Annex A – List of respondents to December consultation

DECC received 274 responses to the December 2010 consultation on Electricity Market Reform, of which 13 are confidential, 18 are from individuals and 1 is anonymous. Consultation responses sent by the 242 respondents listed below will be available on the DECC website around the end of July.

Figure A.1: List of Electricity Market Reform consultation respondents.

2020 Renewables
2Co Energy
Advanced Plasma Power
Advanced Power Generation Technology Forum
AES Ballylumford and AES Kilroot Power
Aggreko
Agri Energy
Air Fuel Synthesis
Air Products
Alstom
AMEC
Anaerobic Digestion and Biogas Association
Aquamarine Power
arc21
Argus Media
ASDA
Association for the Conservation of Energy
Association of Energy Producers
Association of UK Coal Importers
ATH Resources
Atkins
AvVail UK
B9 Energy Offshore Developments and THETIS Energy (Joint Response)
Banks Group
BG Group
Biofuelwatch
Blizzard Utilities

Blue-NG
BOC
BP
British Ceramic Confederation
British Glass Manufacturers' Confederation
British Hydropower Association
British Sugar Group
BT
Calor Gas
Campaign to Protect Rural England
Carbon Cycle
Carlton Power
Caroline Lucas MP
CCS TLM
CE Electric UK
Centrica
Ceres Power
ClientEarth
Climate Change Matters and Transform UK (Joint Response)
CO_2DeepStore
CO_2Sense
Coal Forum
Combined Heat and Power Association
Committee on Climate Change
Confederation of British Industry
Confederation of Paper Industries
Confederation of UK Coal Producers
ConocoPhillips
Construction Products Association
Consumer Focus
Cornwall Development Company
Cornwall Energy
Costain
Country Land and Business Association
Covanta Energy
Croydon Council
Cumbria County Council

Department of Enterprise, Trade and Industry Northern Ireland
Deutsche Bank Climate Change Advisors
DimWatt
DONG Energy Power (UK)
Drax Power
Durham Energy Institute
E.ON
Ecotricity
EDF Energy
EDP Renováveis
EEF and UK Steel
Eggborough Power
EirGrid
Electricity North West
Electricity Storage Network
Element Power
ELEXON
eMeter Corporation
Endesa Ireland
Eneco Wind UK
EnergieKontor
Energy Curtailment Specialists
Energy Developments (UK)
Energy Industries Council
Energy Institute
Energy Intensive Users Group
Energy Services and Technology Association
EnerNOC
Environmental Services Association
ESBI International
European Federation of Energy Traders
Expansion Energy Limited
ExxonMobil
Fichtner Consulting Engineers
First Utility
Flexitricity
Food and Drink Federation

Fred Olsen Renewables
Friends of the Earth
Friends of the Earth Scotland
Gaelectric Electricity Storage
Gaia Power
Gas Strategies
Gazprom Marketing and Trading
GE Energy
Good Energy
Grantham Institute for Climate Change and Centre for Energy Policy and Technology, Imperial College (Joint Response)
Green Alliance
Greenpeace
GreenPower
GrowHow UK
Hampshire County Council
HES Biopower
HgCapital
Highlands and Islands Enterprise
Highview Power Storage
Independent Generators Group
INEOS Chlor
INEOS Manufacturing Scotland
Infinis
Institute for Security and Resilience Studies
Institute of Directors
Institution of Civil Engineers
Institution of Engineering and Technology, the Royal Academy of Engineering and the Institution of Chemical Engineers (Joint Response)
Institution of Engineers and Shipbuilders in Scotland
Institution of Mechanical Engineers
InterGen UK
International Power
Invesco Perpetual
Irish Wind Energy Association
Isle of Anglesey County Council
Isle of Man Government

John Muir Trust
J R Power
Kelda Group [and Yorkshire Water]
KiWi Power
KTI Energy
Lloyds Bank
London Analytics
Low Carbon Finance Group
Low Carbon Group
Low Carbon Innovation Centre, University of East Anglia
Macquarie Infrastructure and Real Assets (Europe)
Mainstream Renewable Power
Major Energy Users' Council
Marine Current Turbines
McGrigors LLP
MGT Power
Microsoft
Mineral Products Association
National Grid
National Offshore Wind Association of Ireland
National Rights to Fuel Campaign
New Earth Energy
Newcastle University, Sir Joseph Swan Centre for Energy Research
NIE Energy
Non-Fossil Purchasing Agency
North East Process Industry Cluster
North London Waste Authority
Northern Ireland Federation of Housing Associations
Northern Ireland Renewables Industry Group
Norton Rose LLP
Nuclear Free Local Authorities
Nuclear Industry Association
Office of Gas and Electricity Markets
Oil & Gas UK
Orchid Environmental and Hargreaves Services (Joint Response)
Partnerships for Renewables

Peabody Energy
Peel Energy
Poyry
Prospect
REG Bio-Power
REG Windpower
Regen SW
Regulatory Policy Institute
Renewable Energy Association
Renewable Energy Systems Limited
Renewables UK
Respect Energy
RLtec
Royal Bank of Scotland
Royal Institution of Chartered Surveyors
RWE npower
Scotch Whisky Association
Scottish and Southern Energy
Scottish Coal
Scottish Enterprise
Scottish Environment Protection Agency
Scottish Government
Scottish Industrial Advisory Group on Thermal Generation and CCS
Scottish Power
Scottish Renewables
Scottish Resources Group
Scottish Water
SeaEnergy Renewables Limited
Sheffield Forgemasters
Shell
Siemens
Smartest Energy
Statkraft AS
Statnett SF
Statoil
Summerleaze

Supporters of Nuclear Energy
Sussex Energy Group, University of Sussex
Tata Steel UK
Tees Valley Unlimited
Tesco
The Common Good Party
The Co-operative Group
The Crown Estate
The Green Company
Trade Union Congress
Trade Union Congress Clean Coal Task Group
UK District Energy Association
UK Energy Research Centre
UK Hydrogen and Fuel Cell Association
Ulster Farmers Union
Unison
University of Edinburgh
University of Exeter, Energy Policy Group
Utilita Electricity
Utility Regulator Northern Ireland
Vattenfall AB
Veolia Environmental Services
Viridian Power and Energy
Viridor Waste Management
Wärtsilä Corporation
Water UK
Welsh Assembly Government
Welsh Power
Wessex Water
West Coast Energy
Westinghouse
Wood Panel Industries Federation
World Coal Association
WWF (World Wildlife Fund)

Annex B – Further detail on the proposed design of the Feed-in Tariff with Contract For Difference

Introduction

B.1 This annex sets out the rationale behind the proposed design of the Feed-in Tariff with Contracts for Difference (FiT CfD). It presents a comprehensive overview of the principles that have informed our design proposals, our proposed approach to different generation classes, the basic structures of FiT CfD in each case, and areas for further work. Further information on the costs and benefits associated with the FiT CfD are set out in the accompanying Impact Assessment.

B.2 The proposals outlined below are still being refined, and different aspects of the proposed design are at different stages of development. Accordingly, this annex outlines those elements of the design that Government is minded to adopt (such as different contract structures for different generation types) as well as others which are at an earlier stage of development (including the contract volume for 'baseload contracts').

B.3 DECC will continue to engage with Ofgem, industry and other stakeholders in order to further develop these proposals prior to bringing forward legislative provisions early in the second session.

Design principles

B.4 The primary objective of the FiT CfD is to stimulate investment in low-carbon generation technologies at the lowest cost to the consumer. The proposed design needs to recognise and satisfy a number of other important objectives reflecting wider policy goals and market impacts. In many cases it is necessary to find an appropriate balance between different objectives. For example, the FiT CfD needs to strike a careful balance between the amount of risk removed from investors on the one hand, and the costs to consumers on the other. In summary, in addition to the high-level criteria set out in Chapter 2 of this White Paper, the key principles which have informed our proposed FiT CfD design are:

- **efficiency:** including promoting cost-efficient low-carbon investment; recognising that commercial and operational behaviour varies across different generation classes; and retaining normal commercial incentives for generators (and suppliers) to sell electricity in a way that best reflects their operational models;

- **cost to society:** including providing for an efficient allocation of risk between generators and consumers; mitigating the potential for windfall profits/excessive rents; and mitigating the risk of gaming and contract manipulation at the expense of the consumer;
- **barriers to entry:** including the need to ensure an open and competitive process for awarding contracts, and more widely to avoid arrangements which favour a particular corporate structure;
- **coherence:** including the need to ensure consistency between the FiT CfD and other elements of Electricity Market Reform, as well as parallel Ofgem reforms e.g. on wholesale market liquidity; and
- **practicality:** including the need to, as far as possible, enable contracts to adapt to a changing market environment (for example, including an in-built mechanism for revising the reference price to ensure it remains the best representation of market prices).

Tailoring the support mechanism to reflect the characteristics of different types of electricity generation

B.5 While a FiT CfD can be applied to all types of generation, the specific design needs to recognise the characteristics of the plant being supported by the instrument. We have distinguished between three classes of plant:

- **intermittent:** plant which has little or no control over when it generates or at what level of production (beyond a decision to be available or not) and for which fuel costs are not a consideration. This class therefore includes wind as well as other renewable technologies such as wave and solar;
- **baseload:** plant which operates at a constant level of generation, either for economic reasons or because the plant has limited ability to vary output at short notice to respond to shifts in demand. In addition to nuclear generation, this class may also include some biomass plant[1] and Carbon Capture Storage (CCS) plant; and
- **flexible:** plant which has the ability to control its output (within certain maximum and minimum parameters) and respond to shifts in demand in different timeframes. This class will in general be associated with variable fuel costs. Low-carbon technologies include biomass as well as, in the future, potentially CCS.

B.6 These different characteristics mean that the cost and benefits of different FiT CfD structures vary. Which reference price to use and whether to average the reference price (over a period of time) are the key design choices that affect the efficiency of the FiT CfD for different generation types.

1 Most biomass plant has the ability to vary output, but also has the ability to run baseload. They tend to choose to run baseload in order to maximise their revenue, i.e. an economic rather than technical choice.

B.7 The reference price is a key component of the FiT CfD as it is used (alongside the strike price) to determine the payments to be made under the FiT CfD. 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. This means that there are a number of aspects to consider in formulating a reference price, including:

- the market segment from which the reference price is drawn: this could be the spot, prompt (e.g. day-ahead) or forward markets[2], or a basket of some or all of these;
- the averaging period: in essence whether the prices taken from a given market segment should be used individually or averaged over a longer period, for example, taking the average of 30 consecutive day-ahead prices to form a one month average of the day-ahead price. Averaging in this way can provide an additional incentive on some generation types to operate optimally (see below); and
- the price source (the index of the electricity price on which the reference price is based): for the contract to function operationally, the data source must be robust and credible. In principle, the Government considers that FiT CfD for all generation types should include an in-built mechanism for revising the reference price to ensure it remains the best representation of the market price for the relevant market segment.

B.8 There are two key effects to consider before determining whether to average the reference price:

- averaging the reference price provides strong incentives for generators to carry out maintenance at the right time and ensure plant is generating when prices are higher – this is a signal that baseload can respond to, but the maintenance schedule for intermittent plant is already largely driven by other factors such as wind patterns. Therefore, the efficiency benefits of averaging are significant for baseload plant but not for intermittent; and
- averaging also creates additional risks for intermittent plant. Output from wind turbines tends to be correlated; this in turn means that high winds can drive electricity prices down and as such reduce wind generators' revenues. The scale of this effect depends on the amount of wind generation on the system, which in turn is driven largely by renewables targets. Generators cannot predict how much wind generation will be on the system in the future and therefore would find it hard to predict how the price they receive from the market relates to the average price; averaging therefore introduces risk for intermittent plant that is difficult for them to manage.

2 The spot market refers to the wholesale market for electricity that is traded for delivery on the same day, the prompt market refers to the market for electricity that is traded for delivery on the following day. The forward markets refer to markets for electricity that is traded for delivery at a future point, e.g. a month or a year later.

B.9 It is also important to recognise that a FiT CfD has the potential to influence a generator's commercial incentives and operational behaviour. In particular, in order to stabilise its revenues, a FiT CfD supported plant is likely to decide to sell its electricity in the market segment from which the reference price is sourced. The instruments will be less effective in catalysing investment in low-carbon generation if the generator does not feel confident that it can sell its output at a price which is at least reasonably close to the reference price. Selecting a market for the reference price that retains the normal commercial incentives on a generator to sell electricity in the way that best reflects its operational model also minimises the likelihood of market distortions.

B.10 For example, intermittent generation can forecast its output with a reasonable degree of accuracy a day ahead of delivery, so can be exposed to volume and price risk within this timeframe. However, beyond a short delivery timeframe, the level of output an intermittent plant will generate becomes increasingly uncertain. A reference price taken from a market for electricity to be delivered later than the following day would therefore expose the generator to increased risk. This would detract from investor attractiveness and increase cost of capital without providing any additional benefits to the power system or the consumer.

B.11 The Government is therefore minded to adopt different FiT CfD structures for intermittent and baseload technologies. These structures are summarised in the table below and then discussed further in the rest of this Annex. The FiT CfD structure for flexible technologies is at an earlier stage of development, however we describe one option below. This option broadly consists of a fixed payment to cover a generator's fixed costs combined with a one-way FiT CfD that is structured in a way that provides generators with an incentive to generate when the electricity price is greater than their marginal costs.

Approach to different generation types

Figure B1: Overview of proposed[3] Feed-in Tariff with Contracts for Difference design.

	Intermittent	Baseload
Contract Form	• Two-way FiT CfD	• Two-way FiT CfD
Strike price	• Annual inflation indexation[4]	• Annual inflation indexation • Minded not to include fuel indexation for biomass. To be confirmed for CCS.
Market Reference Price	• Day-ahead price • Choice of baseload or hourly prices • Not averaged over a longer period	• Year-ahead baseload price • Choice of price sources
Contract Volume	• Metered output	• To be confirmed, metered output or firm volume

Intermittent generation

Contract form

B.12 The proposed FiT CfD for intermittent generation adopts a two-way contract form. In other words, the generator:

- receives a top-up payment up to the strike price when the electricity (reference) price is below the strike price; and
- passes back revenues to the consumer when the electricity (reference) price is above the strike price.

B.13 The Government considers that this arrangement delivers the appropriate balance between providing long-term revenue certainty for the generator, while ensuring that consumers are not overcompensating developers.

Contract volume

B.14 The Government is minded to introduce a FiT CfD that pays intermittent low-carbon generators on the basis of their actual output (in MWh). For example, where a generator is due for payments under the FiT CfD (the strike price in the contract is higher than the market reference price), the payment received by the generator is based on the actual amount of electricity it has delivered over the period in question. Payments will only be made under the FiT CfD if the plant is generating electricity.

3 These proposals are subject to the final design of any capacity mechanism.

4 We recognise the need for investors to achieve a return reflecting real terms; a link between the strike price and a measure of inflation would remove the inflation risk of the investment.

B.15 This mirrors the current arrangements for intermittent generators under the Renewables Obligation. Given the inherent variability of intermittent generation, making payments based on a pre-agreed level of output (firm volume) would place a risk on generators that they could not effectively manage. Generators would have no way of ensuring their level of output matched the level specified in a firm volume contract. Making payments to intermittent generators based on availability or capacity could also remove the incentive on generators to find the best locations for their plants and would also require extensive monitoring.

B.16 The Government therefore considers that payment for metered output, the actual amount of electricity produced, is likely to be the most efficient way to bring forward the maximum amount of low-carbon electricity and also to encourage optimal siting decisions for new low-carbon plant.

B.17 However, we recognise the concerns raised by a number of stakeholders that payment for metered output does give rise to the prospect of negative prices for electricity in the future and the corresponding distortions that this creates[5]. As a wind generator could only receive payments under the FiT CfD if it generates, it could for example offer its electricity at its opportunity cost – the support level[6]. In other words a wind generator could sell its electricity at a negative price (pay a supplier to take it) up to the level of its support payment.

B.18 With more significant penetrations of wind generation and inflexible plant such as nuclear, it is conceivable that there will be a need to constrain wind. As set out in Chapter 6 of this White Paper, the Government is clear that there will increasingly be a need for balancing solutions such as demand side management, electricity storage (including from plug-in vehicles) and interconnection (which if all current proposals are realised could increase to 10 GW by 2020). All of these solutions will help to reduce the likelihood of negative prices through shifting demand to utilise output from wind farms when required.

B.19 The Government notes Poyry's 2009 study on the effects of intermittency,[7] which suggests that with significant levels of wind[8] and a range of balancing solutions in place, negative prices may only occur for around 70 hours a year in 2030[9]. However, the Government will give further consideration to the likelihood and impact of negative prices in the future and examine the case for taking action to either limit or prevent negative prices from occurring.

5 As intermittent generators choose to generate even when the electricity price is lower than their marginal costs.

6 The support level in this case refers to the difference between the strike price in the CfD and the market reference price.

7 Implications of Intermittency: A multi-client study. Pöyry Energy (Oxford) Ltd (2009)

8 Installed wind capacity of 43GW by 2030 providing around a third of total generation.

9 Based on an assumption of existing wholesale market arrangements and the continuation of the Renewables Obligation.

B.20 There are a number of potential approaches, including for example paying some intermittent generators on the basis of availability rather than metered output to prevent wholesale prices going below zero. The impact and likelihood of negative prices also needs to be considered in relation to the contract volume for baseload generation. This is discussed further below.

B.21 The Government is mindful of the possibility that the System Operator (SO) may increasingly need to take action to constrain wind power for grid balancing reasons. In such cases the generator would not receive payment under the FiT CfD for the volume that has been constrained. The Government is minded that for these periods intermittent generation should be paid under the FiT CfD on the basis of their availability (i.e. their declaration to National Grid prior to being constrained). In a future scenario with much higher penetrations of intermittent and inflexible generation it will be important that the SO is able to turn down generation at least cost to the system. It is likely that the SO would want to turn down intermittent generation before turning off nuclear plant (both on cost grounds and due to the time nuclear takes to start up again).

Reference price

B.22 The Government considers that the day-ahead market should be the market segment from which the reference price for intermittent generation is drawn. There are a number of reasons for this. First of all, the day-ahead market reduces the risk[10] that would be introduced if a market for a period further ahead were used. As noted above, intermittent generators are generally unable to forecast output with much accuracy until relatively close to the point of delivery and so longer dated options could lead to a mismatch between the price a generator receivess for its electricity in the market and the reference price in its FiT CfD.

B.23 A half hour ahead spot price would completely remove this risk, but generators would have no incentive to actively manage any of their output into the market, rather they would sell power very close to delivery which would increase system balancing challenges for the SO. In addition, the within-day market is characterised by buyers and sellers seeking to avoid exposure to the Balancing Mechanism, which means it is likely to be volatile and not a robust representation of the value of ‘prompt power’ across the industry.

10 This risk is sometimes referred to as ‘basis risk’. It is the risk that the generator achieves a price in the market which is lower than the reference price.

B.24 In contrast, the day-ahead market:

- is a market on which an intermittent generator should be able to confidently sell power, given existing wind forecasting techniques[11]; and
- is relatively liquid, already used extensively by intermittent generators, and provides clip sizes (volumes available to trade) which are small enough to meet the needs of smaller generators, while also providing sufficient depth for larger deals to be struck.

B.25 The Government recognises that there will be some inaccuracy between day-ahead forecasts and actual output delivered, but considers that this 'basis risk' should remain with the generator as it is unlikely to be particularly large and it provides an incentive for generators to adapt to manage it, for example by developing better forecasting techniques. In other European countries (for example, Denmark) that have applied either CfD or variants of Premium FiT with a link to electricity prices, the chosen reference price for intermittent generation is in general a day-ahead market price.

B.26 The Government considers that day-ahead prices should not be averaged over a longer period to generate a reference price for intermittent generation. As described above, this is because to do so would increase the revenue risk to generators, but not deliver the benefits (in terms of optimal maintenance and operating decisions) that should arise for other types of generation.

B.27 Finally, the Government considers that the price source (the market price index used to provide the reference price) should be the best representation of day ahead market prices at the time the FiT CfD is allocated to the generator.

Baseload generation

Contract form

B.28 The proposal for the FiT CfD for baseload generation is to adopt a two-way contract form. As is the case for intermittent generation, the principal reason for proposing this contract form is to protect the consumer from price scenarios in which the generator could receive significantly more revenue than required to deliver a commercial rate of return over the lifetime of the investment.

Contract volume

B.29 The Government has considered different options for determining the volume in the contract, of which the lead two are outlined below. The Government will continue to engage with Ofgem, industry and other stakeholders before coming to a firm view on this aspect of FiT CfD design.

11 See The State-Of-The-Art in Short-Term Prediction of Wind Power: A Literature Overview, 2nd Edition (2011) by Giebel et al. See also Alternative Trading Arrangements for Intermittent Renewable Power: A Centralised Renewables Market and Other Concepts (2010) by Hesmondhalgh et al.

B.30 The first option is to base the contract volume, as with intermittent generation, on metered output. This retains the advantages set out above in terms of linking the support payments directly to the actual amount of low-carbon electricity produced, and therefore directly to the generating plant itself. There are, however, concerns that this option could distort the 'despatch decisions'[12] of baseload plant and increase the likelihood of negative prices.

B.31 The alternative option is to base the contract volume on a pre-agreed fixed number of MWh ('firm volume'), as opposed to actual generation. The main advantage of a 'firm volume' contract is that the generator continues to base its decision on whether to generate (despatch) on the electricity price relative to its production costs, rather than in order to access a FiT CfD payment (which it will receive/pay regardless of whether it generates or not).

B.32 There are however potential risks with firm volume contracts for baseload generation. For example, if the strike price is above the reference price, consumers could be paying for plant that is not generating (for example a long-term forced outage of a nuclear plant).

