbon generation, the CfD may need to contain obligations on the generator to provide a specified level of service over a particular timeframe, to ensure that public policy aims can be met. Government needs a greater level of certainty about decisions and timing of new capacity for very large projects than it does for smaller projects which come in larger numbers. This is in order to enable Government to make policy that supports an acceptable carbon trajectory and fuel diversity, as well as clarifying the likely position on security of supply. Whilst the generic terms of the CfD will be set out in regulations, each project will be issued with a specific CfD by the System Operator.

8. Once a CfD has been issued it will effectively require suppliers to meet their share of the obligations to the generator as set out under the CfD terms (or receive payments should the generator be ‘paying back’ due to the market price for electricity being higher than the CfD strike price). Each supplier’s share of the obligations will be determined by their market share, defined by metered use. This will enable costs of the mechanism to be passed through to consumers. Payments under the CfD will be administered by a settlement agent; the Government is minded to use Elexon as the Balancing and Settlement Code Company for this role.

9. A key risk for low-carbon investors is that payments do not flow from suppliers in either as timely or accurate fashion as intended (a form of credit risk). The

analysis presented later in this section demonstrates that the credit risk under the proposed model should be low, as it is designed to provide investors with a level of certainty equivalent to a contract with a single counterparty who has a strong credit rating.

10. Another core concern for generators is regulatory risk. This stems from the ability of Government or others (e.g. Ofgem or industry themselves) to change the regulatory framework, which may then have a detrimental impact on generators' expected revenues. With a conventional contract, this would be covered by change in law provisions or through a claim for breach. Under the model presented, the CfD places a set of obligations on the parties by law. Once a CfD has been issued it will stand alone. Whilst the regulations which determine the terms upon which CfDs may be issued can be amended over time, neither the Secretary of State nor the System Operator has any power to amend instruments which have already been issued. Once issued a CfD cannot be changed (except in accordance with its own terms). This provides generators with the same level of certainty as a conventional contract.

11. This model will also ensure accountability to Government, as Government will retain responsibility for setting out the policy approach and objectives, and for taking final decisions on the key parameters for the System Operator in administering the system. Further detail on the overarching framework that Government will put in place to deliver Electricity Market Reform is being published alongside this document in Annex A (EMR Institutional Framework).

12. The current assessment is that the model presented in the draft Energy Bill, of the CfD as an instrument issued by statute, should be capable of meeting Government needs for accountability whilst also providing assurance to investors. However in recognition that this is a novel framework and industry concerns persist, Government continues to assess the merits of adopting an alternative 'single counterparty' model. In this model, generators would be issued a contract with a single counterparty, potentially allowing more straightforward dispute resolution. Government will work with industry as the legal framework surrounding CfDs is developed, and additional views would be welcomed; in particular it is expected that the pre-legislative scrutiny process will explore these issues further.

Payment model

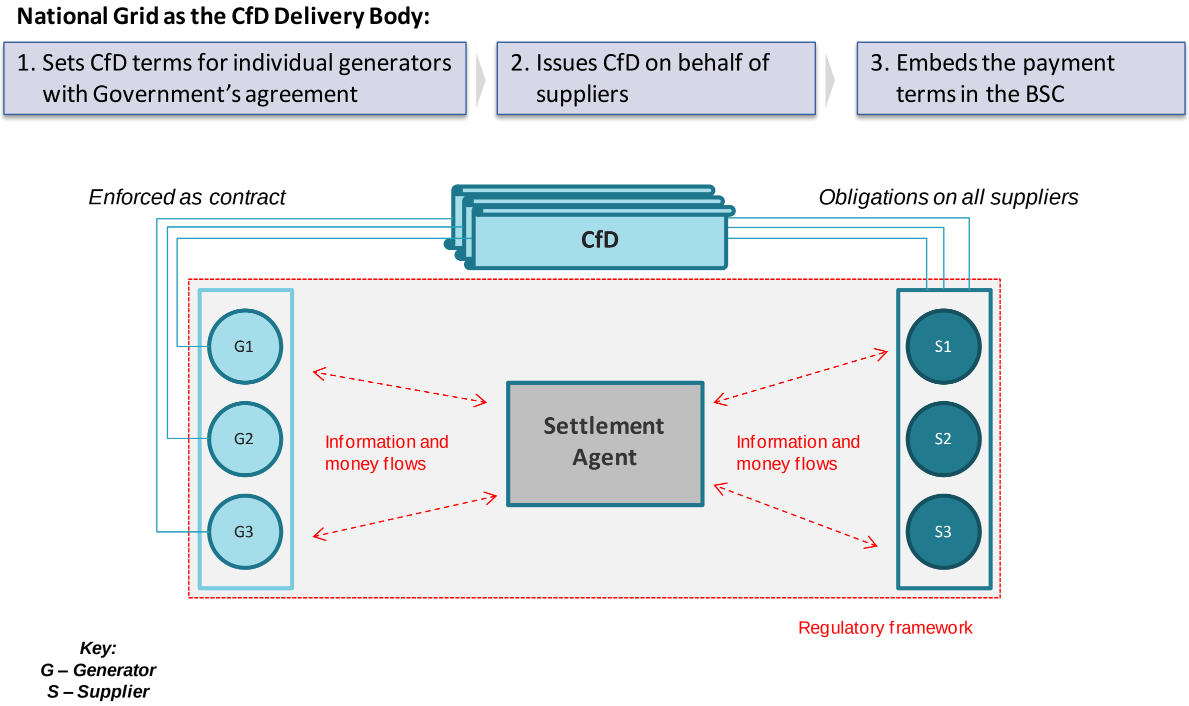
13. Government is minded to use arrangements similar to, and potentially integrated with, the Balancing and Settlement Code as the mechanism through which to bill and settle the payments for the CfD. Elexon is the company responsible for delivering the Balancing and Settlement Code and has a strong track record of