B.33 The Government recognises that there are trade-offs between these two design options, and considers that further analysis is required to provide greater clarity on:

- the extent to which a metered output FiT CfD would genuinely distort the operating (despatch) decisions of, in particular, nuclear plant;
- the likelihood and impact of negative prices in the low-carbon transition;
- the extent to which a two-way metered output FiT CfD would affect the allocation of risks to CCS plant (see also section on fuel costs below); and
- the likelihood of portfolio generators using fossil fuel generation in order to meet obligations under a firm volume FiT CfD.

Reference price

B.34 The Government is minded to use the year-ahead market as the market segment from which the reference price for baseload generation is drawn. There are a number of reasons for this preference:

- year-ahead prices effectively represent an average of market prices across the year of delivery. As previously described, averaging prices to derive the reference price in this way sends a strong signal to baseload plant to carry out maintenance when market prices are low and ensure it is operating when prices are high; and

12 The decisions made by power plants on when and when not to generate.

- by selling electricity ahead of delivery, the generator is incentivised to ensure reliability. If the plant is not operating, the generator does not receive payments under the FiT CfD (in the case of metered output rather than firm volume), but more importantly they are exposed to the market price. This is because the generator has already sold power forward and is obliged to deliver this power. If the plant cannot generate, the generator has to buy power from elsewhere to meet this obligation. Evidently, the generator improves revenue by avoiding high priced periods for such repurchasing needs;
- using a year-ahead market retains the existing incentives for generators to sell ahead of delivery, which allows suppliers to meet the needs of their customers who are looking for longer-term stability. It also allows suppliers to smooth their purchasing costs; and
- using a forward market such as the year-ahead market would enhance liquidity[13] in that market, which may have benefits for small or independent suppliers.

B.35 The price source should be the best representation of year-ahead market prices at the time the FiT CfD is allocated to the generator. The Government notes that in the current GB market the longest contract, with adequate liquidity, is a season-ahead. Calendar contracts are now quoted more often in GB, but the market remains dominated by season-ahead. Therefore, for this FiT CfD an average of the summer and winter prices is likely to be most relevant as a reference price. An alternative option may be to use an average of the clearing prices of Ofgem's proposed Mandatory Auctions[14]. The Government will continue to discuss the merits of this approach with Ofgem.

Flexible generation

General

B.36 In order to largely decarbonise the electricity sector, it is likely that the future low-carbon generation mix will need to provide both firm baseload power to meet the core, steady demand for electricity, and also some flexible power to flex up and down in line with shifts in demand and to offset the intermittency of some renewables.

B.37 The Government considers that a different structure may be required to bring forward investment in flexible low-carbon plant that is likely to run at lower load factors than baseload. The Government's initial view is that in this case the FiT CfD should incentivise the generator to fully respond to short-term market signals, generate at times of high demand and turn down/off when demand is low.

13 A liquid market is one in which participants are able to quickly buy or sell a product without causing a significant change in its price and without incurring significant transaction costs.

14 http://www.ofgem.gov.uk/Pages/MoreInformation.aspx?docid=1&refer=Markets/RetMkts/rmr. See also the Impact Assessment that accompanies the White Paper for more information.

B.38 A FiT CfD for flexible plant may not need to be issued until some time in 2020s given the continued role played by conventional gas-fired generation. The Government is not committing to introduce a FiT CfD for flexible plant at this stage but will continue to consider the optimum arrangements for this type of generation.

Contract form and volume

B.39 The Government recognises that a possible contract form for flexible generation is a one-way contract form with a contract volume based on firm volume rather than metered output.

B.40 Under a one-way FiT CfD, a generator receives a fixed payment (for example at the start of each month or year) to cover its fixed costs. The generator then has an incentive to generate only when the electricity price is greater than its marginal cost[15] (i.e. when demand is high). This is achieved through the design of the one-way FiT CfD. The generator is required to pay difference payments to the institution if the power price exceeds the marginal cost of generation (the strike price in the contract). The generator would therefore cover its variable costs from the revenues it receives from selling its electricity – any excess profits it made from selling power would be returned to the institution.

B.41 There would be no incentive to generate when the price is lower than a generator's marginal cost because the generator does not receive any support payments linked to output (as for any generation plant that does not receive support).

B.42 One advantage of this contract form is that the generator is incentivised to operate at periods of high prices when the system is under stress, which is a requirement for plant operating in the mid-merit/peaking tranche of the merit order[16].

Reference price

B.43 In principle the reference price would be based on a short-term index[17] to ensure that the generator responds to short-term market signals and ensures security of supply. The Government will continue to engage with industry on this and alternative options.

15 This should result in efficient despatch.

16 Baseload generation is that used to meet continuous demand and non-baseload generation is brought in progressively as demand increases. Peak-load generation is used to satisfy short periods of maximum demand. Mid-merit generation is that which falls between baseload and peak.

17 Index of prices from the spot or prompt markets, for electricity that is traded for delivery on the same or following day.

Additional considerations

Carbon Capture and Storage demonstration projects

B.44 The Government is committed to demonstrating CCS quickly to encourage rapid investment and deployment, and is considering the best mechanisms for supporting CCS demonstrations. Budget 2011 set out that CCS demonstration support would come through general taxation. In line with this, taking into account impact on overall affordability, we are considering several funding options for providing financial support including potentially through the FiT CfD alongside other approaches.

B.45 We expect support for these early projects will need to be different to that for commercially-proven CCS and other low-carbon baseload options, given the additional risks involved with investment in CCS demonstrations.

B.46 In particular, these projects are likely to be less reliable and predictable. As a consequence there is greater revenue risk when compared to other low-carbon generation options if support is delivered through a FiT CfD based on output. We are therefore assessing the possibility of greater certainty of payment in the FiT CfD making up part of the support package for CCS demonstration projects. The Government will continue to engage with stakeholders on how best to support CCS demonstration projects.

Fuel costs for biomass and Carbon Capture Storage

B.47 For plant with variable fuel costs such as biomass or coal or gas for CCS, there is an option to adjust the level of support to compensate for fuel price fluctuations.

B.48 This is because, in contrast to other forms of low-carbon generation, biomass and CCS operators have a fuel price element to consider in their generation process. Unlike wind (which has free fuel) and nuclear (which has a low fuel input cost coupled with stability in that fuel price), biomass and CCS generators need to purchase fuel for the production of electricity. A two-way FiT CfD would prevent generators from recovering variations in the cost of fuel through the electricity market. Fuel prices can vary over the commercial life of a power station, and the Government acknowledges that this could present an appreciable risk to generators.

B.49 Linking the FiT CfD strike price (or possibly the reference price) to the fuel costs for these plants (so, for example, the strike price would rise as fuel costs rise and vice versa) would increase long-term revenue certainty for generators. As such it could mean that the FiT CfD strike price could be lower than if the fuel price risk were retained by generators.

B.50 However, there are also arguments against linking the FiT CfD strike price to fuel costs. As noted above, the Government is mindful of the need to provide for an efficient allocation of risk between generators and consumers. Linking the strike price to fuel costs would leave consumers (rather than generators) exposed to the risk of high fuel prices. In general the Government considers that generators are better placed than the consumer to manage this risk. In addition, not linking the FiT CfD strike price to fuel costs would enable better price comparison between different low-carbon technologies. It would not be possible to directly compare a strike price that fluctuates with fuel costs with another that does not.

B.51 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. As such the Government is currently minded not to link the two-way FiT CfD strike price to fuel costs for biomass.

B.52 For CCS, the Government recognises that the market circumstances may be somewhat different when it moves from demonstration to commercial deployment. It is not clear at this stage if CCS will be commercially deployed as baseload or intermediate load/flexible generation, which may affect the type of FiT CfD to be offered. The Government will therefore continue to consider the best arrangements for supporting commercial CCS, including the case for providing a link to fuel costs.

Payment for capacity as part of the FiT CfD

B.53 The Government will carefully consider the interactions between the FiT CfD and Capacity Mechanism in developing both mechanisms in a coherent and complementary manner. The Government will therefore consider including an element of payment for capacity within the FiT CfD.

Next steps

B.54 In addition to those areas already identified in this annex, the Government will develop further the design of the FiT CfD including the following:

- **settlement period:** the frequency with which payments are made/received under the FiT CfD;
- **contract duration:** the length of the contracts;
- **enforcement of contract obligations:** in order to ensure effective operation of the contract and that conditions associated with contract award are carried out to achieve the goals of Electricity Market Reform;
- **terms for credit and collateral:** the credit terms including requirements for security and credit-worthiness of the developer;
- **indexation:** the approach to linking the FiT CfD strike price to a measure of inflation to remove inflation risk from the investment; and
- **payment mechanisms:** the design of the mechanism or mechanisms for ensuring that generators can receive and make payments under the FiT CfD.

Annex C – Consultation on possible models for a Capacity Mechanism

Purpose of this consultation

The Government is seeking views on alternative approaches to a potential Capacity Mechanism for the GB electricity market.

Issued: 12 July 2011

Respond by: 04 October 2011

Enquiries to:

Matt Wieckowski
Department of Energy & Climate Change,
4th Floor, Area D
3 Whitehall Place,
London, SW1A 2AW
Tel: 0300 068 5101
Email: DECC.capacity.mechanism@decc.gsi.gov.uk

Command number: 8099, URN 11D/823 – Planning our electric future: a White Paper for secure, affordable and low-carbon electricity.

Territorial extent:

The Capacity Mechanism proposed here would be GB-wide. However, further development of the scheme will include discussions with the Welsh Government and Scottish Government to determine how the Capacity Mechanism should apply in their jurisdictions. The scheme set out here would not apply in Northern Ireland.

How to respond:

Direct responses to the questions posed will be most useful, though comments are welcome on any aspect of the proposals set out in this annex. Evidence to support your answers will be particularly helpful, but if including any long reports as part of your response, please identify the relevant sections.

Responses are welcome by email or post to the addresses above.

Additional copies:

You may make copies of this document without seeking permission. An electronic version can be found at http://www.decc.gov.uk/consultations.

Other versions of the document in Braille, large print or audio-cassette are available on request. This includes a Welsh version. Please contact us under the above details to request alternative versions.

Confidentiality and data protection:

Information provided in response to this consultation, including personal information, may be subject to publication or disclosure in accordance with the access to information legislation (primarily the Freedom of Information Act 2000, the Data Protection Act 1998 and the Environmental Information Regulations 2004).

If you want information that you provide to be treated as confidential please say so clearly in writing when you send your response to the consultation. It would be helpful if you could explain to us why you regard the information you have provided as confidential. If we receive a request for disclosure of the information we will take full account of your explanation, but we cannot give an assurance that confidentiality can be maintained in all circumstances. An automatic confidentiality disclaimer generated by your IT system will not, of itself, be regarded by us as a confidentiality request.

We will summarise all responses and place this summary on our website at www.decc.gov.uk/consultations. This summary will include a list of names or organisations that responded but not people's personal names, addresses or other contact details.

Quality assurance:

This consultation has been carried out in accordance with the Government's Code of Practice on consultation, which can be found here:
http://www.bis.gov.uk/files/file47158.pdf

If you have any complaints about the consultation process (as opposed to comments about the issues which are the subject of the consultation) please address them to:

DECC Consultation Co-ordinator
3 Whitehall Place
London SW1A 2AW
Email: consultation.coordinator@decc.gsi.gov.uk

C.1 Introduction

C1.1 Chapter 3 of this White Paper sets out the Government's view of the security of supply challenges faced in the GB market, and concludes that a Capacity Mechanism is required to ensure future security of supply[1].

C1.2 This position builds on that set out in the Electricity Market Reform Consultation Document[2], where the Government indicated a preference for a targeted Capacity Mechanism under which an obligation would be placed on a central body to maintain a set capacity margin.

C1.3 Respondents to the consultation set out a wide range of views. A significant number expressed strong concerns about the introduction of a targeted mechanism.

C1.4 To address the issues raised, the Government is seeking views on alternative approaches to a potential Capacity Mechanism:

- a **targeted mechanism**, with a proposed model of a **Strategic Reserve**, a development of the lead option from the consultation document which aims to mitigate concerns raised by stakeholders. This comprises centrally-procured capacity which is removed from the electricity market and only utilised in certain circumstances; or

- a **market-wide mechanism** in the form of a **Capacity Market**, in which all providers willing to offer capacity (whether in the form of generation or non-generation technologies and approaches such as storage or demand side response (DSR)) can sell that capacity; and the total volume of capacity required is purchased. There are several forms of Capacity Market, depending on the nature of the 'capacity' and how it is bought and sold. In particular, there are a number of ways to purchase capacity – including through a central auction or a supplier obligation. One form of a Capacity Market is a **Reliability Market**, for which, given its innovative nature, we are keen to gain stakeholder feedback and have included detailed design questions. We recognise that there are other forms of market-wide mechanism, such as those which set price in order to incentivise sufficient volume (Capacity Payments), and these remain under consideration.

C1.5 For reference, Figure C1 shows the kinds of Capacity Mechanism that we discuss in this annex, and the Capacity Payments mechanism discussed in the Electricity Market Reform Consultation Document. Under a Capacity Market, there are a number of ways to purchase capacity – including through a central auction or a supplier obligation.

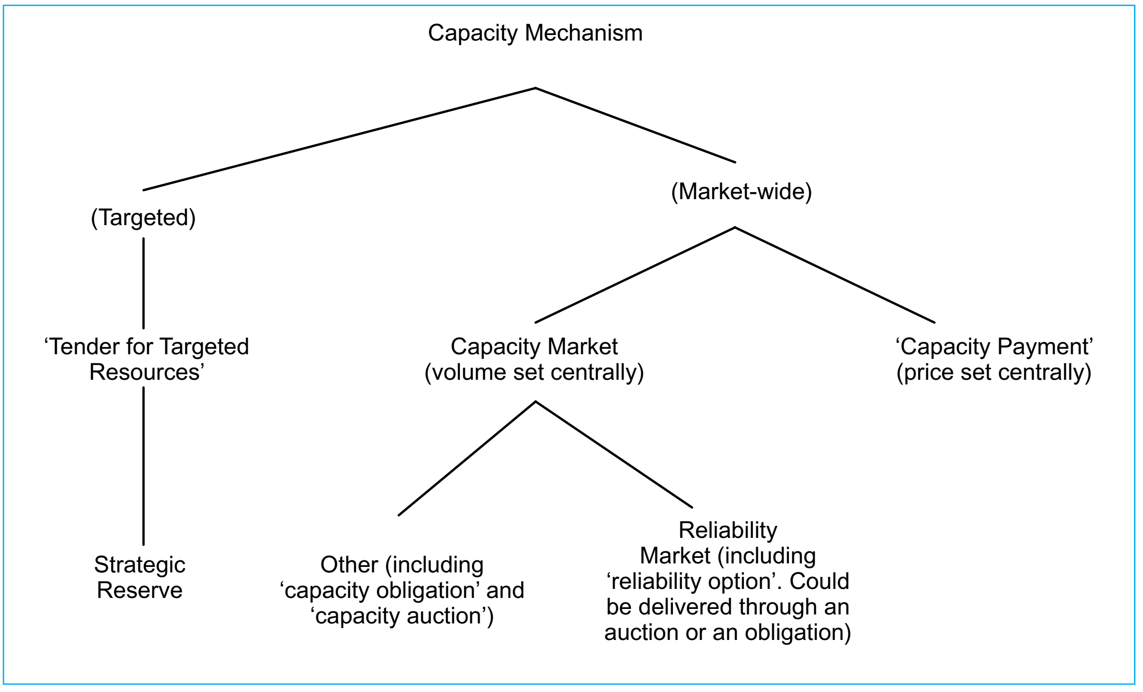
C1.6 This annex sets out the detail of the Strategic Reserve and Capacity Market options. Sections 2 and 3 describe some of the design

1 As noted in Chapter 3 of this White Paper, a Capacity Mechanism is intended to address the challenge of ensuring resource adequacy (i.e. that there is sufficient reliable and diverse capacity to meet demand, for example during winter anti-cyclonic conditions where demand is high and wind generation low for a number of days).

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

considerations for each, and some international examples are included in Section 4. The options are then compared against a set of criteria in Section 5. A number of questions on areas where we are seeking stakeholders' views are included throughout, and while responses to these would be particularly helpful, comments are welcome on any aspect of these proposals. The questions are compiled in Section 6.

Figure C1: Possible models for a Capacity Mechanism



Notes:

The Capacity Mechanism types in inverted commas are those proposed in the December consultation document.

Under a Capacity Market, one distinction is what is bought and sold (i.e. a regulatory definition of capacity or a reliability contract). Another distinction is how the capacity is bought and sold, which could be through a central auction and/or a supplier obligation.

C.2 Targeted Mechanism: Strategic Reserve

Overview

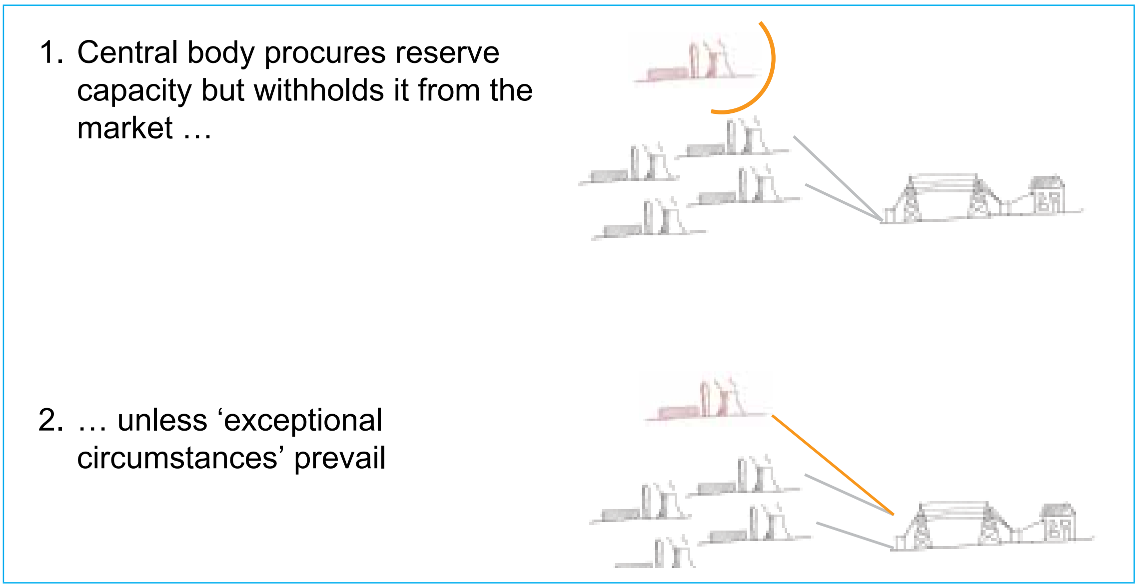
C2.1 The Electricity Market Reform Consultation Document included a preference for a 'tender for targeted resource'. We have further refined this to a Strategic Reserve, as opposed to other approaches such as an extension of Short-Term Operating Reserve (STOR), as the most suitable targeted mechanism to address the security of supply challenge.

C2.2 The key elements of this approach are:

- a central determination would be made of the required reliability level and whether the market is likely to deliver this;
- if no shortfall is expected, no additional capacity would be procured;
- where there is a shortfall in forecast reliability, a central body would be charged with competitively procuring the necessary volume and mix of Strategic Reserve; and
- the Strategic Reserve would be withheld from the electricity market and would only be despatched when prices rise above a certain level – the despatch price. The despatch price would be set above the highest long-run marginal cost in the electricity market, but below the theoretical value to the GB economy of preventing blackouts – Value of Lost Load (VoLL)[3]. It would therefore constitute a cap on market prices[4].

C2.3 Figure C2 shows how a Strategic Reserve would operate to ensure a capacity margin.

Figure C2: Strategic Reserve mechanism in practice



3 VoLL is the theoretical value to the GB economy of preventing blackouts. It is the electricity price at which an average consumer would rather be cut off than continue paying.

4 The proposal for price setting is set out in more detail in 'Setting the reserve despatch price'.

Addressing stakeholder views

C2.4 A number of stakeholders reported concerns with the tender for targeted resource Capacity Mechanism described in the Electricity Market Reform Consultation Document. We have sought to mitigate these concerns in the proposed design of the Strategic Reserve. Figure C3 outlines stakeholder concerns and summarises how the proposed design of a Strategic Reserve aims to address them.

Figure C3: Stakeholder concerns and the Government's proposed mitigation approach

Concern	Mitigation
Market distortion Respondents felt that a tender for targeted resource would: • undermine effective operation of the market; • reduce incentives for investment; • lead to an ever-increasing need for reserve; • not feed into wholesale market electricity prices, thus preventing prices correctly rising at times of system stress when the reserve is used; and • have a despatch price that would be lowered following pressure at times of system stress/high wholesale prices.	To address these concerns we have developed a Strategic Reserve with the following proposed features: • to minimise electricity market plants being displaced from the merit order, Strategic Reserve would not be available to the electricity market and would be despatched at a fixed despatch price which is high enough above the highest long-run marginal cost in the electricity market to minimise distortion, but below VoLL; • the despatch price would have a defined change process to ensure any change is properly considered and not subject to short-term pressures; • Strategic Reserve could be included in the cash out calculation, thus allowing cash out prices to correctly rise to reflect the cost of using Strategic Reserve when it is used[5]; and • the operation of Strategic Reserve would be reviewed periodically. The review would consider the impact of Strategic Reserve on the electricity market and whether the fixed despatch price is correctly set.

5 Cash out exists to reflect the cost of balancing the electricity system onto organisations which are out of balance at that point. In a normally functioning electricity market we would expect cash out prices to rise when the system is under stress (i.e. when there is a large difference between supply and demand) and the costs of balancing the system are greater.

Concern	Mitigation
Transparency and independent oversight A tender for targeted resource needs to be administered by a body independent of commercial and political conflicts, and which works to a transparent and stable methodology.	The procurement and despatch functions would be regulated activities with the legislation setting out how these functions should operate. The Strategic Reserve methodology would be described in legislation allowing market participants to understand how and when Strategic Reserve would be used.
Contract flexibility A tender for targeted resource may be inflexible and lock customers into paying for reserve regardless of need.	The reserve procurement functions would procure the most efficient Strategic Reserve. This would include considering the appropriate length and structure of contracts.
Eligibility and innovation A tender for targeted resource may fail to recognise the importance of resource flexibility, and may not incentivise innovative and/or non-generation approaches (e.g. DSR, interconnection).	The Strategic Reserve procurement function would procure a mix of Strategic Reserve based on criteria designed to allow flexible capacity, including DSR, storage and interconnection, providing it has the necessary physical characteristics (e.g. ramp-up and down rates).

Question 1: Does this table capture all of your major concerns with a targeted Capacity Mechanism? Do you think the mitigation approach described will be effective?

Setting the required level of capacity

C2.5 Each year a determination would be made centrally of the required level of reliability – the percentage of time that the electricity market is expected to have adequate resource to meet demand. This assessment would include consideration of:

- the level of electricity demand over the next four years (considering peak demand and demand variability);
- the level of generating capacity over the next four years (considering peak generation, intermittency and variability); and
- the likely cost of providing different levels of reliability (over and above that which the market will provide).

C2.6 To assist this central assessment, the Gas and Electricity Markets Authority (GEMA) would provide an annual report on security of electricity supply[6]. Primary legislation is being sought through the current Energy Bill to enable this.

6 Ofgem is governed by GEMA, which consists of non-executive and executive members and a non-executive chair.

Procuring the necessary reserve

C2.7 Once the level of reliability has been set, and a determination made that the market will not deliver this level of reliability, responsibility for procuring the necessary reserve would sit with the Strategic Reserve procurement function.

C2.8 The procurement function would consider the required reliability level and the shortfall which Strategic Reserve would need to fill, and would procure an appropriate volume and mix through a competitive tender process.

C2.9 When procuring Strategic Reserve, the procurement function would need to consider the lead time between the procurement of Strategic Reserve and its availability (particularly for generation that has yet to be constructed) and the appropriate contract duration. We envisage that the four-year forward looking reliability level would provide adequate time for the procurement function to procure new plants if required. The procurement function would have the scope to set the appropriate contract length based on the requirements for Strategic Reserve[7].

Question 2: How long should the lead time for Strategic Reserve capacity procurement be and why?

Question 3: Should the length and nature of contracts procured by the Strategic Reserve procurement function be constrained in any way?

Criteria that providers of Strategic Reserve would need to meet

C2.10 Strategic Reserve is focused on ensuring there is sufficient resource to meet extended periods of high demand and/or low generation, whereas National Grid would retain responsibility for operational short-term security through existing arrangements (such as STOR) (though the relationship between the mechanism and STOR would need to be carefully considered).

C2.11 The procurement function would need to consider appropriate criteria to ensure the desired mix of Strategic Reserve. The criteria would apply to all forms of reliable capacity (including DSR and storage), both existing and proposed. We would welcome your views on the criteria that providers of Strategic Reserve would be required to meet. Examples of potential criteria include:

- ramping rates – rate at which capacity can change its generation or demand;
- availability fees – the fixed costs paid to generation and non-generation for being available;

7 More discussion on contract lengths is included in 'How far ahead should contracts be purchased?' in Section 3: 'Capacity Market'.

- availability periods – period capacity is available; and
- length of sustained running – sustained period capacity can be run.

Question 4: Which criteria should providers of Strategic Reserve be required to meet?

The role of demand side response, storage and other non-generation technologies and approaches

C2.12 Non-generation technologies and approaches such as DSR, storage and new connections to other countries offer significant opportunities to improve security of supply and reduce the overall generating capacity that is needed. Market arrangements need to ensure that they can play their part in enabling secure supplies alongside flexible generation, and be compatible with a future electricity system in which consumers are engaged in their electricity consumption and demand is responsive, making efficient use of available generation and network assets.

Role of demand side response

C2.13 DSR is an active, short-term reduction in consumption whereby an energy user or aggregator guarantees to reduce demand at a particular time. It enables this by shifting demand from periods where demand is greater than supply to periods where supply is more plentiful – for example, by self-supplying using local back-up generation, or by not using the electricity at that time. The introduction of Smart Meters could increase the opportunities for demand side participation, for example through greater use of time or price-sensitive tariffs[8].

C2.14 We envisage that DSR which can guarantee reduced energy use according to the specifications required could bid to act as part or all of the Strategic Reserve.

Role of storage and other non-generation technologies and approaches

C2.15 We envisage that other technologies and approaches, such as electricity storage, would be able to participate in the Strategic Reserve in the same way as generation capacity, provided they meet the required criteria.

Question 5: How can a Strategic Reserve be designed to encourage the cost-effective participation of DSR, storage and other forms of non-generation technologies and approaches?

Role of interconnection

C2.16 In principle, we would want to allow providers outside GB to participate in a Strategic Reserve through interconnection. However, in order to participate, providers outside GB would need to meet the same criteria as other reliable capacity. We accept that there may be a number of

8 For more information on demand side response see Chapter 3.

technical constraints to including providers outside GB in a Strategic Reserve. For example, providers outside GB may not be able to provide additional capacity if flows to GB are limited by interconnection capacity during scarcity situations.

Setting the reserve despatch price

C2.17 A key part of the design of a Strategic Reserve is deciding the rules governing when it would be used or 'despatched'. In the Electricity Market Reform Consultation Document we considered two potential options for despatching the Strategic Reserve:

- **last-resort despatch:** the Strategic Reserve is only used after all other resource has been exhausted and is despatched at VoLL; or
- **economic despatch:** the Strategic Reserve is despatched when the market price reaches a certain level and sold into the market at this price[9].

C2.18 We have considered both options and prefer a form of economic despatch intended to address concerns expressed by stakeholders. In particular, we propose setting the despatch price high enough to avoid significant distortions to the market. However, we note the arguments are finely balanced and seek views on the most appropriate despatch model.

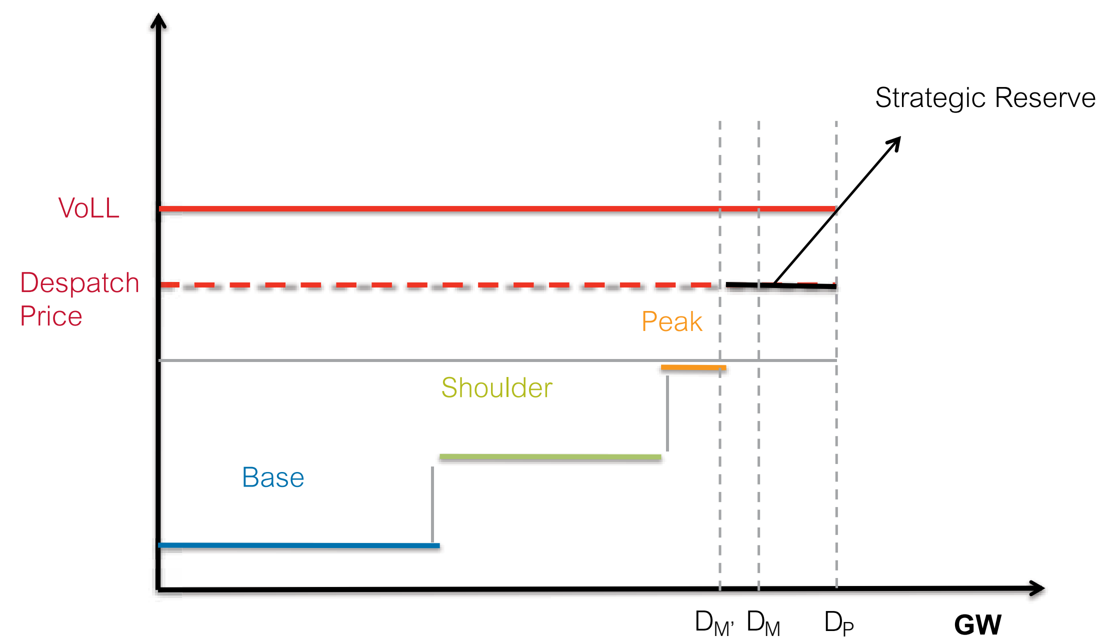
Economic despatch

C2.19 For our preferred economic despatch model, Strategic Reserve would be despatched at a fixed despatch price. This would be transparent, and set high enough above the highest long-run marginal cost in the electricity market to minimise distortion, but below VoLL. When the price rises above this fixed price, the necessary quantity of Strategic Reserve is despatched.

C2.20 The operation of Strategic Reserve with economic despatch is shown in Figure C4.

9 In the Electricity Market Reform Consultation Document, we defined economic despatch as despatch 'when it is cost-effective to do so…'. The phrase 'cost-effective' was ambiguous and so we have revised the definition here. We would not intend that the reserve be despatched at its short-run marginal cost as this would severely distort the energy market.

Figure C4: Operation of Strategic Reserve with economic despatch



Notes:

D_P is the maximum demand which can be served by a market which has a Strategic Reserve, and the capacity of the Strategic Reserve itself, combined.

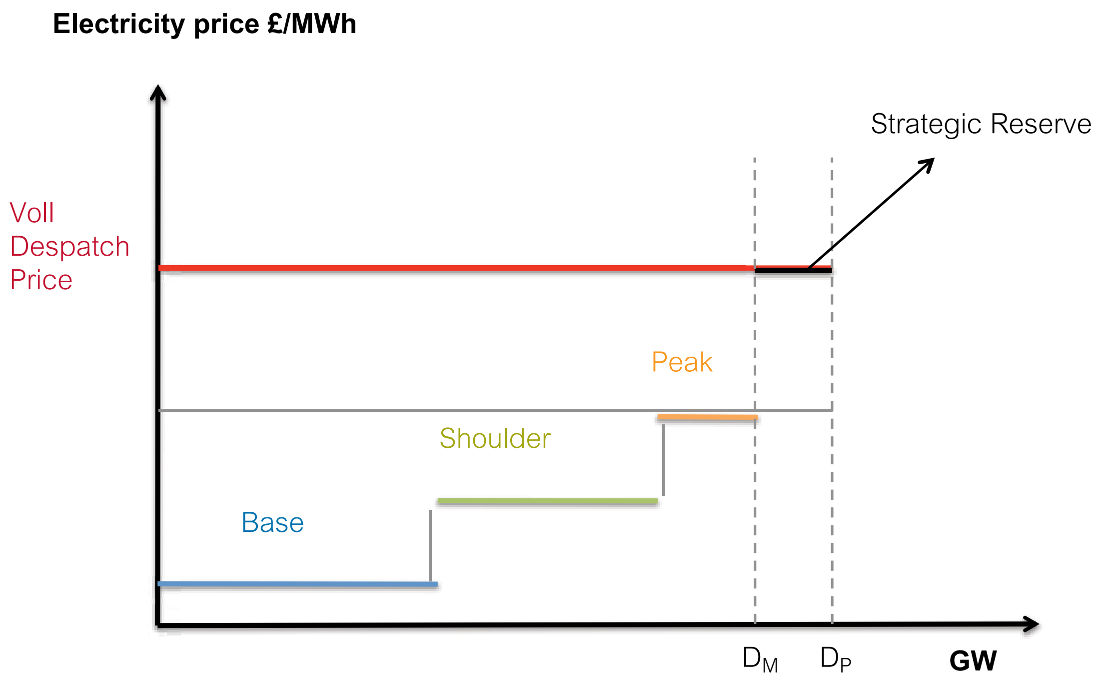
D_M is the maximum demand that could be served by a market with no Capacity Mechanism. Once a Strategic Reserve with a despatch price lower than VoLL is introduced, it will replace some electricity market generation, since it effectively caps the revenues that can be earned from times of peak demand.

$D_{M'}$ is the demand at which prices rise to the despatch price. When D_M' is reached the Strategic Reserve is despatched.

Last-resort despatch

C2.21 The operation of last-resort despatch is shown in Figure C5. Under a last-resort despatch model, the Strategic Reserve would be despatched once all other capacity has been despatched. It would be priced at VoLL. It should be noted that calculating this value is difficult, and the result not necessarily representative, as consumers are likely to attribute different values to electricity depending on their particular circumstances at any one moment. For example, a consumer with electric heating is likely to be prepared to pay more for this heating on a cold winter night than a mild spring day.

Figure C5: Operation of a Strategic Reserve with last-resort despatch



Comparison of economic despatch and last-resort despatch

C2.22 Respondents to the December 2010 Electricity Market Reform consultation were concerned that a Strategic Reserve would distort the electricity market, depress wholesale prices and reduce the incentives for investment. It could do this if the Strategic Reserve displaces plants that would otherwise have run. In considering the merits of last-resort despatch and economic despatch we have looked to address these concerns, considering the extent to which each model might:

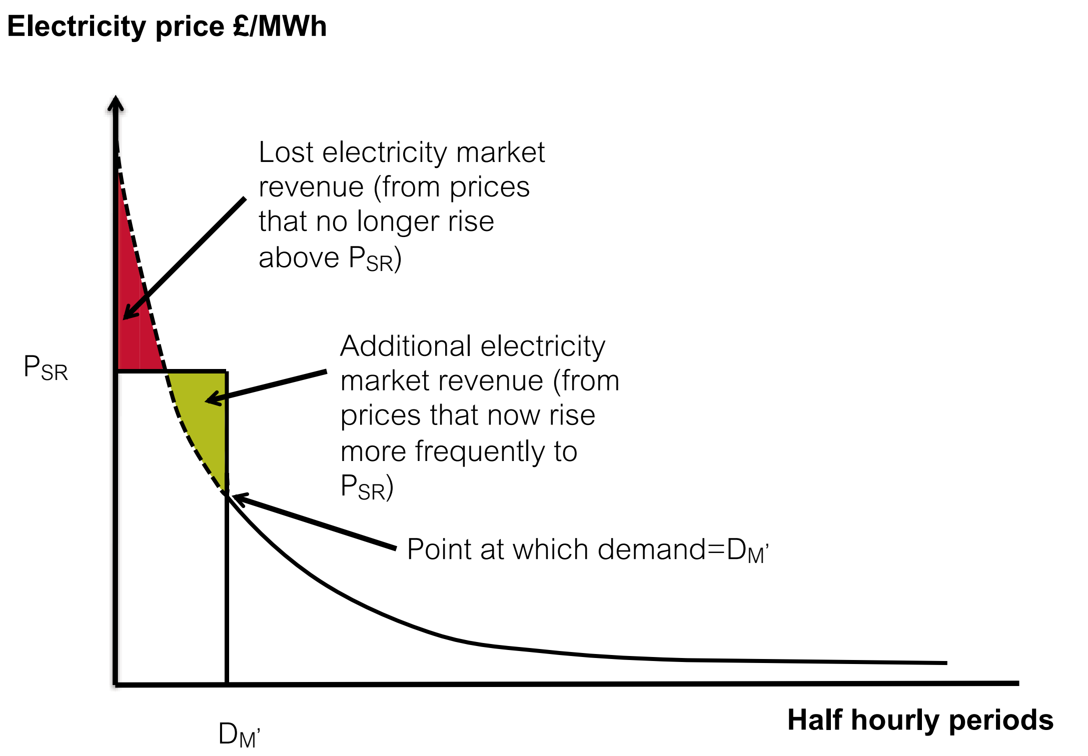
- distort the electricity market;
- affect the potential for generators to exercise market power;
- increase certainty for investors; and
- provide the best value for consumers.

C2.23 **Market distortion:** economic despatch could distort the market more than last-resort despatch if the fixed despatch price results in the displacement of significant volumes of electricity market capacity. However, it should be possible to set the total volume of Strategic Reserve and the despatch price so as to minimise this distortion.

C2.24 By setting a cap under economic despatch, generators lose some revenue (sometimes called ‘scarcity rents’) which they would ordinarily receive at times of scarcity, when prices could potentially rise as high as VoLL[10]. However, to the extent that the Strategic Reserve replaces some generation, the price will rise to the despatch price more frequently than it would otherwise have done.

C2.25 In principle, there is a despatch price (and related volume of Strategic Reserve) at which the impact on the investment incentives in the remainder of the market is neutral. At this price, the revenues lost to the remaining electricity market generators because the price no longer rises above the price cap are replaced. Replacement revenues would be earned during times when the price previously would have been lower than the cap but now rise to the cap price. The precise volume of Strategic Reserve that is required given the despatch price may be difficult to determine. In particular, this determination depends on a detailed knowledge of the load-duration curve which may not be readily available.

Figure C6: Illustrative price duration curve, showing how the introduction of Strategic Reserve could impact on electricity market revenues



Notes:
$D_{M'}$ is the demand at which prices rise to the despatch price. When $D_{M'}$ is reached the Strategic Reserve is despatched. P_{SR} is the price at which the Strategic Reserve is despatched.

C2.26 **Market power:** under economic despatch there is a reduced incentive for generators to withhold capacity and drive prices up, as prices cannot rise beyond the despatch price. A last-resort despatch model does little

10 Electricity generators earn scarcity rents when there is not enough electricity supply to meet demand. At that these times the electricity price is not being set by the short-run marginal cost of the most expensive generator running, as it is ordinarily. Instead, the electricity price is being set by the price which the most expensive peaking plant is able to charge.

to address the potential incentive on generators to exercise market power by withholding generation at times of scarcity because there is still a lot to gain from shortage – namely bidding prices up to VoLL.

C2.27 **Investor certainty:** in comparison with economic despatch, last-resort despatch at VoLL could lead to increased investor uncertainty. First, because reliance on such volatile prices means that investment may be perceived as risky. Second, because investors could be concerned that a last-resort despatch model with a high associated price for electricity generated (i.e. VoLL), the effective price cap, would be more likely to lead to pressure for regulatory intervention. This could, for example, be the case where following a number of uses of Strategic Reserve, wholesale prices had risen to VoLL. Investors may have greater certainty on their investment decisions if there were an economic despatch model with a lower price cap.

C2.28 Furthermore, when compared to last-resort despatch at VoLL, economic despatch could result in potentially more predictable, more frequent, but flatter peak prices.

C2.29 **Value to consumers:** last-resort despatch Strategic Reserve should limit the distortion to the electricity market. However, the value to consumers of despatch if the electricity from this Strategic Reserve were sold at VoLL would be questionable because this means pricing the Strategic Reserve at a level where consumers are by definition indifferent between paying for extra capacity and accepting blackouts.

C2.30 Economic despatch, with a despatch price below VoLL, should provide greater economic value to consumers who would pay less for the lights to stay on than the cost of a blackout at times of extreme scarcity. However, at times of moderate scarcity, prices may rise higher than they would have done otherwise.

C2.31 **Conclusion:** we are keen to ensure that the design of a Strategic Reserve does not undermine investors' incentives to invest in reliable capacity, while ensuring that security of supply is maintained at least cost to consumers. Hence both despatch models have been considered to mitigate this concern. On balance we believe that economic despatch is the better solution as, when compared to last-resort despatch, it:

- is more likely to reduce the incentive to withhold generation during periods of scarcity;
- provides a more stable investment environment; and
- would allow Strategic Reserve to provide greater economic benefit to consumers than last-resort despatch.

Question 6: Government prefers the form of economic despatch described here. Which of the proposed despatch models do you prefer and why?

Where is the despatch price set out and how could it be changed?

C2.32 A number of respondents to the December 2010 consultation argued that during periods of high prices, there could be increased pressure to lower the despatch price as a lever to reduce wholesale prices. This concern could damage investor confidence as reducing the despatch price would also lower the cap to which wholesale prices could rise, increasing the 'missing money' problem[11]. It is important that the despatch price is as independent of such pressure as possible in order to provide investors with a stable environment. Respondents were also keen that the Strategic Reserve methodology should be clear and transparent.

C2.33 The proposed model of economic despatch is intended to mitigate this concern. In addition, we propose that the Strategic Reserve methodology and despatch price would be governed by a defined change process. This change process would require sufficient time for assessment, consultation and review of any proposed changes before they are made. We welcome views on how this would best be accomplished.

Question 7: How would the Strategic Reserve methodology and despatch price best be kept independent from short-term pressures?

Should Strategic Reserve be periodically reviewed?

C2.34 A number of respondents to the December 2010 consultation were concerned that a tender for targeted resource could distort the market. As noted above, we are keen to ensure Strategic Reserve minimises this potential distortion and have developed the proposed design to assist this. In addition, a periodic review process could be introduced to consider the impact of Strategic Reserve on the market and assess whether the despatch price is correctly set.

Question 8: Do you agree that a Strategic Reserve should be periodically reviewed? If so, who would be best placed to carry out the review and how often should it be reviewed?

11 The expectation of price caps in energy markets leads to 'missing money'. At times of system tightness, generators should be able to raise their prices to the point where they can cover their long-run marginal costs, and ultimately to Value of Lost Load. However, generators may not be able to realise the necessary prices and hence cover their long-run costs. Reasons for this include actions taken by the System Operator (SO) to balance the system that are not priced correctly, as well as regulatory intervention. In particular, investors are likely to worry that periods of high prices will lead to regulatory intervention in the form of price caps, and this worry (even if it never materialises) will reduce incentives to invest.

Into which market should Strategic Reserve be sold?

C2.35 In designing the operation of the Strategic Reserve, a decision would need to be taken on the market into which the Strategic Reserve should be sold. We consider there are at least two options: the Balancing Mechanism or a day-ahead market.

C2.36 If Strategic Reserve were sold into the Balancing Mechanism then it would be included as an offer at the despatch price. This offer would be considered by the SO as with any other offer. The offer price of Strategic Reserve would then be included in the cash out calculation.

C2.37 An alternative is also to offer the Strategic Reserve in a forward market, e.g. a day-ahead market. This could be accomplished by offering the Strategic Reserve to the market at the despatch price.

C2.38 Strategic Reserve could be sold into the Balancing Mechanism, since this appears to be the most straightforward option, although we recognise that selling forward would provide useful signals of the need for the reserve.