calculating and managing complex payments and settlements in a way that minimises the credit risk and impacts for both suppliers and generators.

Box 6: The Balancing and Settlement Code and Elexon

Elexon is the Balancing and Settlement Code Company (BSCCo) established under the provisions of the Balancing and Settlement Code (BSC). Its role is to administer the wholesale electricity balancing and settlement arrangements for GB. The settlement aspect relates to monitoring and metering the actual positions of generators and suppliers (and interconnectors) against their contracted positions and settling imbalances when actual delivery or offtake does not match contractual positions. Currently, all licensed electricity companies (i.e. all suppliers, distribution network operators, interconnector owners and transmission owners and most large generators) are obliged to sign the BSC under the conditions of their licence; other companies may choose to do so and this allows them to participate in the operation and development of the BSC arrangements.

Figure 16: National Grid as the CfD Delivery Body



14. The CfD will need to contain provisions setting out:
    - the settlement period (how frequently generators and suppliers will be required / entitled to make / receive payments);
    - the procedures that a settlement agent will follow in invoicing generators and suppliers and processing payments; and

- the procedures that a settlement agent will follow to reconcile any errors in the initial CfD invoices (this will mainly be a reallocation of supplier payments).

Settlement Period and calculation of payments

15. Payments under the CfD will be two-way. Thus, if the reference price is greater than the strike price for the relevant period, the generator will pay the amount of the difference in respect of the quantity generated for that period, and vice versa.

16. A more technical translation of these emerging proposals, to give a greater indication of what the relevant CfD terms might look like, is set out in Box 7.

Box 7: Calculation of CfD Payments

Calculation of CfD Payments

CfD Payments in respect of a CfD Settlement Period shall be determined as follows:

F7 $$CDP_{f,t} = (CSP_{f,t} – MRP_{f,t}) * CV_{f,t}$$

Where:

$CDP_{f,t}$	Is the Difference Payment expressed in Pound Sterling for a CfD Settlement Period;
$CSP_{f,t}$	Is the Strike Price in £/MWh applicable to that Settlement Period;
$MRP_{f,t}$	Is the Market Reference Price(s) in £/MWh applicable to that settlement period; and
$CV_{f,t}$	Is the CfD Volume in MWhs for the CfD Settlement Period

If in respect of a Settlement Period:

- If CDPf,t is positive (the Strike Price exceeds the Market Reference Price), then the CfD Suppliers must make the difference payment to the Generator.
- If CDPf,t is negative (the Market Reference Price exceeds the Strike Price), then the CfD Generator (which holds the CfD f) must make the difference payment to Suppliers.

Generator Net Difference Payments

Where a CfD Generator holds more than one CfD, the Net Difference Payment due to or owed by the CfD Generator in a CfD Settlement Period (t) is determined as follows:

F8 $$GNDP_{g,t} = \sum_{f(g)} CDP_{f,t}$$

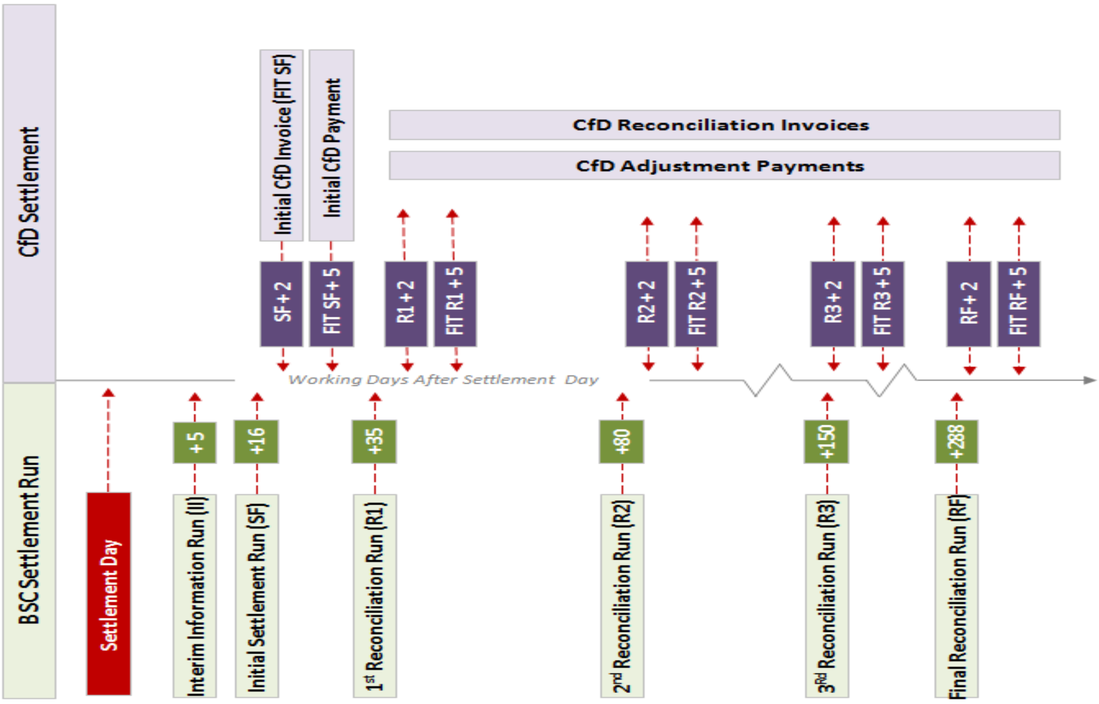
Where:	
$NDP_{g,t}$	Is the Net Difference Payments in respect of CfD Settlement Period t due to CfD Generator if F8 is positive or owed by the CfD Generator if F8 is negative; and
$\sum_{f(g)}$	Denotes the summation of Difference Payments under each CfD held by CfD Generator g.

Settlement Period

17. The EMR White Paper indicated a monthly settlement period following established industry processes akin to the BSC. The Government is now investigating options for shortening this period in order to reduce the collateral and credit requirements on electricity suppliers. However there are also benefits to longer settlement periods, in reducing administrative burdens and credit risk on smaller, independent generators and suppliers in particular. Government will aim to balance these considerations in coming to a decision.

18. As regards invoicing, payment and reconciliation schedules for CfDs, the Government is minded these will follow existing Balancing and Settlement Code processes. An example is provided in the figure below. Options will continued to be discussed with Elexon and other stakeholders.

Figure 17: Illustrative invoice and payment schedule



Allocation of supplier payments

19. In the proposed structure, all licensed electricity suppliers are collectively responsible for meeting payment obligations arising under the CfD. As such there is a need to ensure that this obligation is distributed proportionally across licensed electricity suppliers.

20. The Government has discussed this with Elexon and continues to examine different ways for the Settlement Agent to calculate the proportion of CfD payments to allocate to each supplier in each CfD settlement period. In principle, Government is minded that this proportion should reflect the relevant licensed supplier's gross demand for electricity in that period.

21. In relation to this, there is an established industry approach to measuring gross supplier demand for electricity. This is defined in the Balancing and Settlement Code ('Supplier Cap Take'). Whilst Government will continue to discuss possible metrics with stakeholders, the emerging view is that this represents the most likely metric for calculating the obligation on each licensed supplier in each CfD settlement period.

22. A more technical translation of these emerging proposals, to give a greater indication of what the relevant CfD terms might look like, is set out in Box 8.

Box 8: Allocation of Difference Payments

Allocation of Difference Payments

Each individual Supplier shall contribute to, or benefit from, difference payments in accordance with their share of the total Gross Consumption amongst all Suppliers in the relevant CfD Settlement Period (t).

The Net Difference Payments due to, or owed by, a Supplier (s) in respect of a CfD Generator (g) is determined as follows:

F9 $SNDP_{s,g,t} = -1 * GNDP_{g,t} * SCS_{s,t}$

Where:

$SNDP_{s,g,t}$	Is the Net Difference Payments in respect of CfD Settlement Period (t) due to the Supplier (s) in respect of the CfD Generator (g) if F9 is positive or owed by the Supplier to CfD Generator if F9 is negative;
$GNDP_{g,t}$	Is the Net Difference Payment due to or owed by CfD Generator (g), in accordance with F8
$SCS_{s,t}$	Is the share of Gross Consumption attributed to Supplier (s) in accordance with F10 such that $\sum_s SCS_{s,t} = 1$.