Question 9: Into which market should Strategic Reserve be sold and why?

Interaction with short-term balancing

C2.39 There may be some interactions between a Strategic Reserve and short-term balancing arrangements such as STOR[12]. For example, where a STOR contract is for capacity capable of running for a longer, sustained period, this capacity could be considered to help with the problem of resource adequacy rather than short-term operational security[13]. There is likely to be potential for intelligent links between the mechanisms. Resource adequacy is the problem we intend to address with a Capacity Mechanism, and operational security is the problem STOR will need to continue to address in future. We would carefully consider these interactions if implementing a Strategic Reserve.

Interaction with Feed-in Tariff with Contract for Difference

C2.40 A major component of the Electricity Market Reform package is support for low-carbon generation through Feed-in Tariff with Contract for Difference (FiT CfD). There may be interactions with the proposed Capacity Mechanism given that both policy instruments affect the amount of capacity that will be brought forward.

C2.41 The Strategic Reserve would operate ‘outside’ the electricity market. We assume that most participants in the Strategic Reserve would not be plants eligible for a FiT CfD, so our initial view is that there would be limited interactions between Strategic Reserve and FiT CfD. The exception could be where biomass generation or fossil fuel generation

12 See the Short-Term Operating Reserve box in Chapter 3.

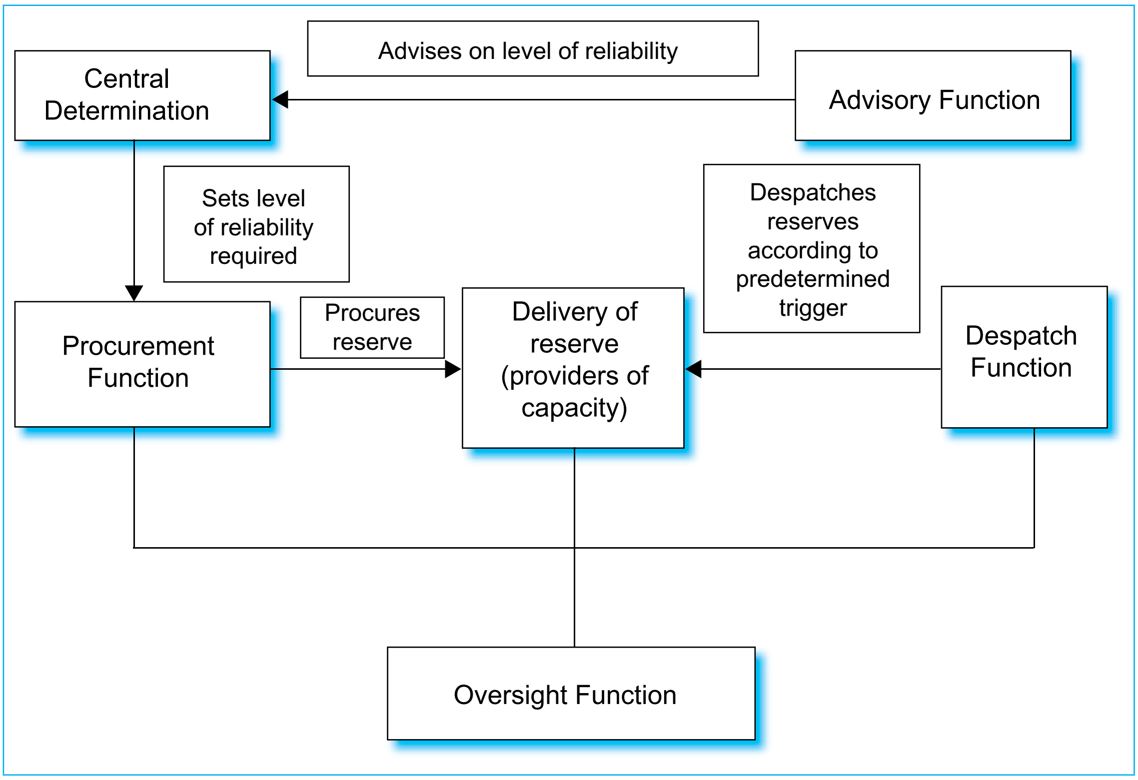
13 This terminology and some different security of supply challenges are discussed in Chapter 3.

with Carbon Capture and Storage (CCS) wanted to participate in the Strategic Reserve. We will continue exploring potential interactions as the proposals are developed.

Functional groupings

C2.42 Figure C7 shows six key sets of functions involved in the delivery of a Strategic Reserve.

Figure C7: Key sets of functions involved in the delivery of a Strategic Reserve



Strategic Reserve advisory function

C2.43 The advisory function would provide advice enabling a central determination on the required level of reliability to be made. The annual report by GEMA on security of electricity supply provided for in the Energy Bill 2011 would form a key element of this advice.

Strategic Reserve procurement function

C2.44 The procurement function would procure the required volume and mix of Strategic Reserve.

Strategic Reserve despatch function

C2.45 The despatch function would despatch the Strategic Reserve when required according to the methodology. It would also monitor the activity of the delivery function to check providers of reliable capacity are available when required and deliver the required volumes.

Strategic Reserve delivery function

C2.46 The delivery function comprises all providers of reliable capacity (generators, DSR, storage and interconnection) procured by the procurement function to deliver the Strategic Reserve. The despatch of the Strategic Reserve delivery function would be controlled by the despatch function.

Strategic Reserve payment function

C2.47 The payment function would calculate the payments due to organisations in the delivery function and manage the financial settlement of those payments.

Strategic Reserve oversight function

C2.48 The oversight function would monitor the activity of the procurement function and despatch function.

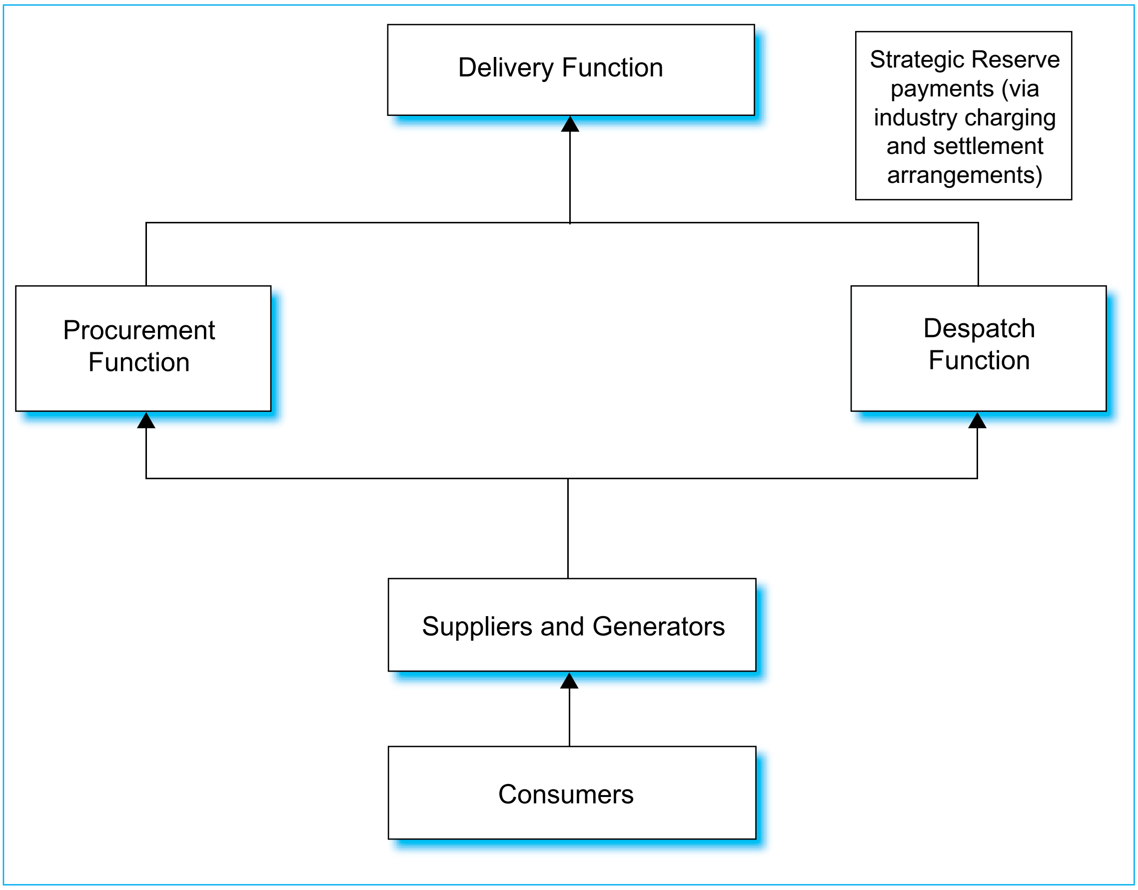
C2.49 Chapter 4 of this White Paper sets out the Government's position on institutional arrangements. The Government will announce details of organisational arrangements for Electricity Market Reform around the turn of the year.

Question 10: Do you have any comments on the functional arrangements proposed for managing a Strategic Reserve?

Financial Flows

C2.50 Figure C8 sets out the main financial flows associated with the operation of the Strategic Reserve Capacity Mechanism.

Figure C8: Financial flows of the Strategic Reserve



C2.51 The principal and administrative costs of the mechanism would be met by market participants, based on market share through industry charging and settlement arrangements. The costs of the Strategic Reserve would eventually be passed to end consumers by adjusting the prices in retail markets. In return for this, consumers would benefit from the higher capacity margins provided by a Strategic Reserve, which would help reduce the risk of blackouts.

Question 11: Given the design proposed here and your answers to the above questions, do you think a Strategic Reserve is a workable model of Capacity Mechanism for the GB market?

C.3 Market-wide mechanism: Capacity Market

Overview

C3.1 In light of responses to the December 2010 consultation concerns on the potential impacts of a targeted mechanism, Government has considered the merits of a market-wide mechanism in the form of a Capacity Market in more detail.

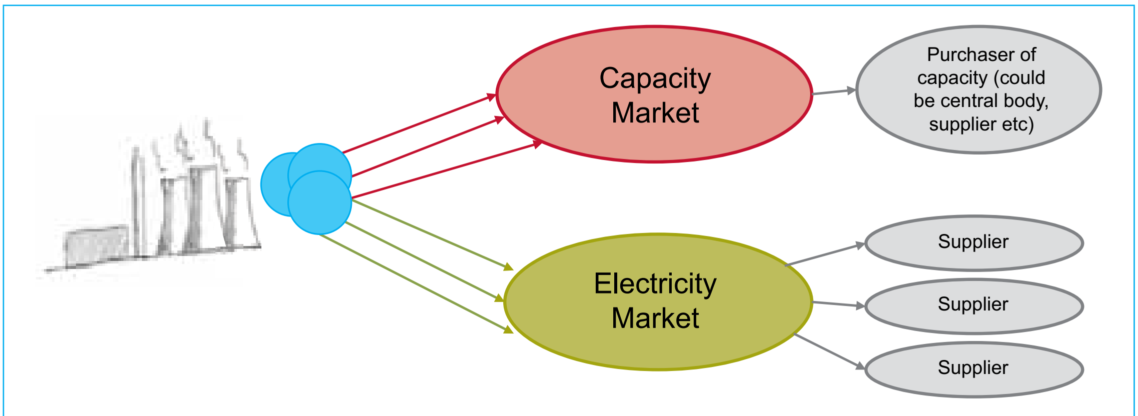
C3.2 Such a mechanism would introduce a market for capacity in addition to the existing electricity market and providers of capacity could operate in both markets.

C3.3 This section outlines some of the general design features of a Capacity Market, and describes in more detail a particular form of a Capacity Market, which we refer to as a Reliability Market.

C3.4 Figure C9 shows how a Capacity Market works. The required volume of reliable capacity would be determined centrally based on forecasts of the peak demand some years ahead. That total amount of demand for capacity would be purchased from any provider willing to supply it, subject to its ability to meet the necessary criteria. Providers of capacity could include existing generators, companies that are planning to build a new power plant, and companies offering other forms of capacity such as DSR or storage.

C3.5 In effect, providers of capacity in a Capacity Market substitute uncertain returns in the electricity market for long-term certainty from the Capacity Market. Consumers benefit from certainty of supply and increased price stability.

Figure C9: Operation of a Capacity Market



Note:

Providers of reliable capacity participate in the Capacity Market and/or the electricity market. In the Capacity Market, they are incentivised to be available (or penalised for not being available).

C3.6 The term 'Capacity Market' is broad. Any Capacity Market must address at least two questions: how to decide how much capacity can be offered to the market by a given power plant (that is, the nature of the product they can offer); and what penalties to impose if the promised capacity is not available when required during the contract period.

C3.7 These questions could be addressed by defining an administrative process to determine the appropriate amount of capacity for each power plant, set the conditions under which the plant must be available, and impose penalties when the plant is not available.

C3.8 An alternative approach is to use market-based incentives for availability, known as a Reliability Market. Under this approach, a financial incentive – such as a financial call option – is put in place to incentivise availability, and provide penalties for unavailability.

C3.9 This section first considers design features that are common to all Capacity Markets, then considers those relating to a Reliability Market in more detail, before concluding with a discussion of other issues relevant to all types of Capacity Market. We have included detailed questions on a Reliability Market given its innovative nature in the GB market, but other forms of Capacity Market remain under equal consideration.

Setting the required level of capacity

C3.10 For a Capacity Market, a decision will be needed on the desired level of capacity in the GB market[14]. In contrast to a Strategic Reserve, however, it is not necessary to predict the level of capacity the market will bring forward.

C3.11 We propose that the decision about the required level of capacity would be taken centrally each year based on annual advice on:

- the level of electricity demand over the next four years (considering peak demand and demand variability); and
- the likely cost of providing different levels of reliability.

C3.12 To assist this central decision, GEMA would provide an annual report on security of electricity supply. Primary legislation to enable this is being sought through the Energy Bill 2010–11. Further independent advice could be commissioned if necessary.

C3.13 It should be noted that, if low-carbon generators receiving a FiT CfD are excluded from the Capacity Market, it would be necessary to estimate the reliable capacity offered by such generators and contract for what is left after subtracting that capacity from the target capacity level[15].

C3.14 For a Capacity Market it is possible that in future consumers could be more engaged in the decision about the minimum level of supply they require based on the cost to them of differing levels of capacity.

14 This is because reliability is a public good. When prices are falling, companies that did not sign contracts for capacity can offer energy more cheaply than suppliers that bought contracts for capacity. Consumers will switch and may cause the company that bought contracts for capacity to become insolvent. So because of retail competition, suppliers are not credible counterparties for contracts for capacity. The capacity which they would purchase is therefore less than the required amount.

15 See 'Interaction with Feed-in Tariff with Contract for Difference' for more detail.

How and by whom capacity is bought

C3.15 Once the desired quantity of capacity has been determined there are several ways capacity could be purchased in the ‘primary capacity market’[16]. The key questions are whether capacity is purchased by a central institution, or by suppliers; and whether it is purchased through an auction, or through bilateral markets. We have considered three options for addressing these questions.

C3.16 **A central institution buys capacity in an auction:** the desired quantity of capacity could be bought in an auction by a central institution, which passes on the cost and the paybacks (if any) to consumers during the delivery period. With this approach it is straightforward to ensure that the desired quantity of capacity is bought. Financial counterparty risk (the risk that the seller of capacity would be unable to provide the capacity or to pay the required unavailability penalty) would be held by the central agency. If a central institution buys capacity the allocation of cost to suppliers could wait until the customer base for the delivery period is known, which could limit the secondary market transaction costs that suppliers would face for re-trading to reflect changes due to customer switching.

C3.17 **An obligation is placed on suppliers to buy capacity in an auction:** the desired quantity of capacity could be bought in a central auction by individual suppliers. Under this approach it is straightforward to ensure that the desired quantity of capacity has been bought. Suppliers would need to re-adjust their positions in secondary markets to correct for changes in their capacity obligations due to customer switching up until the delivery period. This would incur further transaction costs. In the Reliability Pricing Model (RPM) Capacity Market of the North American PJM system,[17] suppliers can, in addition to participating in the auction, also ‘self-supply’ capacity and purchase capacity bilaterally.

C3.18 **An obligation is placed on suppliers to buy capacity in bilateral markets:** the desired quantity of capacity could be bought by suppliers in the form of bilateral contracts. With this approach it would be necessary to monitor whether suppliers purchased the right amount of capacity. As above, individual suppliers would need to re-adjust their positions in secondary markets to match changes in their customer base up until the delivery period, which would incur further transaction costs.

Question 12: How and by whom should capacity in a GB Capacity Market be bought and why?

16 See ‘Primary and secondary markets’ for discussion of the different markets for reliability contracts.

17 PJM is the electricity transmission system serving all or parts of Delaware, Illinois, Indiana, Kentucky, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, Tennessee, Virginia, West Virginia and the District of Columbia.

Contract duration

C3.19 The maximum duration of a contract for capacity determines how long the payment can be locked in by generators or non-generation providers of capacity such as DSR or storage. A longer contract duration has two main implications:

- **it reduces uncertainty** for market participants because they can lock in the payment for a longer time and are not exposed to the impacts of more frequent changes in the prices set in the Capacity Market; and
- **it leads to market foreclosure** because market participants can lock in payments for a longer time in the future (by choosing a longer contract duration). For the contract duration, the payment will not be influenced by future developments such as lower demand, which would have led to lower prices.

C3.20 In the capacity markets in New England and Colombia, the contract duration for existing plants is one year, while plants that have not yet been built can optionally increase the contract duration (and thus lock in the payment) for longer periods of up to twenty years[18]. For plants that require additional investments, an intermediate solution is used.

Question 13: What contract durations would you recommend for a Capacity Market?

How far ahead should contracts be purchased?

C3.21 The principal goal of a Capacity Mechanism is to ensure that sufficient capacity is available to achieve a required level of reliability, including the ability to meet peak demand.

C3.22 For both a Strategic Reserve and a Capacity Market, consideration needs to be given to the lead time between procurement and capacity being required to be in place. In particular, there are considerations associated with longer or shorter lead times in relation to the construction of new plants.

C3.23 The longer the lead time, the more project risks are reduced (including construction risks for new plants being built) and investment incentivised. Longer lead times will therefore provide a greater potential role for new entrants. This should reduce the overall costs of providing capacity. On the other hand, the further in advance capacity is sold, the greater the potential margin for error in projections of future peak demand. This could lead to over or under-procurement and investment.

C3.24 In principle there are the following options for lead times for purchasing contracts:

18 These markets are referred to in Section 4 ‘International Comparisons’.

a. **shorter than shortest construction time:** demand projections are likely to be more accurate for these nearer-term timescales, but the payment for capacity could not serve as a security to finance construction of new plants, which could lead to higher prices in the Capacity Market. This may tend to incentivise DSR ahead of new construction;

b. **between the shortest and longest construction time:** demand projections would be less uncertain than for the longer term. The promised payment could be used as a security to finance the construction of plants with shorter construction times, which could lower the prices in the Capacity Market; and

c. **longer than longest construction time:** demand projections would be very uncertain. Consequently it is not clear there would be additional benefit in terms of investor certainty from taking a longer term approach; and/or

d. **special arrangements for plants with long construction times:** plant requiring longer construction times could be allowed to agree later starting dates.

Question 14: How long should the lead time for capacity procurement be? Should there be special arrangements for plants with long construction times?

Primary and secondary markets

C3.25 The primary capacity market is where capacity is first allocated. Options for this are discussed in 'How and by whom capacity is bought' above.

C3.26 Secondary capacity markets, where capacity could be re-traded once allocated through the primary capacity market, are used in some existing systems, for example, in the forward capacity market of PJM and the reliability market of Colombia. They are needed for two reasons:

- providers of capacity may need to reallocate their obligations, for example, because of planned maintenance or unexpected breakdowns;
- it will make the market more accessible to DSR providers. The operating characteristics of DSR are typically such that it can run only for short periods of time (which may be one reason why only a limited number of DSR providers have STOR contracts). The secondary market should provide a much greater opportunity for participation of DSR.

C3.27 If the physical back-up requirements in the primary capacity market are sufficient to ensure the required amount of capacity is constructed, there might be a case for opening up the secondary market to financial players to increase liquidity. However, this requires careful assessment to avoid undermining the efficiency of the Capacity Mechanism to incentivise investments.

C3.28 The products which will be traded in the secondary market are the same products that are sold in the primary market. However, the contract lead time in secondary markets could be much shorter, e.g. down to a single day, and the contract duration much lower, e.g. down to a single balancing period.

Question 15: Should there be a secondary market for capacity? Should there be any restrictions on participants or products traded?

Determination of capacity credit and penalties for non-availability

C3.29 As discussed above, all market-wide capacity mechanisms must define the nature of the product that is being traded, and the penalties for non-availability.

C3.30 **The nature of the product being traded:** Not all capacity is equivalent. It would be inappropriate, for example, to treat a 1 GW Combined Cycle Gas Turbine (CCGT) power station as equivalent to a 1 GW wind farm – the CCGT can be relied upon to provide reliable capacity when needed in a way that the wind farm cannot. This is why the capacity of a generator is sometimes quoted as 'de-rated capacity', a figure that attempts to capture the capacity that can be relied upon at times of peak demand[19].

C3.31 **Penalties for non availability:** In a Capacity Market, providers of capacity receive a payment for providing capacity. In return, there need to be penalties for providers who are not available when required.

C3.32 In several existing Capacity Markets a central approach is taken to address these issues. For example, in the RPM of the PJM system, the capacity that a provider is able to offer into the market is calculated centrally based on a number of technical parameters such as outage rates. These are estimated based, for example, on historic data or through comparison with similar types of generation. A series of 'resource performance assessments' are carried out to assess whether the resource honoured its commitments during the contract period. If the resource is assessed as having failed to deliver the required level of capacity, then an administratively determined penalty is imposed and the revenue from the charges given to resources that exceeded their commitment levels[20].

C3.33 This approach is relatively straightforward but does face a number of complexities, for example the challenge of setting an appropriate penalty level, specifying when availability is required, and resolving potential disagreements over whether the provider was 'at fault' when unavailable.

19 The de-rated capacity margin is the capacity margin adjusted to take account of the availability of power plants, specific to each type of generation technology. It reflects the expected proportion of a source of electricity which is likely to be technically available to generate (even though a company may choose not to utilise this capacity for commercial reasons).

20 For further detail on the 'Reliability Pricing Model' see, for example, PJM Manual 18, PJM Capacity Market, Revision 12, 2011, http://www.pjm.com/markets-and-operations/~/media/documents/manuals/m18.ashx.

C3.34 An alternative approach to this challenge, using incentives in the form of financial call options, is discussed in the section below.

Question 16: What are the advantages and disadvantages of making a central, administrative determination of (i) the capacity that can be offered into the market by each generator; (ii) the criteria for being available; and (iii) the penalties for non-availability? In outline, how would you suggest making these determinations?

Reliability Market

Overview

C3.35 In some existing Capacity Markets, a central, regulatory decision is made concerning the capacity that can be relied upon for each type of generation and non-generation technology, and there are penalties for not being available during the contract period (as discussed above).

C3.36 A possible alternative approach, a **Reliability Market**, relies on financial incentives rather than centralised monitoring and administration.

C3.37 In a Reliability Market, what is purchased from providers (which could be generators or non-generation approaches such as storage or DSR) is a 'reliability contract', essentially a call option[21]. The reliability contract provides a hedge for the holder, enabling the holder to purchase energy at no more than the 'strike price' or, if energy is simply not available, to be compensated for the missing energy[22]. In return for this hedge, the provider receives a payment (the option premium) which provides a more reliable source of income on which to base an investment decision.

C3.38 In a Reliability Market:

- the provider is able to make a decision about how much capacity they can reliably supply (there may still need to be some checks);

21 A call option is a contract that gives the buyer of the option the right (but not the obligation) to purchase an agreed quantity of a commodity from the seller at an agreed time for an agreed price. The buyer of the option therefore knows the maximum price they will have to pay for the commodity (up to the agreed quantity). If there is a liquid market in the underlying commodity with a well-defined price, then the option may be settled financially, rather than through physical delivery: the buyer purchases the commodity themselves in the market and is paid the difference between the agreed price and the market price. In either case, the buyer of the option receives the commodity and pays, at most, the agreed price. It is slightly easier to discuss the financial case, which is what we do here.

22 '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. Hedges can be either financial or physical. For example, a generator might hedge the risk of electricity price movements:

- financially by selling electricity in the forward markets or entering into long-term contracts; or
- physically by integrating with an electricity supply business, such that any downward movement in prices resulting in a loss in revenues for the generation business is offset by an increase in revenues for the supply business.

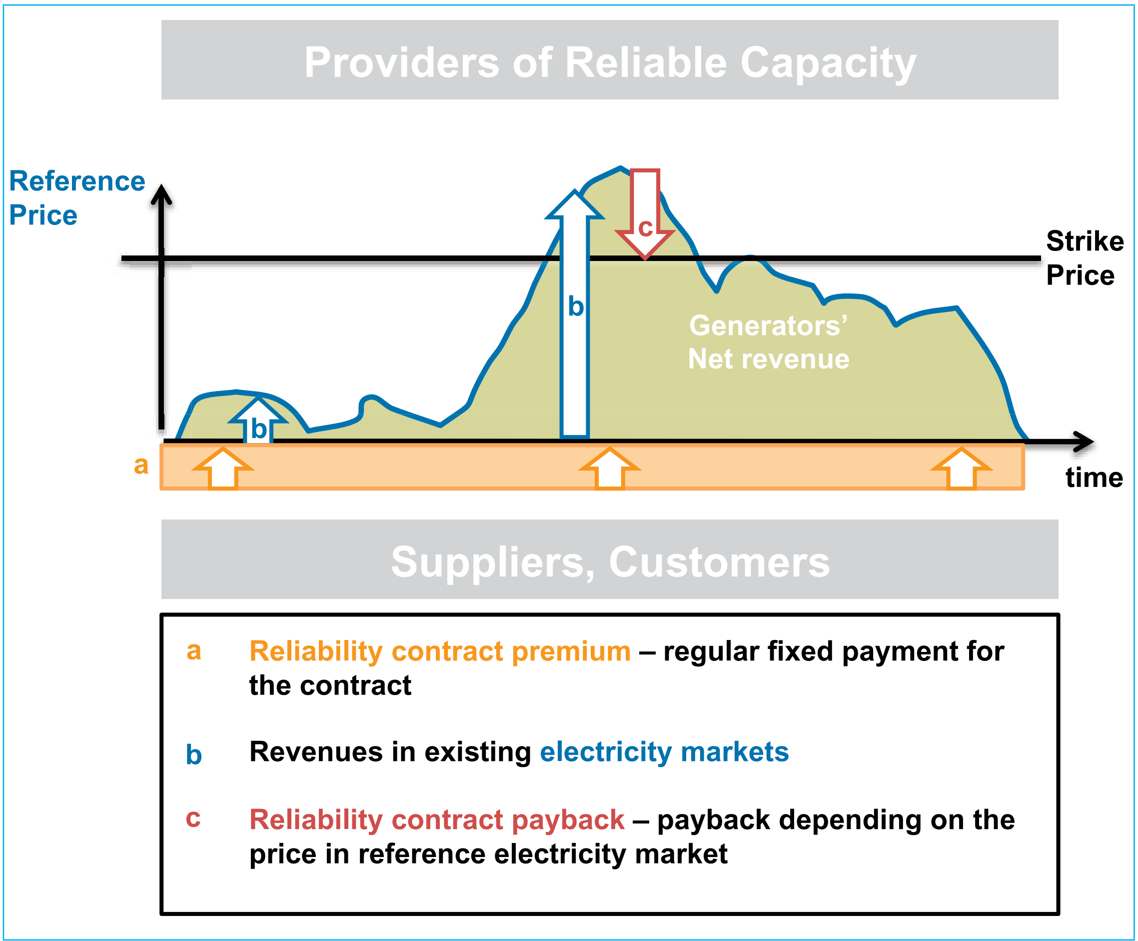
The 'strike price' is a price agreed by the parties to the reliability contract and represents the effective maximum price that the electricity buyer will have to pay for the volume agreed in the contract. When the market price is higher than the strike price, the seller of the reliability contract pays the buyer the difference in price for the total volume of electricity agreed.

- the times when availability is required are defined just as times when prices are high; and
- there are no regulatory decisions over whether the provider is at fault.

C3.39 As far as we are aware, reliability contracts have only been introduced in two electricity markets: Colombia and New England (and the New England variant caps the option payments). However, derivatives contracts are commonly used for hedging in many commodities markets (including electricity in e.g. Australia) so the principles underlying a Reliability Market are not new.

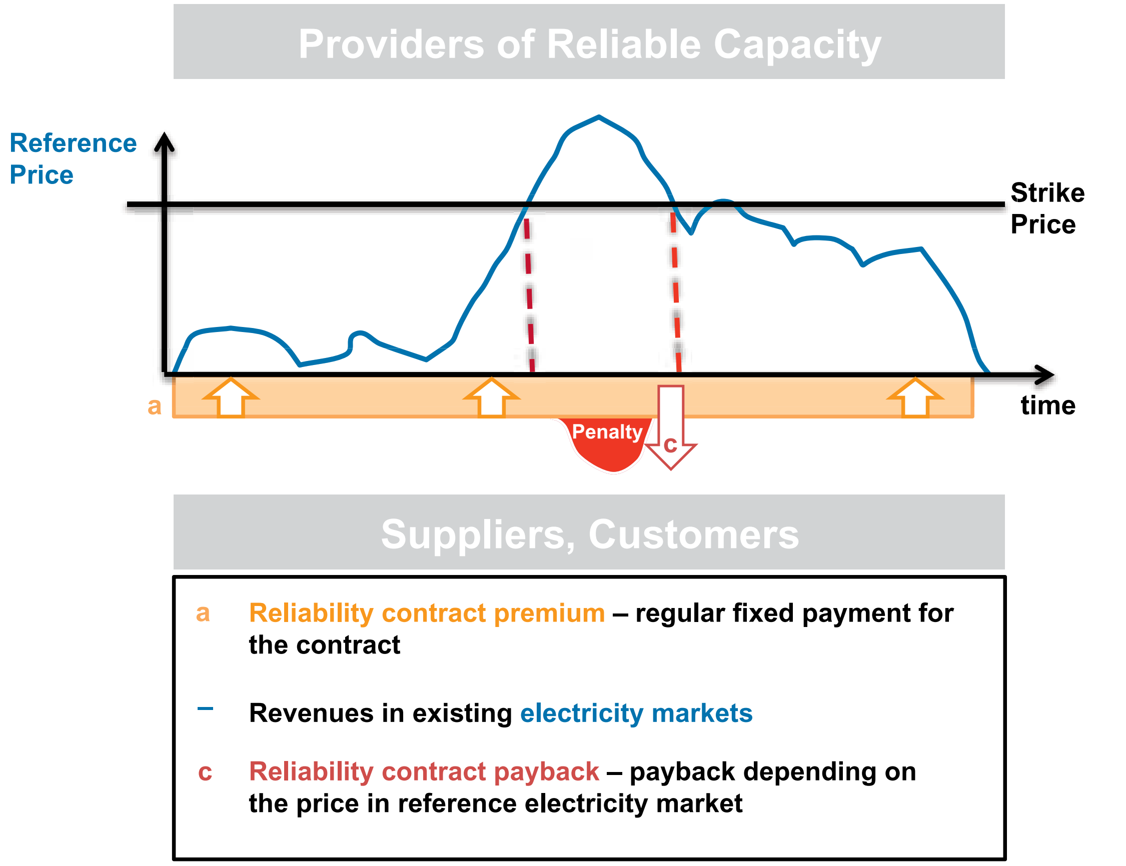
C3.40 **Overview of cash flows:** to illustrate the principles behind a reliability contract, Figures C10 and C11 give an overview of the cash-flows involved after the contract has been sold. If the provider of reliable capacity is available, the flows are as shown in Figure C10. An overview of the cash flows if the provider of reliable capacity is unavailable is shown in Figure C11.

Figure C10: Payments for reliability contracts if the provider is available



Note:
In addition to the revenues from the electricity market (arrows b), providers of reliable capacity that sold a reliability contract will receive a fixed premium from suppliers (arrows a), but pay suppliers back the difference between the reference price and the strike price when the reference price rises above the strike price (arrow c).

Figure C11: Payments for reliability contracts if the provider is unavailable



Note:

If generators are not available, they do not incur any revenues from electricity markets. However, if they sold a reliability contract they still receive the same premium from suppliers (arrows a), and pay to suppliers the difference between the price in the reference market and the strike price, when the reference price rises above the strike price (arrow c).

C3.41 This means:

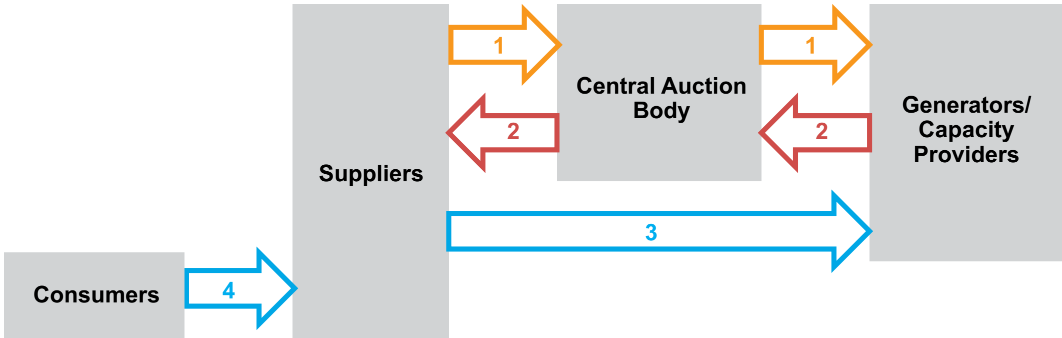
- consumers are hedged against the risk of high prices in return for paying a reliability contract premium;
- generators exchange part of their volatile revenues for more certain income;
- generators cannot increase their revenues by bidding strategically to increase prices above the strike price; and
- all providers of reliable capacity are incentivised by market prices to be available.

Financial flows

C3.42 Figure C12 sets out the financial flows associated with a Reliability Market. A Reliability Market would introduce two new payments. The first one is the reliability contract premium which is paid from electricity suppliers to providers of reliable capacity, and the second is the reliability contract payback of any revenues above the strike price from generators to suppliers. These payments could be merged into a single payment stream.

C3.43 If reliability contracts are bought in bilateral markets instead of a central auction, the reliability contract payments do not flow through the central auction body as in Figure C12, but directly from suppliers to contract providers[23].

Figure C12: Overview of Financial Flows for reliability contracts



1	Reliability contract premium – regular fixed payment for the contract
2	Reliability contract payback – payback depending on price in reference electricity market
3	Revenues in existing wholesale markets
4	Revenues in existing retail markets

Choosing the reference market

C3.44 Reliability Contracts oblige providers of reliable capacity to pay back the difference between the price in a reference market and the strike price specified in the contract if the reference price rises above the strike price. To protect against the risk of having to pay back more than they earn, generators have an incentive to sell their power in the reference market, or at least wait until the reference price is known, before deciding whether to sell in the reference market or speculate on higher prices in markets closer to real time.

C3.45 Once a reliability contract is signed, the paybacks which providers of reliable capacity have to make depend entirely on the price in the reference market. The choice of the reference market is therefore central to the design of a Reliability Market: it has important implications for liquidity in different markets and the extent to which reliability contracts could mitigate market power.

C3.46 **Impacts on liquidity:** The choice of reference market for a Reliability Market could have impacts on the liquidity of forward markets. If the price in the reference market rises above the strike price, providers of reliable capacity that sold a reliability contract will have to pay back the difference to the counterparty. Whenever there is a chance that prices in the reference market might rise high enough for this to happen, providers of reliable capacity may prefer to sell their electricity in the

23 See 'How and by whom contracts are bought'.

reference market to hedge against the risk of these paybacks. Until the price in the reference market has been determined, there is always a chance that it might rise above the strike price, due for example to a demand spike or an unforeseen outage of a plant.

C3.47 Providers of reliable capacity therefore have an incentive to not sell their electricity in markets before the reference market. Once the price in the reference market has been determined, the payback is a sunk cost, so will not affect the trading strategy (and resulting liquidity) in subsequent markets. This means that, if the market chosen is close to real time, the impact of liquidity in forward markets may be greater.

C3.48 **Impacts on market power in the electricity market:** A reliability contract effectively caps the net price that the buyer has to pay for electricity in the reference market at the contract's strike price. Hence, buyers of reliability contracts are never forced to pay more than the strike price as long as they purchase the electricity no later than the reference market. Presumably, this limits the opportunity for generators to increase prices through strategic bidding in those markets[24], though such opportunities may still exist in markets which occur after the reference market.

C3.49 The following options are available for specifying reference markets:

a. **Regulator specifies the reference market for all contracts:** the reference market could be specified by the regulator. In principle this could be any market – from bilateral forward markets to real-time prices in the balancing mechanism. Given the impacts on market power described above, it may be argued that the reference market should be as close to real time as possible, in particular since short-term adjustments will become more important when there is more intermittent wind generation in the market. However, there is a trade-off because of the potential for reducing liquidity in earlier markets. In addition the decision should take into account the transparency and robustness of prices in different markets, and the possibility for generators outside GB to access these markets; or

b. **Suppliers specify the reference market for individual contracts:** as an alternative to centrally specifying the reference market, suppliers could buy reliability contracts that require physical delivery (rather than financial settlement). Under this model, the supplier would decide the appropriate time to 'call' the contract, which would be settled through a normal bilateral contract for electricity delivery at the strike price. In effect, the holder of the contract would determine the appropriate reference market. This model has the advantage of working coherently with our system of bilateral contracting but would be an innovative solution that has not been tried in other markets.

24 This could include overstating the price for providing energy or withholding supply from the market to increase prices.

In particular, it may not be compatible with high levels of vertical integration[25].

Question 17: How should the reference market for reliability contracts be determined and what would be an appropriate reference market if it is set by the regulator? How could any adverse effects of choosing a particular option be mitigated?

Setting the strike price

C3.50 For a Reliability Market, a decision would be needed on the strike price for reliability contracts, which in turn would determine the required contract premium.

C3.51 We propose that the decision about the level of the strike price would be taken by an appropriate organisation either in preparation for each auction (if the contracts were purchased in a central auction) or on a regular timetable, such as annually (if the contracts were purchased bilaterally). The strike price represents a view of the boundary between normal system operation and scarcity conditions, and should therefore take account of factors such as the cost to consumers, and the ability of the demand side to respond to wholesale prices.

C3.52 There is also a choice to be made in the detailed design of a Reliability Market about whether the strike price is fixed for the duration of the contract or indexed to some other reference price.

C3.53 The strike price could be **fixed** for the whole delivery period. An advantage of fixing the strike price would be transparency. Market participants know what to expect. A fixed strike price exposes generation companies to the risk of changes in variable costs, especially fuel costs. However, they can hedge these risks in commodity markets.

C3.54 The strike price could be updated during the delivery period by **indexing** the strike price to fuel costs or other input factor costs affecting the marginal costs of a particular plant. For operators of this type of plant, this approach removes the risk caused by variations in these costs (at least in respect of reliability contract obligations).

C3.55 However, the updating of an indexed strike price involves administrative costs and introduces a bias towards the technology whose costs are used as the reference index.

25 See 'Impact of vertical integration on availability signals' for more detail.

Question 18: For a Reliability Market, how should the strike price be determined? If using an indexed strike price, which index should be used?

Extent of physical and financial back-up required from providers of reliability contracts

C3.56 The goal of a Reliability Market is to ensure that:

- enough generating plants are in operation, or enough DSR or storage is enabled; and
- generators are producing electricity and responsive customers are reducing consumption when needed.

C3.57 Some forms of Capacity Market involve central administration of the capacity that generators can offer[26]. For a Reliability Market, it is possible to allow providers of capacity to sell as much capacity as they wish, as they will be financially penalised when the promised capacity is unavailable. However, if reliability contracts are merely financial instruments, it might be more profitable for speculative investors to sell contracts without investing in the necessary capacity. To encourage investment in the necessary capacity, a number of design options are available:

a. **no physical backing:** no ownership of reliable capacity or credible investment plans have to be proven for participation in the Reliability Market. This approach would not guarantee that reliability contracts actually result in provision of reliable capacity. However, consumers would receive appropriate financial compensation for outages or high prices. Providers would therefore be incentivised to build capacity to the extent that they think this is cheaper than to provide a financial compensation. In the absence of physical back-up requirements, there would have to be financial liquidity requirements to ensure that auction participants are credible counterparties. With this approach it would not be possible to allow different contract durations for new and existing plants because the contract is not linked to actual physical generation or demand adjustments[27];

b. **name plate capacity:** to sell reliability contracts, companies have to prove that they will construct or own plants or DSR capacity with a name plate capacity larger than or equal to the amount of reliability contracts they sell. This would bring the capacity that is provided closer to the target capacity while keeping the cost of monitoring low. However, investors could still build cheaper, less reliable power plants and sell more reliability contracts than they back up with investment; or

26 See 'Determination of capacity credit and penalties for non-availability'.

27 See 'Contract duration'.

c. **regulatory de-rated capacity:** to sell reliability contracts, companies have to prove that they will construct or own plants with a de-rated capacity larger than or equal to the amount of reliability contracts they sell. This ensures that the capacity target is met. However, the determination of de-rating factors by the regulator would significantly increase the cost of monitoring.

C3.58 In addition, consideration needs to be given to the degree of evidence required for financial back-up – that is, to ensure that participants selling reliability contracts are credible counterparties.

Question 19: For a Reliability Market, what level of physical back-up (if any) should be required for reliability contracts and how should it be monitored?

Interaction with short-term balancing

C3.59 Reliability contracts are very similar to STOR contracts for flexible service used by National Grid. STOR contracts include information about the location of the plant and the minimum capacity it is able to provide which is useful for National Grid to determine the optimal despatch plan.

C3.60 If reliability contracts are referenced to the Balancing Market, they would probably remove the need for some of the STOR contracts[28].

C3.61 If reliability contracts are referenced to earlier markets, they cannot replace STOR contracts. However, careful consideration will be required of whether this would lead to double payments or gaming if a plant that signed a reliability contract is also allowed to sign a STOR contract.

Impact of vertical integration on availability signals

C3.62 Reliability contracts are signed between providers of capacity and a central buyer or suppliers (on behalf of consumers). In the GB market there are currently six large vertically-integrated companies[29]. If reliability contracts are procured through a supplier obligation it is therefore likely that a large proportion of the contracts will be between the supply and generation arms of the same company. This risks reducing the effectiveness of reliability contracts for ensuring capacity is available when needed, since contract paybacks would simply be a transfer of money within the same company. Contract paybacks would increase the profits of the supplier part of a vertically-integrated company by the same amount as they decrease the profitability of its generation business, so the profits of the company as a whole are not affected. As long as the contract paybacks don't leave the company, they might not influence decisions to construct new capacity and/or make capacity available when required by the contract.

28 See 'Choosing the reference market' for further detail.

29 Vertically integrated organisations control businesses on several levels along the supply chain. For example, in the GB electricity market, the large electricity generating businesses are often owned by the same organisations that own electricity supply businesses.

C3.63 We see two potential solutions to this problem. One is to monitor the physical backing of any market participant selling reliability contracts. The other is to ensure that the option payments eventually leave the company and flow to consumers (on whose behalf the contracts have been purchased). However, we are open to the possibility that there may be other solutions that are more straightforward or less costly.