The (total) Net Difference Payments due to, or owed by, a Supplier (s) in a CfD Settlement Period (t) is therefore given by:

F9A $SNDP_{s,t} = (\sum_g -1 * GNDP_{g,t}) * SCS_{s,t}$

Determination of Supplier Consumption Share

A Supplier's share of Gross Consumption in a CfD Settlement Period (t) shall be calculated as follows:

F10 $SCS_{s,t} = SV_{s,t}/\sum_s SV_{s,t}$

Where:

$SCS_{s,t}$	Is the share of total Gross Consumption attributed to Supplier (s) in CfD Settlement Period (t)
$SV_{s,t}$	Is the sum of Gross Consumption attributed to Supplier (s) in BSC Settlement Periods (j) included in CfD Settlement Period (t) as determined under prevailing BSC rules:

F10A $SV_{s,t} = \sum_{j(t)} \sum_{i(s),j} SCT_{i,j}$

Where:

SCTi,j	Is the BSC Supplier Cap Take as defined under the BSC which captures (gross) Total Active Import by Supplier SP and BSC Settlement Period (as opposed to QM which includes embedded generation);
$\sum_{i(s),j}$	Denotes the sum of GSPs (i) associated with Supplier s in BSC Settlement Period j; and
$\sum_{j(t)}$	Denotes the sum of all BSC Settlement Periods included within the CfD Settlement Period.
$\sum_s SV_{s,t}$	Is the sum of $SV_{s,t}$ as defined above for all Suppliers.

Credit and Collateral

23. The CfD scheme effectively involves regular but variable payments flowing to and from generators and suppliers and in both directions. Credit risk to generators, for example, arises from losses as a result of supplier default that are not covered by the collateral lodged by that supplier, or 'unsecured' losses. This risk is driven by both the amount of collateral held and the time it takes for the payment flows to resume in the event of a supplier default.

24. As such there are potentially large credit risks to all CfD participants resulting from late payment or non-payment which if unmitigated would significantly increase financing costs, or may even prevent financing of projects. In order to manage this risk effectively, collateral requirements will be placed on participating generators and suppliers.

25. Under the current BSC arrangements, Elexon has a key role in monitoring parties' credit positions in order to adjust collateral arrangements accordingly. The Code allows for adjustments to be made if Elexon can provide evidence that the party is likely to default, or has bad credit history with BSC payments. If the party is non-compliant and building up debt, Elexon will recover that debt from the other parties until it is recovered, when it will be repaid.

26. The Government's current view is that a collateral requirement based on an estimate of likely settlement amounts of a CfD party due in a given trading period (possibly subject to a cap) could apply. A similar mechanism in the BSC has limited unsecured losses to 0.12% of turnover, despite a number of major parties going into liquidation. Collateral (held as either cash or letters of credit) is likely to be set at a level that covers the total liabilities of a party at any one point in time, as it is currently under the BSC. The level of the collateral held is affected by how often the payments are settled (e.g. daily or monthly settlement) and how far in arrears the payments are made.

27. Government will continue to discuss the nature of the collateral requirement with stakeholders and is mindful of the need to ensure that the costs of such collateral are manageable for smaller independent generators.

Mitigating against unsecured losses

28. Utilising the mechanisms like those under the Balancing and Settlement Code will reduce the amount of unsecured losses which may arise from a company entering administration, however there will still be a risk of unsecured losses and the larger risk of a big energy supplier becoming insolvent. There are a number of existing and recently introduced systems that will further protect both balancing payments and CfD payments, by ensuring that the impact from shortfalls is kept to a minimum.

Supplier of last resort (SOLR)

29. The SOLR process will facilitate the flow of CfD payments from consumers to generators in the event of supplier default. This process allows Ofgem to revoke the failed supplier's licence and appoint another supplier to take on its customers.

30. The SOLR arrangements have been tested several times over the last few years when small suppliers have failed. However, although the arrangements have worked well to date, experience has shown that it is unlikely that they would work as well in the event of a large supplier becoming insolvent because of the volume of customers involved.

Energy Supply Company Administration Regime

31. As an additional contingency measure to protect the market, the Energy Act 2011 provided for an energy supply company administration scheme which will ensure that, in the event of a large supplier becoming insolvent, arrangements are in place to ensure customers continue to be supplied with gas and electricity. This will be done as cost-effectively as possible until the company in difficulty is either rescued, sold or its customers are transferred to other suppliers.

Box 9: Energy Supply Company Administration Regime

The Energy Act 2011 provided the broad framework for energy supply company administration. The Government is due to consult on secondary legislation in summer 2012 to complete implementation. The energy supply company administration regime is expected to be fully implemented by spring 2013.

Should a large supplier fall into financial difficulty, the energy supply company administration regime will allow the Secretary of State or Ofgem to apply to the court for an energy supply company administration order. The court may make the order and appoint an energy administrator if the company meets the statutory tests for insolvency. The objective of the energy administrator would be to continue to supply customers as cost-effectively as possible until the company is either rescued, sold or its customers are transferred to other suppliers. The Government may provide financial support to the company in energy supply company administration, so that it can continue to operate normally. The energy administrator, as an agent of the company, would be required to comply with all the company's statutory and licence obligations, including making balancing and CfD payments.

The Energy Act also includes provisions to require the company to repay any financial support received from the Government. However, it is possible that the company may not be in a position to repay some of the funding. Therefore the Energy Act also empowers the Secretary of State to amend gas and electricity licences to introduce a cost recovery mechanism, so that any shortfall in the repayment of funding is socialised. The Government plans to consult on the proposed licence modifications and cost recovery mechanism in summer 2012. At present the envisaged cost recovery mechanism is similar to that already in place for Energy Administration – the special administration regime for energy network and distribution companies.

Processes within the BSC for recovering unsecured losses

32. In the BSC any unsecured losses are spread evenly across all generators and suppliers. Processes could be put in place for the CfD element of the Code whereby any unsecured losses are recovered from suppliers only (instead of being spread across all parties); this would eliminate this risk for generators. This would differ slightly from the mutualisation process currently used in the BSC. Government will continue to test these arrangements with Elexon and industry to assess whether they are appropriate.

Reducing barriers to new entry

33. The impact of this payment model on barriers to entry will be heavily dependent on how investors view both the counterparty risk and the complexity of the system. This payment model may appear more complex than a bilateral contracting model, however it uses a system, similar to the BSC, that most suppliers and generators are comfortable with.

34. All generators over 50MW[25] require generation licences to operate, which requires them to become signatories to the BSC. At present small-scale generators are not required to hold licences. Therefore this policy may have an additional regulatory and cost burden on smaller generators if they were required to sign up to a CfD code; however this could be mitigated by requiring those small-scale generators to be party only to settlement arrangements concerning CfDs rather than being required to be party to the BSC or other codes.

35. This payment model requires parties (both suppliers and generators) to post letters of credit or cash as collateral. Small suppliers are already expected to post letters of credit and cash under a number of other codes; this has been recognised as a burden for small suppliers because of the adverse impact it has on their cash-flows. The proposals for this policy would require the level of collateral to be higher than they would usually be under the BSC given the likely cost of CfD payment flows. More understanding of this issue is required and Government is working with Ofgem and suppliers to understand the consequences, however one mitigation could be to settle the payments more frequently or reduce the extent to which these payments are made in arrears. Government is minded to settle CfDs frequently with shorter arrears periods (where practicable) to reduce barriers to new entry.

[25] Broadly, but the requirements for generation licence exemptions are complex and not a general fixed MW limit for all circumstances (see the Electricity (Class Exemptions from the Requirements for a Licence) Order 2001 SI 2001/3270 as amended). An exemption can be subject to conditions.

Balance sheet impacts

36. The Government has considered whether the CfD is defined as a financial instrument (or derivative) for the purposes of accounting treatment, notwithstanding the fact it amounts to a set of statutory obligations. If it were treated as a derivative, it would be treated differently to the RO. If this were the case the lifetime cost of the CfD would be counted on both supplier and generator balance sheets and may be subject to FSA regulation.

37. Advice has been sought from the major accounting firms on this issue. Given that the obligation is linked to market share, it is not a long term liability as the obligation would fall away if a supplier exited the industry. Although it is not possible to provide a definitive view, it is therefore possible that CfD costs could be seen as a ‘production’ cost rather than a long term liability (as it would be if the supplier signed a CfD themselves). This is how the obligations under the RO are treated on supplier balance sheets.

F. ROUTES TO MARKET FOR LOW-CARBON INVESTMENTS

The Government's vision is for a competitive and efficient market that attracts the widest possible pool of investment to support delivery of renewable energy and carbon reduction targets. Independent renewable developers are likely to play an important role in this market. This section examines how the change in support mechanism for low-carbon generation may affect the incentives of suppliers and independent aggregators to purchase power from independent generators under long-term contracts (Power Purchase Agreements – PPAs), and the likely future development of the market.

The structure of the CfD should simplify risk management, however other factors could affect the availability of PPAs which independent generators rely on to secure investment. Further work will be undertaken in conjunction with industry to understand the current and likely future PPA market, and whether any interim steps are necessary to ensure there is a route to market for independent generators. As part of this, the Government will publish a Call for Evidence in June 2012 in order to ensure that the evidence base is fully developed.

1. For any power generation investment, investors will want to be certain that risks can be efficiently managed during the investment payback period. All generators need to manage a range of risks in order to operate effectively in the wholesale market. Those risks include:
    - **off-take risk** - the risk that power cannot be sold at an efficient price with a viable route to market;
    - **balancing risks** - the risk of not meeting the contracted position at gate closure and being exposed to the cash-out price. This can be mitigated by effectively forecasting output and trading on the intra-day market to avoid imbalance at gate closure;
    - **volume risk** - the risk that the total generation of the installed capacity falls short of what was expected;
    - **price risks** - the risk that the underlying wholesale price moves and the power that is generated does not achieve the expected price. The CfD proposals address the price risk for low-carbon generation through the provision of the top-up payment to the strike price (subject to achieving the reference price); and
    - **basis risk** - the risk of deviation between the market price achieved by the generator and the reference price in, for example, a CfD.