C3.64 **Physical back-up requirements:** To participate in a Reliability Market providers of capacity could have to meet a variety of requirements in the form of proofs of reliable physical capacity[30]. More stringent entry requirements would improve the incentives to provide reliable capacity by increasing the cost of selling contracts without reliable physical back-up. This incentive is not affected by vertical integration.

C3.65 Of course, this would require a monitoring process, as well as a process for penalising companies who did not supply the level of reliability promised[31].

C3.66 **Ensure reliability contract paybacks to consumers:** It would be possible for reliability contracts to be, in effect, purchased by suppliers on behalf of consumers and therefore that any payments made to the supplier during times of high prices should be passed directly to those consumers. In this way the vertically-integrated company would face the appropriate availability incentives. However, as with other aspects of the reliability contract model in the GB system, this proposal is novel.

Question 20: Do you agree that a vertically-integrated market potentially raises issues for the effectiveness of a Reliability Market? If so, how should these issues be addressed?

Other considerations in designing a Capacity Market

C3.67 The section above deals with specific considerations in designing the Reliability Market form of a Capacity Market. The remainder of this section deals with other considerations to be taken into account in designing all forms of Capacity Market.

Interaction with Feed-in Tariff with Contract for Difference

C3.68 A major component of the Electricity Market Reform package is support for low-carbon generation through FiT CfD. There may be interactions with the proposed Capacity Mechanism given that both policy instruments affect the amount of capacity that will be brought forward.

C3.69 A Capacity Market could interact with low-carbon support since both provide support for capacity but the two offer different incentives for reliability.

C3.70 For example, consider the interaction between a Reliability Market and a FiT CfD for nuclear plant. We expect that nuclear, as a baseload

30 Discussed in 'Extent of physical and financial back-up required from providers of reliable capacity'.

31 See 'Determination of capacity credit and penalties for non-availability'.

plant, may receive a FiT CfD that uses the year-ahead forward price as the reference price. Under this FiT CfD the generator will be exposed to the short-term price and could in principle sell a reliability contract. However, part of the remuneration the generator receives from this reliability contract is required to provide compensation for lower wholesale prices and, since the FiT CfD already does this, there is a risk of overpayment.

C3.71 Conversely, for intermittent plants such as wind we expect generators to receive a FiT CfD referenced to the day-ahead price. Now, when the price is high both in the reference market for FiT CfD and in the reference market for reliability contracts, both contracts would require a payment from the generator. Therefore if a generator sells a reliability contract in addition to having signed a FiT CfD (referenced to day-ahead prices), the capacity would effectively be sold twice.

C3.72 Clearly, it is possible to address these interactions by prohibiting generation that is in receipt of a FiT CfD from participating in the Capacity Market. However, this raises additional concerns: for example, we would need to forecast the amount and reliability of FiT CfD-supported generation we expect to come forward.

C3.73 We propose to continue working on these issues as the options are developed, though it should be noted that it is likely that these solutions may impact on the efficient design of a Capacity Market.

Question 21: What could we do to mitigate interactions between a Capacity Market (especially if a Reliability Market) and Feed-in with Contract for Difference without diluting the effectiveness of either?

The role of demand side response, storage, price response and interconnection

Role of contracted demand side response and price response

C3.74 In a Capacity Market, a party offering DSR offers to forgo a certain amount of consumption in return for a payment. In some circumstances this forgone consumption can be treated as equivalent to generation. The following options could be used for enabling DSR measures within the Capacity Market (note that more detail on primary and secondary markets is included in 'Primary and secondary markets'):

- **include in the primary capacity market:** DSR measures could be included by offering the flexibility they provide in the primary Capacity Market; and/or
- **include in secondary capacity market:** DSR measures could be included in secondary capacity markets. Secondary markets could be used by providers to reallocate their obligations from the primary capacity market during shorter periods, for example during the scheduled maintenance of a power plant. They therefore offer a

good platform for trading DSR measures that typically cannot offer reliability for long periods; and/or

- **reduce capacity obligations:** DSR measures involving reductions at peak times could be included by subtracting them from suppliers' capacity targets in the primary capacity market.

Role of storage and other non-generation technologies and approaches

C3.75 We envisage that other technologies and approaches, such as electricity storage, would be able to participate in a Capacity Market in the same way as generation capacity, provided they meet the required criteria.

Question 22: How can a Capacity Market be designed to encourage the cost-effective participation of DSR, storage and other non-generation technologies and approaches?

Role of interconnection capacity and providers outside GB

C3.76 In a Capacity Market, the full amount of capacity required is purchased by (or on behalf of) consumers. Since interconnectors – and the non-GB sources of capacity to which they connect – do contribute towards total capacity, we would in principle want them to be able to participate in a Capacity Market.

C3.77 The goal of allowing this participation would be the same as for generation: to ensure that, taking all forms of capacity together, an adequate amount of capacity is built in the most cost-effective form possible, and that this capacity has the desired level of reliability. Where participants in a Capacity Mechanism make their own assessment of the level of reliable capacity each can supply (as is the case, for example, in a Reliability Market) it would be desirable for this to be true also of capacity provided by means of interconnection.

C3.78 The alternative to allowing participation of interconnection and non-GB generation in the Capacity Market would be to forecast the amount of capacity that would be expected to be reliably supplied via interconnection and compensate for any overall shortfall in supply meeting demand in the GB by the delivery of additional capacity domestically. Under this approach, we could in the long run arrive at an inefficient level of interconnection.

C3.79 In considering the role of interconnectors in a Capacity Market, we will need to take into account the provisions of the EU Third Package that concern interconnection.

Functional groupings

C3.80 The institutional and delivery functions required for a Capacity Market are dependent in part on the detailed design of the mechanism, which we are consulting on in this annex. However, the key institutional functions required are set out below.

C3.81 For simplicity these detailed functions are shown as falling into three main categories:

- functions to set the key outcomes of the scheme – i.e. 'setting the rules'. These could involve setting the high-level parameters, such as required level of capacity, and could also involve an advisory function providing technical advice;
- operational functions to carry out the administrative delivery of the scheme – including contract management and providing for market participants to engage with the Capacity Market as required i.e. 'operating the scheme within the rules'; and
- oversight functions – i.e. 'ensuring the rules are adhered to' by all relevant market participants and the operational function.

C3.82 These functions are described in more detail below.

Functions to set outcomes and key technical parameters of the scheme – i.e. 'setting the rules'

C3.83 A Capacity Market would require a number of determinations to be made. On an ongoing basis this would include the total capacity requirement including any desired margin (that is, the total volume of contracts to be purchased).

C3.84 On a one-off basis, and/or reviewed periodically, the technical parameters could include:

- the volume of contracts to be held by each supplier;
- for a Reliability Market, the level of the strike price, and any index used for updating the strike price;
- for a Reliability Market, the choice of the reference market;
- for some forms of Capacity Market, the level of capacity that can be offered by different types of provider, and the regime for administering penalties;
- the lead time and duration for the contracts; and
- if contracts are bought by suppliers, the level and nature of the penalty for a supplier holding insufficient contracts, and any associated appeals mechanism.

C3.85 The required level of capacity and other key technical parameters would need to be centrally determined, drawing on technical advice as necessary.

Functions to ensure the scheme is delivered effectively – i.e. 'operating the scheme within the rules'

C3.86 Operational functions concern operational interaction with the market and practical delivery of the scheme. Detailed operational requirements are particularly dependent on the detail of scheme design. For illustrative purposes, they could include:

- if contracts are procured by a central institution[32], running a central auction function to establish the buy-out price, procuring the required contracts from providers of capacity, financially settling the contracts and passing on the costs and paybacks to consumers;
- if contracts are procured by suppliers in a central auction, running a central auction function to establish the buy-out price, monitoring to ensure suppliers purchase the required number of contracts, and providing clearing services for the financial settlement;
- if contracts are bought by suppliers in bilateral markets, placing and enforcing an obligation on suppliers to hold a certain number of contracts (as determined by the organisation carrying out the central functions), including monitoring to ensure suppliers have taken out the required number of contracts;
- if there are financial or physical back-up requirements, checking that contracts are backed up by physical and/or financial back up as required. This involves checking assumptions that a provider has made about de-rating of capacity (as it appears in the contract) are reasonable, and rectifying this if not;
- if penalties are administered centrally, rather than through call options, the administration of incentives/penalties;
- administering a secondary market to allow trading in contracts for capacity as suppliers adjust their demand forecasts nearer to real time; and
- recovering primary and secondary market administration costs from market participants.

Oversight functions (i.e. 'ensuring the rules are adhered to')

C3.87 Governance arrangements would be needed to ensure there was appropriate oversight and accountability of the above organisations (including organisations carrying out the central and operational functions). In principle such a framework could be established by placing duties, responsibilities and obligations on relevant organisations through a combination of statutory duties, or where a licensing regime exists or could be created, through licence conditions.

32 See 'How and by whom capacity is bought'.

C3.88 Further discussion of the nature of the institutions required to deliver these functions is provided in Chapter 4 of this White Paper. The detailed institutional functions would need to be decided in the light of consultation responses if we decide to proceed with a Capacity Market model. It should be noted that each of the functions could be split between one or more organisations.

Question 23: Do you have any comments on the functional arrangements proposed for managing a Capacity Market?

Triggering the Capacity Mechanism

C3.89 There is a question of whether a Capacity Market should be introduced immediately, or whether its introduction should be triggered – either when a central organisation considers it appropriate to do so, or when a certain pre-set level of forecast capacity is reached[33].

C3.90 Including a trigger mechanism has pros and cons. It gives the option of not triggering a mechanism if it is not perceived to be required at the time. However, it could lead to uncertainty and investment hiatus, prompting pressure to trigger the mechanism to give industry greater investment certainty.

C3.91 Given the long lead times associated with establishing a Capacity Mechanism, the Government is minded to make detailed legislative powers for the chosen type of Capacity Mechanism as early as possible.

C3.92 An annual decision on whether or not to trigger the mechanism could then be taken in time to cost effectively allow the implementation of the chosen Capacity Mechanism.

Question 24: Do you think that a trigger should be set for the introduction of a Capacity Market? If so, how do you think the trigger should be established, and how should it be activated?

Question 25: What is the most appropriate design of Capacity Market for GB and why?

33 Note a Strategic Reserve has an 'in-built' trigger in that reserve is only procured if the market is forecast to bring forward less reliable capacity than ministers deem desirable (see 'Setting the level of required capacity' in Section 2: 'Strategic Reserve').

C.4 International comparisons

C4.1 We have looked at international examples of Capacity Mechanisms in use (or previously used and now discontinued) in various countries around the world. Various types of Capacity Mechanism were studied.

Strategic Reserve

C4.2 Examples of Strategic Reserve were identified in Finland, Sweden, New Zealand and Australia. The example that most closely matches that discussed in this annex is the Swedish Peak Load Reserve (PLR). The PLR was introduced following the liberalisation of the Swedish market in 1996, and concerns that a number of ageing peaking plants (mostly oil) would no longer be able to cover costs and would close leading to shortages.

C4.3 The PLR was conceived to ensure adequate capacity at peak times. Legislation requires that the Transmission System Operator, Svenska Kraftnät (SvK), purchases capacity to be used at times of extremely high demand where the electricity market alone will not deliver adequate capacity. The maximum level of PLR is set in law at 2 GW, though SvK can purchase less than this if it considers it appropriate. Legislation also specifies that PLR can only be used between November and March, as Swedish electricity demand peaks during the winter months. Sweden has recently passed legislation that requires a proportion of the PLR to be made up of demand side resources and will phase out the PLR altogether by 2020. The current PLR comprises mainly oil-fired plants and some DSR (mainly paper mills). PLR is made available to the market at times of tightness at a price just above the most expensive cleared bid in the Nord Pool day-ahead spot market.

C4.4 The main concerns raised with the use of a Strategic Reserve in the GB market are around possible market distortion and the 'slippery slope', where more and more capacity is included in the reserve and removed from the electricity market. The Swedish PLR was developed with these issues in mind, and addresses them in a number of ways. It was designed from the beginning to be time limited (although it has been extended to 2020), which makes it less attractive for investors in new plants and so less susceptible to the slippery slope. The maximum quantity of PLR is specified in legislation, and PLR is envisioned to run very infrequently (in fact it has only ever had to be activated three times). This, together with the fact that it is priced above the highest bid in the market, minimises the risk of market distortion.

C4.5 There are a number of differences between the Swedish system and that being proposed in this annex. Key among these are that the Strategic Reserve proposed for GB is not intended to be a temporary measure (though it would be reviewed in future), and that in Sweden, the vast majority of electricity is traded on the day-ahead spot market. The proposals for Strategic Reserve described in this annex suggest that the price at which the Strategic Reserve is despatched would be set at a fixed price to avoid distorting the market. There are also some similarities with the Swedish system. In particular, we envisage DSR being able to participate fully in a GB Strategic Reserve as long as it can meet the necessary technical criteria.

Capacity Market

C4.6 The North American Reliability Pricing Model (RPM) model used in PJM is an example of a Capacity Market. There is a capacity obligation requiring suppliers to have the resources to meet customers' peak load and provide a reserve. The RPM allows suppliers to meet this capacity requirement through their own generating capacity, or to contract for capacity bilaterally or through PJM's capacity market auctions. Capacity auctions are held three years in advance to allow time for new capacity construction. The initial auction is followed by 'incremental' auctions for each demand year to allow for changes in market dynamics[34].

C4.7 Examples of markets for reliability contracts were identified in Colombia, New England and to an extent in Brazil (although those used in Brazil were significantly different from the Reliability Market proposal discussed in this annex). The closest example to the Reliability Market described in this annex is the one used in Colombia.

C4.8 Colombia makes use of reliability contracts with mandatory physical back up in the electricity market and a secondary market. The contracts have a lead time of between three and seven years and a delivery period of between one year (for existing plants) and 20 years (for new plants). Contracts are bought in a descending clock auction by a central authority on behalf of all consumers and are referenced to the price in a day-ahead spot market similar to the previous England and Wales Pool. The Colombian Pool is the key difference between the Colombian system and the Reliability Market described in this annex and provides a convenient reference price for reliability contracts in Colombia. In Section 3: 'Capacity Market' above we are consulting on the reference price that might be used in a Reliability Market, and whether reliability contracts should have firm physical back-up.

C4.9 In addition to the system differences, it is worth noting that Colombia has a large proportion of hydro power in its generating mix, with the remainder being made up of mainly fossil fuel thermal generation. Colombia is therefore exposed to different issues to those a GB capacity mechanism would need to address. Specifically, Colombia requires sufficient capacity to provide electricity during prolonged dry periods caused by the El Nino phenomenon. In contrast, the key challenge for any future GB Capacity Mechanism will be providing enough generation to cover relatively short periods of high demand and low wind.

34 The rules for the RPM's incremental auctions are available here: http://www.pjm.com/markets-and-operations/rpm/~/media/markets-ops/rpm/rpm-auction-info/rpm-incremental-auction-faqs.ashx

C.5 Comparison of Capacity Mechanism options

Summary

C5.1 The particular characteristics of the GB market mean there is unlikely to be a perfect Capacity Mechanism for our circumstances. The Capacity Mechanism we decide to proceed with will need to be based on assessment of the pros, cons and risks associated with each.

C5.2 Here, for comparative purposes, this section identifies the relative merits of a Strategic Reserve and a Capacity Market, though we recognise there are other forms a market-wide mechanism could take and these remain under consideration.

C5.3 The following sections include a qualitative assessment of these two potential mechanisms against eight criteria, and a quantitative assessment of costs[35].

Assessment against criteria

C5.4 We have assessed these two Capacity Mechanism options against eight criteria. These criteria will also form the basis of our further analysis in the second half of the year:

1. Achieves sufficient security of supply;
2. Cost-effective, practical and feasible;
3. Durable to changes in the GB market, including to the demand side;
4. Robust against the use of market power;
5. Supports supply-side efficiency;
6. Compatible with our market;
7. Consistent with decarbonisation and renewables targets;
8. Compatible with other Electricity Market Reform policies.

Criterion 1: Achieves sufficient security of supply (including investment incentives)

C5.5 A central goal of a Capacity Mechanism is to ensure that the required reliable capacity is in fact created.

C5.6 For a Strategic Reserve, the key concern – highlighted by a wide range of stakeholders – is that it will undermine the incentive for the market to invest in flexible peaking plants. This is because the investment case for such plants, particularly in an electricity market with high levels of intermittent generation, is based on its ability to secure high prices in times of market stress (scarcity rents). If a Strategic Reserve were in place, this creates two problems:

35 This analysis is based on several sources, including De Vries, L.J.: Securing the public interest in electricity generation markets (2004). However, note that the evaluation presented here is the Government's view and does not necessarily reflect that of any particular author.

- at what price does the Strategic Reserve enter the market; and
- how can the price at which the Strategic Reserve enters the market be changed?

C5.7 In principle, the Strategic Reserve should only enter the market when all other capacity has been exhausted – otherwise, it is inefficiently displacing existing capacity from the market. Stakeholders' concern is that, if this were the case, there would be heavy pressure to reduce the price at which the reserve entered the market during extended periods of high prices. Importantly, the mere perception of this risk will tend to disincentivise investment, leading to under-investment and the need to procure ever more reserve – the 'slippery slope'.

C5.8 We have developed the Strategic Reserve option to address this concern as far as possible. Strategic Reserve would only be despatched when prices rise above a certain level – the despatch price. This would be set high enough above the highest long-run marginal cost in the electricity market to minimise distortion, but below VoLL. In this way a Strategic Reserve minimise displacement of any capacity in the electricity market which would otherwise have been made available. In addition, to mitigate concerns that the despatch price would be reduced at times of high prices due to short-term pressures, we propose to ensure any changes could only be made via a defined change process.

C5.9 We envisage that a Capacity Market should, if well designed, provide sufficient security of supply and investment incentives, and should not lead to the 'slippery slope' challenge faced under a Strategic Reserve.

C5.10 The other key challenge in ensuring security of supply relates to the estimates that are required for operating each Capacity Mechanism. All Capacity Mechanisms require an estimate of future demand. A Strategic Reserve also requires an estimate of the capacity that would be brought forward by the market. Both of these estimates are subject to error, increasing the scope for procuring the 'wrong' amount of reliability/capacity. In principle, a Capacity Market would only require an estimate of future demand – though this would not be the case if FiT CfD plants were excluded from the market (see Criterion 8).

Criterion 2: Cost effective, practical, and feasible

C5.11 A Strategic Reserve appears to be a practical and feasible option. An organisation could be mandated to purchase the required reserve capacity through a commercial tendering process similar to the way National Grid currently procures STOR. If the reserve is despatched appropriately, the adverse impact of market distortions could in principle be kept to a minimum. However there are caveats to this – in particular, the risk of over-procurement, and the 'slippery slope'.

C5.12 In contrast, a Capacity Market would require the creation of what is, essentially, a new market. If the market were created through a supplier obligation, then suppliers would need to purchase contracts for capacity, which they could do bilaterally or through exchanges; in either case, there would need to be new machinery to support this trading. In addition, it would presumably take some time for all participants to become familiar with the implications of trading in a Capacity Market.

C5.13 It may be felt that a full Capacity Market would necessarily cost more than a targeted mechanism, since it involves paying for all capacity, whereas a Strategic Reserve means paying for only the incremental capacity needed. However, this analysis is not necessarily correct. A Capacity Market exchanges steady income from the contract premium for reduced revenue elsewhere – for example, in the case of a Reliability Market, by requiring repayment of revenues above a strike price, so in theory the overall costs of either Capacity Mechanism should be the same (though this does require effective detailed design). A Strategic Reserve retains some potential for high prices, but makes them lower and more frequent.

Criterion 3: Durable to changes in the GB market, including increased role for demand side and interconnections

C5.14 GB's electricity generation system is characterised, on the supply side, by a significant proportion of flexible coal and gas thermal generation and, on the demand side, by inflexible consumption. This balance will change dramatically over the next few decades to one of more inflexible and intermittent generation on the supply side but also more responsive demand (including both formal arrangements to reduce demand when required, and a demand market which is more responsive to short-term fluctuations in price).

C5.15 We consider it an essential feature of any Capacity Mechanism that it be robust to these changes, both in the sense that it incentivises the appropriate use of flexible generation and non-generation approaches (including DSR, storage and interconnection); and that, if and when it is no longer needed, it can be removed or evolved into something more reflective of the new demand side market.

C5.16 A Strategic Reserve is robust to some of these changes, in that the organisation charged with procurement can choose the technical characteristics of the reserve to reflect changing needs.

C5.17 A Strategic Reserve could allow DSR to bid to form part of the reserve if it fits the necessary characteristics. However, by providing an external source of reliability which is outside the market, a Strategic Reserve may reduce the broader incentives for consumers to respond to changes in real-time electricity prices. Finally, although a reserve could in principle be reduced, and even eliminated if no longer required, there is a concern that the central organisation tasked with procuring sufficient reserve to ensure a reliable system would find it difficult to decide in a particular year to procure nothing.

C5.18 For a Capacity Market, providers of DSR could also participate, for example, by selling contracts for capacity where they met the necessary characteristics.

C5.19 In addition, a Capacity Market is plausibly more compatible with a future market which has a more liquid and responsive demand side. Since it is a market-wide approach, one could imagine consumers, potentially through suppliers, being more engaged in the decision about the minimum level of reliable supply they require based on the cost to them of differing levels of reliability. Smart Meters could help to enable such a transition.

C5.20 With regard to interconnection, a Strategic Reserve (and some forms of Capacity Market) may not be effective in the presence of significant interconnection as it effectively caps the market price. Since the energy flows in coupled markets are determined by prices, energy could 'leak' or simply not be available if the price in the other market rose sufficiently high. In certain forms of Capacity Market, however, such as a Reliability Market, the market price signals remains, providing the incentive for the interconnector flows to arrive when they are needed; these markets offer the potential to be effective in the presence of interconnection.