2. Market participants seek to manage these risks through their power trading strategies. Power can be traded directly in the wholesale market through bilateral contracts, brokered 'over-the-counter' trades or on exchange platforms. In these

cases an efficient liquid market is essential so that independent operators have clear price signals and are able to effectively manage trading risks. Work by Ofgem and industry to improve liquidity will play an important part in increasing competition and trading options.

3. However, there are some projects that will not be directly helped by these measures, in particular independent wind and other intermittent renewable technologies that currently rely on long-term off-take contracts, known as Power Purchase Agreements (PPAs), for their route to market and risk management. PPA terms vary, but typically the off-taker agrees to buy power at a discount to the prevailing wholesale price. The discount reflects the risks that the off-taker will manage on behalf of the generator, but the overall discount may be affected by the level of competition amongst PPA providers.

4. Reliance on PPAs reflects, in part, the scale of some generators' projects; including limited in-house trading capacity and the difficulties that individual wind projects face in managing their imbalance risks. The most important reason why independent generation projects rely on PPAs is likely to be that these projects rely on non-recourse project finance to part-fund the investment, which given the long length of financing typically requires the offtake and other risks to be entirely managed through a long term PPA with a credit-worthy counterparty. Whilst other routes to markets are theoretically available, in the majority of cases financiers will require a PPA.

5. Whilst current structures of PPAs vary, they typically fall into three types, which deal with risk in the following ways.
    - **Variable price PPA.** The PPA provider pays the generator the wholesale electricity price less a percentage discount that reflects the value of the risks that have been transferred under the PPA. Under the Renewables Obligation (RO) the generator is fully exposed to the price risk, while under the CfD the price risk is removed. This is expected to be the preferred type of PPA under the CfD, as generators will want to sell as close as possible to the CfD reference price.
    - **Variable price PPA with floor price.** As above, but the PPA provider guarantees a minimum price (either across all benefits – wholesale, ROCs and LECs – or more commonly today only for wholesale power), which reduces the price risk to the generator. This increased certainty for the generator is typically reflected in a greater percentage discount, reflecting the transfer of risk to the PPA provider. As the CfD provides a top-up to the strike price, PPAs with a floor price are not expected to be required in future.
    - **Fixed price PPA.** The generator would receive a constant price for any power produced. Under the RO, this approach transfers the price risk from

the generator to the off-taker. Fixed price PPAs offer stability but the degree of risk transferred is reflected in the price specified in the PPA which would be significantly lower than the average market price. Government has been told that there is less appetite amongst utilities to offer long term fixed price PPAs. Generators are not expected to seek fixed price PPAs under the CfD, as breaking the link to the reference price would leave them with a variable top-up and potentially exposed to paying back more than they received from the PPA if the reference price went above the strike price.

PPAs and the CfD regime

6. Some developers have suggested that the move from the RO to CfD is likely to undermine their ability to secure PPAs because suppliers will no longer be under an obligation to source renewable electricity. Whilst the removal of the obligation is likely to be one of many factors influencing supplier attitudes to structuring PPAs, the Government does not agree that the proposed change in support mechanism presents a fundamental and insurmountable barrier to the development of a viable PPA market under the CfD. In time a competitive market should provide bankable routes to market for independent generation projects.

7. The Government believes suppliers and independent aggregators will continue to offer PPAs as there will still be commercial opportunities in doing so:
    - the large vertically integrated companies and independent aggregators can manage imbalance risk more efficiently than an independent generator (because aggregate forecast inaccuracies will be reduced across their larger portfolio and they are able to use their trading capabilities to further reduce imbalance through the intra-day market);
    - the main electricity suppliers are short on power overall and will need to source additional volumes to meet their demand – this can be done either through the wholesale market or by contracting with independent generators through PPAs;
    - there is an incentive to offer PPAs linked to the reference price to hedge price risk arising from suppliers' obligations to pay the CfD top-up payment in proportion to their market share; and
    - possibilities for cash-out reform (such as a pre-gate closure balancing market) could reduce the costs of managing balance risk in the longer term[26].

8. The Government believes that alongside the development of a more liquid and competitive market the CfD offers the potential for PPAs to be simpler, more

[26] http://www.ofgem.gov.uk/Markets/WhlMkts/CompandEff/CashoutRev/Documents1/electricity-cash-out-SCR.pdf

transparent and potentially offer better terms, mainly due to the simplification of risk management under the CfD. This document has provided more certainty around the reference price and the ability to trade the reference price to minimise basis risk. PPAs for intermittent generation with a CfD are therefore expected to be variable PPAs linked to the day-ahead price.

9. The reduction in price risk compared to fixed-price or floor-price PPAs, along with the removal of risks associated with the ROC cash-flows, could lead to a reduction in the overall discount. Energy-only PPAs could also be more attractive to independent aggregators as there will no longer be a requirement to monetise the ROC. Removing this barrier to new market entrants may therefore lead to a more competitive market[27]. However, the Government recognises there may be a risk that it takes time for independent aggregators to be in a position to offer investable PPAs and for a fully competitive PPA market to develop. Adequate levels of competition will be essential if the benefits of greater transparency, better terms and lower discounts in PPAs are to be fully realised.

10. Developers have said that they are finding it increasingly difficult to attract PPA offers on suitable terms. Factors affecting this may include:
    - liabilities assumed in long term contracts by PPA providers being recognised on balance sheets or by ratings agencies, which could put a company's credit rating at risk;
    - an increasing proportion of intermittent generation on the system will lead to uncertainty of the costs of balancing in the future, and requires more active trading and higher collateral requirements for hedging. Possible changes to the balancing mechanism will also add to this uncertainty;
    - large vertically-integrated companies with a Renewables Obligation to meet increasing the size of their own wind and RO-eligible portfolios and thereby seeing a route for meeting their obligation through their own generation in the coming years;
    - the lack of liquidity and forward trading that damages price formation and investment signals, and may be limiting participation from independent aggregators; and
    - limited competition due to the small number of credit-worthy PPA counterparties that satisfy external debt providers.

11. The Government is aware, however, that independent aggregators do play a role in the market and discussions with market participants indicate that a number are seeking to grow their businesses or enter the market for the first time.

[27] Under the Renewables Obligation a supplier is required to monetise the ROC, and although there is no requirement for power and ROCs to be sold together, in practice it is simpler for a generator to agree one PPA that covers both. As such the CfD mechanism is likely to enable independent aggregators to compete more effectively in the PPA market and could help increase competition.

12. The Government believes that a competitive market should provide efficient routes to market for independent generation projects and wants to see a stronger, more competitive, PPA market that can underpin these investments. A number of market participants have said that the Government may need to intervene to ensure that independent developers have greater confidence that they will have an efficient route to market during the transition to the CfD regime. The Government recognises that it may take time for the market to develop, and believes that more evidence is needed to ensure that the extent and nature of the issues in the current and likely developments in the future PPA market are fully understood.

13. The Government will continue with investors, independent generation developers, potential PPA providers and Ofgem to ensure that the evidence base is fully developed, including:
    - evidence of the issues related to the current PPA market including the levels of competition, discounts and risk transfer;
    - evidence of the impact that changing conditions in the PPA market are having on investment decisions, the level of return and the required levels of debt and equity;
    - views on the likely development of the PPA market in the transitional period from the RO to CfDs, and then under the CfD only from 2017;
    - evidence of the barriers to a competitive market; and
    - options, including market-led solutions, that may be available to remove or reduce those barriers and to ensure a competitive and efficient PPA market.

14. As part of this process the Government will issue a Call for Evidence in June 2012 to examine the issues outlined above, setting out understanding of the issues, the evidence that is needed to move forward, and outlining initial options that may address market concerns.

G. WHOLESALE MARKET LIQUIDITY

A liquid market for electricity is an important factor underpinning the operation of CfDs, in ensuring an efficient, competitive market and setting a reliable reference price. There have been some positive developments over recent months, particularly in the day ahead market. However the Government believes further measures are needed to enhance energy market competition and transparency, and will work with Ofgem and industry to ensure liquidity strengthens.

1. Poor wholesale market liquidity is a significant barrier to entry to the electricity generation and supply markets. Poor liquidity may distort investment and operational signals, and prevent market participants from buying and selling energy at the scale and in the timescales they need in order to manage their risks effectively. In the context of EMR, a liquid market is important in order to support investment diversity, to ensure that CfD strike prices are established on the basis of an efficient competitive market, and to provide robust reference prices that reflect supply and demand fundamentals.

2. Ofgem identified a number of possible reasons for low liquidity, including: the role of vertically integrated[28] companies who may have less need to trade and are able to hedge[29] between their supply and generation activities; limited interconnection; the prevalence of the GB gas market; and the rise in credit and collateral requirements following the collapse and exit of Enron and others from the market in 2001/2[30].

3. There have been some positive developments since the EMR White Paper, in particular commitments by some large vertically integrated companies to trade minimum volumes through the N2Ex Day Ahead Auction[31]. Increased volumes in these markets could have the effect of strengthening reference prices. Both the N2Ex and APX exchange platforms are now trading clip sizes of 0.1MW that may meet the needs of smaller generators and suppliers, and N2Ex has launched a

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[28] Where one supply group owns two or more parts of the energy supply chain. For example, where the same supply group owns generation capacity and also supplies energy to the retail market.
[29] 'Hedging' refers to making some kind of investment, with the objective of reducing exposure to (short-term) price movements in an asset already held. Normally, a hedge consists of taking an offsetting position in a related asset and can be either financial or physical
[30] http://www.ofgem.gov.uk/Markets/WhlMkts/CompandEff/Documents1/Liquidity%20in%20the%20GB%20wholesale%20energy%20markets.pdf
[31] SSE committed to trading all of their electricity supply and demand in the day ahead market by the end of 2011 "(subject to market conditions and costs)" - http://www.sse.com/PressReleases2011/WholesaleElectricityPriceTransparency/
E.ON committed to trade in excess of 30% of their generation through the N2Ex day ahead market - http://pressreleases.eon-uk.com/blogs/eonukpressreleases/archive/2012/01/04/1774.aspx
Scottish Power committed to trade in excess of 30% of their generation through the N2Ex day ahead market by 1st March 2012 - http://www.scottishpower.com/PressReleases_2271.htm

futures market that could support hedging and risk management. National Grid is addressing the fact that liquidity is currently split between the two exchange platforms (N2Ex and APX) by developing a GB 'Virtual hub' that will provide a single day ahead reference price to facilitate near-term market coupling, while retaining the benefits of competition between platforms.