Criterion 4: Robust against the use of market power

C5.21 In a tight electricity market, generators may be incentivised to withhold capacity in order to drive up electricity prices further. This could occur because in scarcity conditions the withdrawal of a small amount of capacity can have a significant impact on the market price. Should it occur, such exercising of market power would be difficult to identify and could have significant implications for security of supply.

C5.22 Both a Capacity Market and a Strategic Reserve could be designed in a way that removes the incentives for generators to artificially increase prices. In this regard, they both have the potential to robustly guard against abuse of market power in the electricity market as a helpful side effect.

C5.23 The exact extent of the robustness depends upon the level of the strike price. A Strategic Reserve would typically cap the prices at the despatch price. In order to avoid significant impact on the electricity market the despatch price would be chosen at a high level (discussed above).

C5.24 A Capacity Market, on the other hand, could be designed in a way that does not blunt price signals by capping market prices. In the example of a Reliability Market, if one of the generators has an outage, the other generators that make up for this by producing more than required by their reliability contracts can keep the additional revenues from selling this output at higher prices. Consumers are hedged against this because a reliability contract obliges the plant that had an outage to pay back the difference between the strike price and the price in the reference market. Reliability contracts can therefore use a lower strike price than Strategic Reserve contracts without distorting market signals. To the extent that the strike prices are lower, a Reliability Market would thus be likely to offer stronger protection against abuse of market power than a Strategic Reserve. Similar arguments may be made for other types of Capacity Market, depending on the incentive structure used.

C5.25 We might also be concerned about the potential for exploitation of market power in the procurement of capacity, whether in the tender for Strategic Reserve or in a Capacity Market.

C5.26 A Strategic Reserve appears to be less susceptible to this kind of manipulation, since only an incremental amount of capacity is being acquired.

C5.27 A Capacity Market would need to be carefully designed to avoid being susceptible to exploitation. For example, a central determination of capacity could lead to an inelastic demand for capacity, and the market could then be subject to similar risks as experienced in the current market[36]. Still, the problem should be less severe because new entrants could compete in the Capacity Market (see criterion 5 below for more detail).

C5.28 Additionally, a Capacity Market, particularly in the form of a Reliability Market, would be innovative and its design may offer unforeseen loopholes to allow participants to exploit the system. Again, sound design would reduce the risk; but this risk is likely to be higher than for a Strategic Reserve.

Criterion 5: Supports supply-side efficiency

C5.29 Just as one of the goals of the New Electricity Trading Arrangements (NETA) was to provide the correct incentives to market participants to despatch their generators efficiently, we assume a requirement on any Capacity Mechanism is that it provides the required capacity efficiently.

C5.30 As noted, a Strategic Reserve requires the central determination of at least two parameters (peak demand and forecast capacity). A Capacity Market will require either one or two parameters to be forecast (depending on the treatment of FiT CfD plants). Getting these forecasts wrong will tend to reduce supply-side efficiency.

C5.31 With regard to new market entrants, a Strategic Reserve, if properly designed, does not appear to hinder market entry by new generators. In principle, new entrants could enter the reserve mechanism if contracted sufficiently far in advance. However, the new entrant would be bidding into a different market (and a small one) since the reserve is not permitted to participate in the electricity market. On the retail side, the cash out penalty imposed on a supplier who is short (i.e. uses more energy than it expected) would be capped (at the reserve despatch price). This might be helpful to small suppliers.

36 Inelastic demand is where the demand for a good or service in a market is relatively unresponsive to changes in the price of that good or service. When demand is inelastic, the percentage change in quantity demanded is less than the percentage change in price.

C5.32 A Capacity Market could in principle be helpful to new market participants, again if contracted sufficiently far in advance to allow new build. These new entrants would face less volatile revenues on which to base their investment decisions, and the payment for the capacity contract would result in a lower cost of capital. This could help smaller generators who were unable to cope with risks as well as larger players. One downside might be the generator's risk of not being able to pay the required penalty when required (for example, if the generator was offline) and the consequent counter-party risk faced by suppliers. This may prevent small generators offering contracts for the full amount of their reliable capacity. This could be mitigated by a liquid secondary market, which would allow contract signatories to trade out of positions, e.g. to cover periods of maintenance.

C5.33 On the retail side, if the contracts in a Capacity Market were procured by suppliers, then suppliers would face the additional costs of procurement. However, their costs in the electricity market should be limited, which reduces their risks.

C5.34 There is concern that perceived problems of the current market owing to the prevalence of bilateral, over the counter (OTC) trading – namely, a lack of transparency and liquidity – will simply be replicated in any new Capacity Market (if it is run through a supplier obligation) and that this will be a barrier to entry for new, independent suppliers. In addition, suppliers will face operating costs for trading in the new market. Presumably, contracts for capacity in a Capacity Market will be a more standard product than electricity (because there is not one market every half hour) and therefore could be offered on more liquid exchanges, promoting transparency. Notwithstanding that presumption, these are real issues, which it may or may not be possible to address with suitable design.

Criterion 6: Compatible with our market

C5.35 The GB market has a number of distinguishing features which impact on a Capacity Mechanism – including that most energy is transacted in physical forward markets through bilateral contracts, and that the market is dominated by vertically-integrated players. Both of these market features present particular issues for a Capacity Market.

C5.36 In the case of a Reliability Market, reliability contracts – whether procured centrally, or through obligations – were designed for systems with a single, close to real-time, physical market with separation of generators and retailers. To work in our market, they would need to be adapted. We believe that the adaptations are possible (for example, we could make use of existing day-ahead auctions) but this is not without design risk. For other forms of Capacity Market, we would need to ensure that the incentive structure was compatible with the GB market.

C5.37 The fact that our market is strongly vertically integrated is also a challenge. If the two parties to a contract for capacity are one company, then the option payment would simply be a transfer of money within that company, and it is not clear what the incentive would be. Again, there are potentially ways to address this – for example by requiring option payments to be returned to customers[37].

C5.38 A Strategic Reserve should not be significantly affected by the presence of forward contracting and vertical integration.

Criterion 7: Consistent with decarbonisation and renewables targets

C5.39 A Capacity Market offers incentives to any provider of reliable capacity, including low-carbon generation. However, the impact of the choice of Capacity Mechanism on decarbonisation and renewables targets seems small.

Criterion 8: Compatible with other elements of the Electricity Market Reform package

C5.40 Interactions with other elements of the Electricity Market Reform package are an important consideration for Capacity Mechanism design. In particular, the FiT CfD could introduce interactions with the proposed Capacity Mechanisms.

C5.41 The Strategic Reserve operates 'outside' the market and it is assumed that, as participants in the reserve will likely be fossil-fired peaking plants, recipients of FiT CfD will not be directly affected.

C5.42 However, the Capacity Market could interact with low-carbon generation support. In particular, both the Capacity Market and the FiT CfD provide payments for some version of capacity. The precise issues that arise depend on the form of FiT CfD, and are discussed in more detail above in Section 3: 'Capacity Market', under 'Interaction with Feed-in Tariff with Contract for Difference'. Views are welcomed on the best way to mitigate this.

Cost-benefit analysis of Capacity Mechanism options

C5.43 Here, for comparative purposes we compare a Strategic Reserve with the Reliability Market form of Capacity Market, though we recognise there are other forms a market-wide mechanism could take and these remain under consideration. More detailed analysis is included in the Impact Assessment published alongside this annex.

Summary

C5.44 Key conclusions from the cost-benefit analysis are:

- the modelled differences in the Net Present Value (NPV)[38] of a Strategic Reserve or a Reliability Market are relatively low in absolute terms compared to other Electricity Market Reform proposals. This is not surprising as both a targeted or a market-wide Capacity

37 See 'Impact of vertical integration on availability signals' in Section 3: 'Capacity Market'.

38 Net Present Value' (NPV) is a way of accounting for the sum of a project's future cash flows in today's terms – showing the difference between a future stream of benefits and costs. NPV recognises that society would prefer £1 today to £1 in the future – this is known as 'time preference'. Therefore due to time preference, future cash flows are 'discounted' (using a discount rate) when calculating NPV.

Mechanism are at least theoretically capable of producing exactly the same outcome if designed efficiently. Any differences are likely to be due to the way that either mechanism is designed;

- modelling indicates a net cost associated with either Capacity Mechanism. This is sensitive to the assumptions made around the VoLL. If a higher estimate of VoLL is made then both mechanisms compared here have a positive NPV;
- in addition, market failures (discussed in Chapter 3 of this White Paper and in the Impact Assessment) are not included in the Redpoint model used for this analysis and would tend to increase the benefits of either of these potential Capacity Mechanisms.

Analysis

C5.45 We have carried out analysis of the electricity market to look at the impacts of these two potential Capacity Mechanisms – a Strategic Reserve despatched as last resort, and a Reliability Market. Our analysis includes FiT CfD providing low-carbon generation support. More detail can be found in the accompanying Impact Assessment published alongside this White Paper. The net benefits are shown in Figure C13.

Figure C13: NPV for Feed-in Tariff with Contract for Difference scenario, 2010-2030, £m (2009 real)

	Strategic Reserve **£m**	**Reliability Market** **£m**
NPV (VoLL = £10,000/MWh)	-643	-837

C5.46 A Reliability Market results in slightly more investment in new CCGTs which crowds out old coal, while a Strategic Reserve sees slightly less investment in CCGTs, coal stays on slightly longer, and there is some investment in cheaper OCGTs. This means that with a Reliability Market we have higher capacity and generation costs, but slightly lower carbon costs as the mix is slightly cleaner.

C5.47 Our analysis, carried out by Redpoint, suggests there is some net cost associated with either type of mechanism evaluated here. This is simply because the model produces an “optimal” level of security of supply, given a specific value of VoLL. Our model uses a VoLL of £10,000/MWh[39]. By imposing a constraint that margins are increased to 10%, this will by definition lead to a negative NPV in the modelling. Note that the argument for a Capacity Mechanism rests on the fact that this

39 Estimates of VoLL are very uncertain. Oxera, an economics consultancy, publishes a range of estimates for VoLL between £5,000/MWh and £30,000/MWh. For more see ‘What is the optimal level of electricity supply security?’ (Oxera, 2005)

theoretically perfect market does not exist in practice (and that investors do not believe that it exists) because of the market and regulatory failures mentioned below and described in more detail in Chapter 3 of this White Paper and in the Impact Assessment[40].

C5.48 The differences between the two are not particularly significant. However, this is sensitive to the assumptions around the average VoLL. If we use a VoLL of £30,000/MWh, at the top end of the range for VoLL, as opposed to £10,000/MWh then both mechanisms have a net positive NPV as is shown in Figure C14.

Figure C14: NPV for Feed-in Tariff with Contract for Difference scenario, 2010-2030, £m (2009 real)

	Strategic Reserve **£m**	**Reliability Market** **£m**
NPV (VoLL = £30,000/MWh)	193	50

C5.49 In addition, there are a number of potential market failures, including missing money, which mean that the market will not deliver the optimal level of investment. These market failures are not incorporated into the model and to the extent that they lead to insufficient investment in new capacity, they would tend to increase the benefits of either of the Capacity Mechanism options.

C5.50 The costs and benefits of any Capacity Mechanism in practice will depend on the design of that mechanism. The design of any mechanism is necessarily complex and as part of the implementation of the mechanism, will require careful further thought to minimise distortions. The modelling and associated cost/benefit figures are a best attempt to simulate the impacts of a Capacity Mechanism, but the practical details of implementation will inevitably have an impact on the final costs and benefits.

C5.51 The costs and benefits here do not include the estimated institutional costs for a Capacity Mechanism. These are assessed with other institutional costs in the Impact Assessment accompanying this White Paper. The institutional costs are however likely to be dependent on the design of the mechanism. In addition, there is likely to be a cost to companies of participating in any Capacity Market.

Question 26: What are your views on the costs and benefits of a Capacity Mechanism to industry and consumers?

40 For our future modelling, we will examine whether it is possible to reflect the impact of market failures on capacity margins and energy unserved.

Question 27: Which Capacity Mechanism should the Government choose for the GB market and why?

C.6 Consultation Questions

Targeted Capacity Mechanism

Question 1: Does this table capture all of your major concerns with a targeted Capacity Mechanism? Do you think the mitigation approach described will be effective?

Question 2: How long should the lead time for Strategic Reserve capacity procurement be and why?

Question 3: Should the length and nature of contracts procured by the Strategic Reserve procurement function be constrained in any way?

Question 4: Which criteria should providers of Strategic Reserve be required to meet?

Question 5: How can a Strategic Reserve be designed to encourage the cost-effective participation of DSR, storage and other forms of non-generation technologies and approaches?

Question 6: Government prefers the form of economic despatch described here. Which of the proposed despatch models do you prefer and why?

Question 7: How would the Strategic Reserve methodology and despatch price best be kept independent from short-term pressures?

Question 8: Do you agree that a Strategic Reserve should be periodically reviewed? If so, who would be best placed to carry out the review and how often should it be reviewed?

Question 9: Into which market should Strategic Reserve be sold and why?

Question 10: Do you have any comments on the functional arrangements proposed for managing a Strategic Reserve?

Question 11: Given the design proposed here and your answers to the above questions, do you think a Strategic Reserve is a workable model of Capacity Mechanism for the GB market?

Market-wide Capacity Mechanism

Question 12: How and by whom should capacity in a GB market be bought and why?

Question 13: What contract durations would you recommend for a Capacity Market?

Question 14: How long should the lead time for capacity procurement be? Should there be special arrangements for plants with long construction times?

Question 15: Should there be a secondary market for capacity? Should there be any restrictions on participants or products traded?

Question 16: What are the advantages and disadvantages of making a central, administrative determination of (i) the capacity that can be offered into the market by each generator; (ii) the criteria for being available; and (iii) the penalties for non-availability? In outline, how would you suggest making these determinations?

Question 17: How should the reference market for reliability contracts be determined and what would be an appropriate reference market if it is set by the regulator? How could any adverse effects of choosing a particular option be mitigated?

Question 18: For a Reliability Market, how should the strike price be determined? If using an indexed strike price, which index should be used?

Question 19: For a Reliability Market, what level of physical back up (if any) should be required for reliability contracts and how should it be monitored?

Question 20: Do you agree that a vertically integrated market potentially raises issues for the effectiveness of a Reliability Market? If so, how should these issues be addressed?

Question 21: What could we do to mitigate interactions between a Capacity Market (especially if a Reliability Market) and Feed-in Tariff with Contract for Difference without diluting the effectiveness of either?

Question 22: How can a Capacity Market be designed to encourage the cost-effective participation of DSR, storage and other non-generation technologies and approaches?

Question 23: Do you have any comments on the functional arrangements proposed for managing a Capacity Market?

Question 24: Do you think that a trigger should be set for the introduction of a Capacity Market? If so, how do you think the trigger should be established, and how should it be activated?

Question 25: What is the most appropriate design of Capacity Market for GB and why?

Capacity Mechanism Assessment

Question 26: What are your views on the costs and benefits of a Capacity Mechanism to industry and consumers?

Question 27: Which Capacity Mechanism should the Government choose for the GB market and why?

Annex D – Renewables Obligation transition

Introduction

D.1 The UK has some of the best natural renewable energy resources in Europe. The Government is determined that the UK should become the location of choice for inward investment in renewables, and that the UK should have the fastest improving growth in renewables deployment across Europe. The proposals in this White Paper will enable us to establish a stable and transparent long-term financial framework for renewables. We will deliver the growth required to achieve our ambitions by mobilising investment from the private sector.

D.2 The Renewables Obligation (RO) was introduced in 2002 to support the deployment of renewable electricity. It requires suppliers to submit an increasing number of Renewables Obligation Certificates (ROCs) in respect of each megawatt hour of electricity they supply, or pay a buyout price. The proceeds from the buyout payments are recycled to suppliers in proportion to the number of ROCs they submit. The RO is administered by Ofgem which issues ROCs to accredited renewable electricity generators in respect of their eligible renewable output.

D.3 The RO has successfully supported the deployment of increasing amounts of renewable generation, from 3.1 GW in 2002 to 8 GW in 2009, and encouraged new renewable technologies to evolve, like wave and tidal. However, even if the scheme's current 2037[1] end date were extended, the RO would not be the most cost-effective mechanism to incentivise post-2020 deployment. Therefore, the proposals in this White Paper set out the framework for supporting renewables in the long term.

D.4 In responding to the Electricity Market Reform consultation document[2], many stakeholders agreed with our assessment of the importance of a clear and stable transition period. The Government recognises that there is a significant existing renewable electricity investor community, and we aim to prevent a hiatus in renewables investment while the new arrangements are being put in place. Having sought industry views on the best means to transition to a new scheme, this Annex sets out the transition arrangements for renewables.

D.5 The Government supports the principle of no retrospective change for renewables investments, and through the consultation process have listened to industry views on the best way to transition to the Feed-in Tariff with Contract for Difference (FiT CfD). With these

1 Currently, the Northern Ireland Renewables Obligation is subject to a 2033 end date.

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

vintaging[3] arrangements we recognise the importance of maintaining industry confidence and stable conditions for investment decisions made on the basis of RO support.

D.6 The arrangements for transition are based on the principles of transparency, longevity and certainty. This Annex sets out in full how the RO will operate to 2037. The arrangements are subject to statutory consultation requirements set out in section 32L of the Electricity Act 1989[4], and Parliamentary and EU State Aid approval.

D.7 The new market arrangements are intended to start in early 2014. During the transition period, support will still be available under the RO. This Annex sets out the arrangements for:

- RO support to 2017:
  - a choice of scheme for new renewables generation projects;
  - some limited grace periods; and
  - provisions for offshore wind phasing.
- RO support from 2017:
  - RO is closed to new generation;
  - RO calculated by headroom until 2027, then Fixed ROC to 2037;
  - all technologies will be grandfathered in the vintaged RO in 2017;
  - provisions will be made for additional capacity; and
  - Non-Fossil Fuel Obligation (NFFO) generation will be treated consistently with other RO generation.

D.8 The RO currently operates as three separate mechanisms working together – the England and Wales RO, the Scottish RO, and the Northern Ireland RO (NIRO). All of the jurisdictions are committed to support for renewables. Whether, or the extent to which, the Devolved Administrations join the new support scheme for low carbon is subject to separate discussion.

D.9 The proposals for RO Transition have been discussed by a Steering Group comprising policy advisors and technology experts from the UK Government and the Devolved Administrations. We will continue to work closely with the Devolved Administrations to ensure that the transition arrangements are simple and transparent across all three RO schemes. We have also discussed the proposals with a wide range of industry stakeholders, including utility companies, independent generators, supply chain manufacturers and existing and potential investors. The proposals have been broadly welcomed.

3 'Vintaging' the Renewables Obligation (RO) system means that it will no longer be open to accreditation for new stations. The closure of the RO to new stations will create a closed pool of capacity which will decrease over time as we approach the end date for the RO of 31 March 2037.

4 http://www.legislation.gov.uk/ukpga/1989/29/contents.

Context

D.10 The current RO is designed to provide up to 20 years of support for large-scale renewable electricity projects, and will run until 2037. The RO will remain open until 31 March 2017, the point at which the length of support offered begins to reduce.

D.11 After 31 March 2017, projects receiving support under the RO will continue to do so (subject to the maximum 20 years support and 2037 end date for the RO). From 1 April 2017, the RO will be closed to new entrants. The RO and all accredited capacity within it will be 'vintaged'.

D.12 The FiT CfD mechanism for low carbon is intended to be introduced in 2014. After introduction of the FiT CfD, new renewables generators will have a choice of support mechanism, subject to the restrictions set out below, up to 31 March 2017 when the RO closes to new accreditations.

Government decision

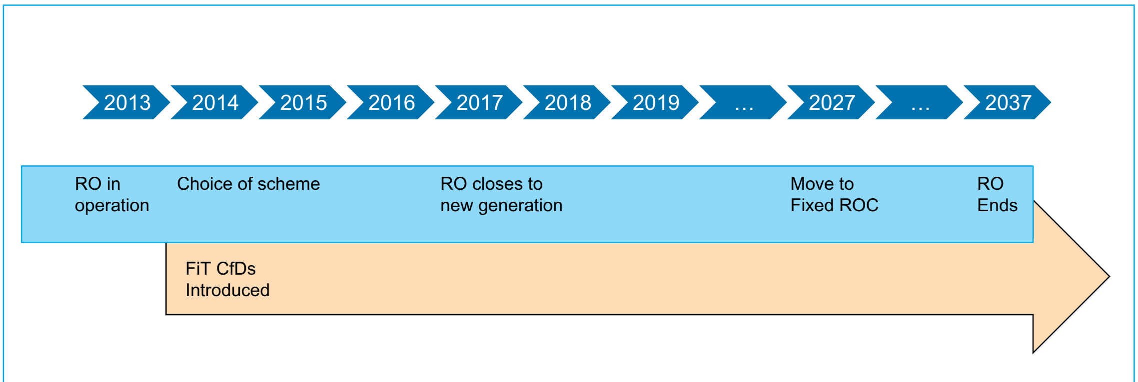
D.13 Some respondents to the consultation requested that the RO should remain open to new accreditations beyond 2017. We have, however, chosen to remain with the 31 March 2017 RO closure date because:

- the RO is subject to a 2037 end date, so any accreditations after 31 March 2017 would receive less than 20 years' support; and
- if the RO were open later than 2017, it would be necessary to hold another banding review in 2017, therefore generators would not know post-2017 tariffs until 2015-16 at the earliest. The intention is to start letting contracts under the FiT CfD in 2014. This should mean that investments are not delayed during the transition period as there will be transparency around the support levels in the lead up to 2017.

D.14 We have made other provisions to address specific concerns around transition timing (see the sections below on the Choice of Scheme, Grace Periods and Offshore Wind Phasing).

D.15 The timeline for the renewables transition is shown in Figure D1.

Figure D1: Timeline for the Renewables Obligation Transition



Renewables Obligation support up to 2017

D.16 The RO will close to new accreditations on 31 March 2017. Our intention is that the new support scheme for low-carbon generation will be introduced in 2014.