4. In order to address the problem of poor forward market liquidity Ofgem has published for consultation proposals for a Mandatory Auction of 25% of large vertically integrated companies' generation output[32]. Ofgem has set out an indicative list of peak and baseload products spread over the forward markets (front month to three years ahead).

5. The Government would like to see a step change in power market liquidity. Whilst recent developments in the day ahead market have been positive, the Government believes that further measures are needed in order to enhance electricity market competition and transparency. Steps to strengthen the forward markets and to sustain developments in the day ahead market are likely to be particularly important. The Government would like to see additional commitments from all market participants to increase day ahead and forward market liquidity and price robustness. The Government will work with industry and Ofgem to ensure that liquidity strengthens, and will act if necessary where barriers to entry are not addressed through these measures.

[32] http://www.ofgem.gov.uk/Markets/RetMkts/rmr/Documents1/Liquidity%20Feb%20Condoc.pdf

H. DEVOLUTION AND INTERNATIONAL

The UK Government is fully committed to ensuring that the Devolved Administrations are engaged in a meaningful way during the development of EMR arrangements, whilst fully respecting the existing devolution settlements. For ease of reference this section signposts the various areas in the annexes which have particular relevance to the Devolved Administrations. These sections detail the variations of the instrument within each respective Devolved Administration and the impacts this will have on the System Operator and EMR wide. This section also flags the possibility of opening the CfD to non-UK based plant if a decision is made to do so.

Devolution Principles

1. The key objective is to ensure an attractive investment environment for electricity generation in all parts of the UK. The principles by which the EMR arrangements have been agreed are:
   - maximum coherence across the EMR package as a whole and across the UK;
   - the Devolution settlements of each administration must be respected; and
   - close working and collaboration with the three Devolved Administrations to ensure full consideration of Devolved Administration issues, through ongoing engagement at Ministerial level and formal and informal working between Governments.

2. Devolution issues are discussed in detail in the Electricity Market Reform policy overview document and Annex A (EMR Institutional Framework). However, there are also additional references to how particular aspects of EMR operate in relation to the Devolved Administrations within:
   - The price setting section of this annex (section A).
   - CfD Terms – post commissioning section of this annex (section D).

Projects based outside of the UK

3. CfDs may also be used to support generation that is located outside of the UK should the Government make the decision to do so. Before taking that decision, consideration would be given to how the CfD could apply to low-carbon generating plant located outside of the UK. Although the UK committed to take the necessary powers to enable the Renewable Energy Directive flexibility mechanisms in the Renewable Energy Roadmap, the ultimate decision on whether to use them will depend on whether trading offers a cost effective means to meet the 2020 target for renewable energy, and decarbonisation targets. This decision will also be

informed by the DECC Renewable Trading Call for Evidence[33] issued on 26 April 2012.

[33] http://www.decc.gov.uk/en/content/cms/consultations/trading/trading.aspx

I. NEXT STEPS

Engagement opportunities

1. The Government welcomes the opportunity to engage with interested stakeholders to ensure that the proposals put forward in this document are balanced and workable. Engagement with industry will take place through bilateral meetings, workshops and expert group meetings. In addition written feedback on proposals would be welcome via email.

Expert groups

2. As part of stakeholder engagement a CfD expert group has been established. The Expert Group is comprised of industry experts and a consumer group representative and will play an important role in testing and improving policy proposals. This Expert Group will complement other forms of stakeholder engagement, such as meetings with trade associations and bilateral meetings, and will be run by the CfD design team. A summary of the group meetings will be published on the website after each meeting. For further details about the CfD expert group please contact Laura.Blizzard@decc.gsi.gov.uk.

Broad timeline

3. This Operational Framework is a draft model, and as such Government is open to discussion on its contents. Government anticipates making firm decisions by the autumn in order to inform the price discovery process and the FID enabling work. These decisions will be subject to Parliamentary approval through the Energy Bill or associated secondary legislation.

4. Over the summer the Government intends to undertake further analysis and hold discussions with industry groups as outlined above. In addition the current thinking on terms will be developed into a full CfD. Government intends to begin the price discovery process for renewable CfDs in the autumn and will publish draft strike prices in mid-2013, providing visibility to enable investment decisions.

5. Further details on next steps and timings for developing the CfD are set out in the Indicative EMR Implementation Roadmap published alongside this document.