D.17 Requiring all renewables generation to accredit under the RO only until 31 March 2017 would have the benefit of simplicity. However, for those who would only invest under a new scheme which gave more revenue certainty, offering a choice of scheme would provide the opportunity to invest at an earlier stage, allowing investment to continue.

D.18 The consultation asked stakeholders whether, as part of the RO transition arrangements, they would like a choice of scheme before the RO closes on 31 March 2017. A number of stakeholders also asked whether a choice would be available to existing generators.

Preferred option for new generation and existing generation

New Generation

D.19 The vast majority of stakeholders expressed a preference for a choice of mechanism before 2017. A limited number of stakeholders expressed the view that offering a choice would create additional uncertainty and complexity.

D.20 As suggested by most stakeholders, once the new scheme is introduced, new renewable generation will have a one-off choice of support mechanism up to 31 March 2017. Once accredited under the RO, a generating station will not be permitted to move to the new scheme at a later date.

D.21 Similarly, this will apply to additional capacity. Once the new scheme is introduced, RO accredited generators who add additional capacity up to 31 March 2017 will have a one-off choice of mechanism for the additional capacity (i.e. the RO or the FiT CfD). As set out below, the original accredited capacity will continue to be supported under the RO.

D.22 Currently, generating stations that have a total installed capacity of 5 MW or less, and meet the relevant eligibility criteria, are able to opt for accreditation under the RO or the small-scale Feed-in Tariff FiT. Therefore additional capacity of less than 5 MW that is added to an RO accredited generating station in the period from the introduction of the new scheme to 31 March 2017, will not be eligible to opt for a FiT CfD if, at the time it is commissioned, it is eligible for the small-scale FiT. We are minded that any additional capacity which would be ineligible for the small-scale FiT will be eligible to opt for the FiT CfD on the same terms as all other eligible capacity.

Existing generation

D.23 Some stakeholders suggested that providing existing projects the same choice between the RO and the FiT CfD, as new projects would provide reassurance to investors.

D.24 However, allowing an open choice for existing projects to transfer to the FiT CfD has the potential to destabilise the RO mechanism and would make it more difficult to set the obligation level each year. Some stakeholders have suggested that the potential for a free transfer might reduce investors' confidence rather than increase it.

D.25 Existing generation will therefore continue to be supported under the RO and, to ensure ongoing RO stability, existing generation will not be permitted to transfer to the new scheme.

Administering scheme choice to 2017

D.26 During the transition period, the level of obligation under the RO will continue to be calculated annually on the same basis as at present.

D.27 We intend to take a light-touch approach to administration in the transitional period, and do not intend to introduce additional requirements on generators to inform us in advance of their choice of scheme, or to pre-accredit for either scheme. We believe that this will have a limited impact on the calculation of the obligation and that any risks posed are managable, but we will keep this under review.

D.28 Generation for which a contract has been signed to receive support under the new FiT CfD mechanism will not be eligible to accredit under the RO.

Grace periods

D.29 The RO closes to new generation on 31 March 2017. However, a number of respondents to the consultation expressed concern over what would happen if that deadline were missed due to factors beyond a developer's control.

D.30 We have offered 'grace periods' for generators under previous RO reforms, such as the introduction of banding in 2009. In principle, these are to protect generators who have taken an investment decision on the basis of support which they are then unable to access due to factors which they could not have foreseen.

D.31 Some respondents requested more significant grace periods, for example until 2020, for generators who may have met certain pre-accreditation requirements. This was on the grounds of the significant timescale uncertainties and risks during construction, in particular for offshore wind. Full details of how grace periods will be exercised are still being considered.

Preferred option for grace periods

D.32 Given that generators will have approximately six years of warning of the date of closure of the RO, and we are offering a choice of scheme in the years before the RO is closed, any generators that feel at significant risk of missing the 31 March 2017 date will have the option of choosing support under the new FiT CfD mechanism in the first instance.

D.33 However, we accept that some projects may be at risk of missing the 31 March 2017 date due to factors beyond their control, such as a delayed grid connection, and recognise that this possibility cannot be reliably quantified and will affect the risk profile of the project.

D.34 Therefore we will offer strictly defined grace periods aimed at those generators whose business case has been based on support under the RO, but whose accreditation is delayed beyond 31 March 2017 by factors beyond their control. This will be limited to a delay in grid connection instigated by the transmission or distribution operator, or a delay in the planned installation of radar necessary to satisfy planning conditions for wind generation projects, in each case where the originally agreed completion date was before 31 March 2017.

D.35 The end date of the RO will not be extended beyond 2037 for those generators benefiting from the grace period.

D.36 This would mean that developers faced with these risks that they cannot control or quantify, are better able to make an investment decision and a choice of support scheme based on calculated risks. This should therefore help to avoid a delay in investments.

D.37 We will put in place evidence requirements that operators will need to demonstrate they have met if these grace periods are to be exercised.

Offshore wind phasing

D.38 The Renewables Obligation (Amendment) Order 2011 (ROO 2011) allows generators of offshore wind stations to phase their RO support, with each phase being eligible for up to 20 years support subject to the end date of the RO.

D.39 Under phasing, generating stations continue to accredit in the same way as at present. However the ROO 2011 imposes a new requirement for them to register turbines in order to receive ROCs on the electricity generated by them. Generators are able to register up to five phases of turbines over a maximum period of five years, with the first phase being at least 20 per cent of the total accredited capacity of the generating station.

D.40 It is likely that a number of stations accredited under the RO will not have planned to finish registering all their phases prior to 2017, and we need to address how to treat those unregistered turbines.

Preferred option for offshore wind phasing

D.41 A number of stakeholders suggested in response to the consultation that phasing should be allowed to continue under the RO after 2017 and, given that any phases registered after 2017 would receive less than 20 years of support (due to the end date of the RO in 2037), we should either extend the RO until 2040, or have increased ROC rates over a shorter timescale for the later phases.

D.42 However, as outlined in this Annex, the RO will close to new accreditations and additional capacity from the 1 April 2017 and we want this to be consistent across all technologies. Consequently, no new offshore wind phases will be permitted to register under the RO after 31 March 2017.

D.43 Generators will instead be eligible to participate in the FiT CfD on the same terms as all other eligible technologies for any remaining turbines that will not be registered under the RO by 31 March 2017. Generation for which a contract has been signed to receive support under the new FiT CfD mechanism will not be eligible for the RO.

D.44 We appreciate the need for early understanding of the revenue under the new FiT CfD mechanism in order for these projects to progress. The Government is considering measures to provide technologies with early certainty, as outlined in Chapter 8 of this White Paper.

D.45 We understand that some generators may wish for their entire station to remain in the RO rather than receive support split between two mechanisms. Therefore accredited generators will be able to register all the remaining unregistered turbines that constitute the consented capacity of the generating station under the RO on or before 31 March 2017, in order to continue to receive support under the RO mechanism for electricity generated by those turbines. The 20-year support period will begin from the point of registration. The lifetime of the RO will not be extended beyond the current 2037 end date.

D.46 The administration of a FiT CfD for wind generation will require registered and approved metering to give output readings. We anticipate that these can be calculated on a pro-rata basis using the meters that are already required for wind farms.

Box D1: Example case study

A 100 MW wind farm accredits under the Renewables Obligation (RO) in January 2016, at which time it registers its first phase of 20 MW. A second phase of 35 MW is registered in September 2016. On 31 March 2017 a number of turbines equating to 45 MW would remain unregistered. The developer can choose either to:

- register all the remaining turbines under the RO on 31 March 2017 and receive support for the entire station from the RO mechanism. The 20 year clock for all the remaining turbines will begin on 31 March 2017 and the RO support for those turbines will end on 31 March 2037; or
- sign a FiT CfD contract for the remaining 45 MW of the station. The turbines already registered will remain in the RO and each phase will receive the full 20 years of support from the point at which the phase was registered; or
- a combination of the two. Register some of the turbines that make up the remaining 45 MW under the RO on 31 March 2017 and sign a FiT CfD for the turbines that are not registered.

Renewables Obligation support from 2017: The Vintaged Renewables Obligation

'Vintaging' the Renewables Obligation

D.47 The RO will be closed to new accreditations and additional capacity from 1 April 2017. All projects accredited under the RO will receive their full 20 years of support (subject to the end dates set in the RO). Therefore, the entire RO system will be 'vintaged' from 1 April 2017.

D.48 'Vintaging' the RO system means that it will no longer be open to accreditation for new stations or to support the additional capacity commissioned after 31 March 2017 at accredited stations. The closure of the RO to new stations will create a closed pool of capacity which will decrease over time as we approach the end date for the RO of 31 March 2037.

D.49 In the course of the consultation, concerns were raised about triggering provisions (such as 'change in law' clauses) in existing Power Purchase Agreements (PPAs) and in existing project financing arrangements. While it will depend on the particular circumstances and terms of each contract as to whether its provisions are triggered, the desirability of avoiding triggering change in law clauses or other default provisions was one of our considerations when designing these vintaging arrangements.

D.50 With these vintaging arrangements we recognise the importance of maintaining industry confidence and stable conditions for investment decisions made on the basis of RO support.

Calculating the Obligation post 2017

D.51 In closing the RO to new entrants from 2017, we will continue to calculate the Obligation each year.

D.52 The Obligation is currently set as the greater of either a fixed target, rising to 15.4 per cent by 2015[5], or our estimated generation plus 10 per cent headroom.

D.53 In the Electricity Market Reform consultation document, we set out three options for the continued calculation of the obligation:

- **option A** – no change to current arrangements; or
- **option B** – move to a headroom only mechanism; or
- **option C** – fix the price of a ROC, with Government buying these direct from generators.

D.54 Through the consultation process, we have made it clear that option A is not acceptable. It could result in consumers paying for 15.4 per cent generation through the RO, even in the late 2020s and early 2030s, when we expect there to be lower levels of RO eligible generation since new projects will receive FiT CfD support, and old projects will only receive RO support for 20 years with a large number dropping out from 2027.

D.55 A few respondents to the consultation asked for option A, but renewables trade associations and other stakeholders have agreed that this option is not tenable. However, they are split between options B or C.

D.56 Proponents of the 'headroom only' option argue that it is the least disruptive to current PPAs, and therefore provides the most certainty to existing investors. It also maintains some incentive for suppliers to continue to purchase intermittent generation, an issue which has been raised by several independent generators.

D.57 However, it does mean that we would continue to set the Obligation each year, through to 2037, which would impose an annual administrative cost. More importantly, there is concern that, as we near 2037, the Obligation would be set on an ever decreasing pool of generators. Should one or more of these suffer a prolonged outage, or a lower than expected load factor (e.g. a low wind year) then the Obligation will have been set too high, and consumers would overpay.

D.58 Fixing the price of a ROC turns the RO into a Premium Feed-in Tariff (PFiT). Investors with projects in the pipeline say that this gives them certainty over the ROC income, and allows them to access the full value of the ROC, rather than having to take a discount through a PPA with a supplier.

5 The Northern Ireland Renewables Obligation rises to 6.3 per cent by 2015.

D.59 It also allows them to access the RO income stream on, for example, a quarterly basis, rather than up to an 18 month lag, without having to pay a premium. Finally, it also means that banks/investors know that they will receive the full value of the ROC all the way to 2037, without worrying that the final few years could be volatile and potentially subject to regulatory risk (for example, if the ROC price spiked, some investors have stated the fear that we would amend the RO in the 2030s).

D.60 However, several generators have voiced concern that PPAs for their existing assets could be adversely impacted if we went down this route, claiming that suppliers could use 'change of law' clauses to terminate/amend the terms. This in turn could also lead to banks citing 'adverse impact' clauses, which would allow them to force the refinancing of projects. As many RO investments reached financial close ahead of the credit crunch, developers say that they are concerned that banks may seek to use this as an excuse to call in loans and refinance on higher terms.

Preferred Option for calculating the Obligation post 2017

Headroom then Fixed Renewables Obligation Certificates from 2027

D.61 In the light of comments arising from the consultation, we have decided on a hybrid option – keeping with headroom (potentially with the fixed target underpin) until 2027, when a large number of projects are dropping out, and then switching to a fixed ROC for the final 10 years of RO support, to limit over-payment by consumers and provide a certain stream of ROC income to generators.

D.62 We believe the hybrid approach provides the best possible balance between providing long-term certainty over ROC income whilst minimising the disruption to current PPA arrangements. It is unlikely that there will be many projects that currently have PPAs beyond 2027.

D.63 We will set the value of the fixed ROC now, to give certainty for investors, at the long term value of a ROC which is the buyout price plus 10 per cent headroom (roughly £41 per ROC at current prices).

D.64 We have raised this hybrid option with a range of stakeholders across the renewables industry and it has been welcomed. In their response to the consultation, Renewable UK stated that they "are open to the possibility of a hybrid system". The finance community has also indicated that it would be an acceptable way to ensure the value of the ROC, especially in the latter years of the mechanism. The Low Carbon Finance Group stated in response to the consultation that "switching from guaranteed headroom to a fixed price post 2027 would be acceptable, as existing projects are protected and new RO projects built in the transition period can take into account the post 2027 pricing".

D.65 Some respondents expressed concern about the availability of PPAs if there were a fixed ROC and no obligation on suppliers. Under our proposal, the Fixed ROC would be introduced in 2027, and the obligation on suppliers would continue to exist until that date.

Impact on the electricity price

D.66 When investing under the RO, the value of the ROC provides only part of the generator’s income stream. They also receive a price for the electricity they sell.

D.67 Under the vintaged RO, generators will continue to sell their power, and will continue to be exposed to the electricity price.

D.68 A number of stakeholders have queried how the package will impact on long-term wholesale electricity prices and therefore on the exposure of renewable generators operating within the RO mechanism. Some stakeholders requested that the Government take additional measures to either stabilise the electricity price for RO generation, or provide some recompense for the additional uncertainty caused by the unknown impact of the package on electricity prices.

D.69 The RO is a support scheme which ensures that generators receive a mixture of variable income (the wholesale electricity price) and income which is considered fixed (the ROC value), and investment decisions under the RO are made on that basis. Generators and investors are therefore expected to assume a level of price risk, including upside.

D.70 A number of factors affecting long-term electricity prices will remain constant regardless of the introduction of the package, such as the increasing market share of intermittent generation. The prevailing capacity margin in the market will also continue to impact on electricity prices.

D.71 The modelled impact of the proposals on long-term UK electricity prices, in addition to current policy, shows that prices will rise even without policies, due to increasing wholesale energy and carbon costs. In the longer term, prices fall in a decarbonised electricity system, relative to a higher carbon intensity electricity grid baseline, because the price setting technologies on the system will have lower marginal costs and are less exposed to assumed rises in fossil fuel and carbon costs.

D.72 Wholesale electricity prices are likely to rise with the introduction of the Carbon Price Floor. RO generators will benefit from exposure to any higher price due to this policy in the shorter term.

D.73 The Government is consulting on options for the design of a Capacity Mechanism. Of these options, the Strategic Reserve, as modelled, would have little or no additional impact on electricity prices, depending on how it was implemented. If the Capacity Market option were to introduce more capacity than would otherwise have been built, then overall electricity prices would be reduced. RO generators may be able to participate in a Capacity Market mechanism, and if so, would receive additional revenue through that source, depending on their ability to despatch. Further detail on the options for Capacity Mechanism design can be found in Annex C.

D.74 As the package will not significantly impact expected income streams over the lifetime of a project, and should not increase the difficulty of forecasting prices, the Government is not minded to introduce a mechanism to stabilise the electricity price for RO generation, nor to provide any further compensation for increased price variability than that already included in ROC bands.

D.75 The Banding Review setting ROC bands for 2013-17 (2014-17 for offshore wind) will take into account the impacts of the package when setting banding levels.

Grandfathering arrangements

D.76 Grandfathering is the policy intention to maintain a fixed level of RO support for the full lifetime of a generating station's eligibility for the RO, from the point of accreditation. Following consultation on banding and grandfathering in 2008, grandfathering was introduced for most technologies except those with a fuel cost or income. This was because we recognised the need for flexibility to amend support levels should fuel prices change.

D.77 In 2010, bio-energy developers suggested that plant was not being built as lenders and equity providers were withholding investment due to a lack of grandfathering. Therefore, after reviewing the policy we decided to extend grandfathering to dedicated biomass, anaerobic digestion, advanced conversion technologies such as gasification and pyrolysis, and energy from waste plant.

D.78 However, bioliquids and co-firing, along with the Combined Heat and Power (CHP) uplift and energy crops uplift remain not grandfathered. Consideration on whether to grandfather these technologies and uplifts will be taken as part of the current Banding Review, which is due to publish a consultation in summer 2011.

Preferred option for grandfathering arrangements

D.79 Our preferred option is for support for any technology that is not covered by our grandfathering policy on 31 March 2017, to be grandfathered at the RO support level applicable on that date. We are still considering whether any uplifts not covered by our grandfathering policy as at 31 March 2017 should be grandfathered in a similar way.

D.80 This was not an explicit option in the consultation document, however a number of industry representatives suggested grandfathering all technologies was the best way forward.

D.81 Grandfathering all technologies in the vintaged RO will provide industry greater revenue certainty, and reduce the costly administration burden of ongoing banding reviews for a limited set of technologies. Moreover, this will bring the RO in line with the treatment of renewables supported under the new FiT CfD mechanism, ensuring all renewable electricity will have long term fixed support.

Additional capacity greater than 5 MW added after 2017

D.82 Currently, stations in the RO can add capacity and receive 20 years of support on that additional capacity (up to 2037). The additional capacity would be awarded the ROC rate applicable to that technology at the time at which the additional capacity forms part of the generating station.

D.83 It is therefore necessary to address how additional capacity will be supported in the context of the RO closing to new capacity from 1 April 2017.

D.84 Outlined below is the preferred way forward for additional capacity that is greater than 5 MW. Separate provisions for additional capacity of less than 5 MW are detailed below.

Preferred option for additional capacity

D.85 In line with the closure of the RO to new accreditations, additional capacity will not be able to accredit under the RO after 31 March 2017.

D.86 However, we do want to continue to provide support to stations that add new capacity after 31 March 2017 and will do so through the FiT CfD mechanism. Generators who add additional capacity that is greater than 5 MW will be eligible to participate in the FiT CfD on the same terms as all other eligible technologies. The original capacity will continue to be supported under the RO.

D.87 Due to the end date of the RO in 2037, if additional capacity were able to continue to accredit under the RO after 2017, it would not be able to access a full 20 years of support.

D.88 In addition, given that we do not intend to carry out further RO banding reviews, providing support for additional capacity through the FiT CfD will allow the support to better reflect the appropriate level needed, at the time at which the additional capacity is installed and therefore ensure value for money for the consumer.

D.89 The administration of a FiT CfD will require approved and registered operational metering. We anticipate that output readings can be calculated on a pro-rata basis for stations that are also accredited under the RO.

Additional capacity less than 5 MW after 2017

D.90 Under current regulations, plants that are less than 5 MW and meet the relevant eligibility criteria, are able to choose between the RO and the existing small-scale FiT.

Preferred option for additional capacity less than 5 MW

D.91 We are committed to supporting small-scale and community generation.

D.92 We are minded that plants which are eligible for the current small-scale FiT will not be eligible for a FiT CfD. We are also minded that any renewable electricity developments which are ineligible for the current small-scale FiT will be eligible to access the FiT CfD on the same terms as all other eligible technologies. This would include investors wishing to deploy a technology at less than 5 MW capacity, not currently eligible for the small-scale FiT (e.g. wave, tidal, biomass, Advanced Conversion Technologies).

D.93 Any further amendments to the eligibility criteria for the current small-scale FiT would be considered through a separate consultation process relating to that scheme.

D.94 In Northern Ireland there is no small-scale FiT and all renewable electricity generation is supported under the NIRO. Incentivising small-scale generation is being considered as part of the Northern Ireland Executive's ongoing work on the suitability of a FiT CfD for Northern Ireland.

D.95 The administration of a FiT CfD will require approved and registered metering. We anticipate that output readings can be calculated on a pro-rata basis for stations that are also accredited under the RO.

Small-scale Feed-in Tariff schemes exceeding 5 MW

D.96 Small and micro generators participating in the existing small-scale FiT scheme will cease to be eligible for support through the FiT scheme if they add so much additional capacity that the total installed capacity of their installation exceeds 5 MW, as this is the maximum level permitted under the FiT scheme.

D.97 Currently, legislation allows generators to transfer to the RO if they exceed this maximum level. We need to address how such projects will be supported in the future.

Preferred option for small-scale Feed-in Tariff

D.98 We want to carry on supporting stations that cease to be eligible for the small-scale FiT, in the context of the introduction of the FiT CfD mechanism.

D.99 In line with the approach we are taking for new generation, between the introduction of the FiT CfD mechanism and 31 March 2017, we will offer generators that exceed the small-scale FiT maximum level a one-off choice between receiving support under the RO or participating in the FiT CfD mechanism.

D.100 From 1 April 2017, the RO will be closed to new generation. Therefore after this date any station that exceeds the maximum level permitted under the small-scale FiT scheme will not be able to receive support under the RO. They will be eligible to participate in the new FiT CfD mechanism on the same terms as all other eligible technologies.

Interaction with the Non-Fossil Fuel Obligation

D.101 Currently, projects operating under the Non-Fossil Fuel Obligation (NFFO) scheme are, where eligible, able to accredit under the RO, with the generator receiving the ROC benefit once their NFFO contract expires. It is therefore necessary to address how projects under the NFFO scheme will be treated going forward.

Preferred option for interaction with Non-Fossil Fuel Obligation

D.102 Sites which have already been developed in line with the terms of their NFFO contract and accredited under the RO will continue to receive support under the RO mechanism. This is consistent with our approach to other existing investments receiving support under the RO.

D.103 As currently, during the lifetime of the NFFO contract, ROCs will be awarded to the Non-Fossil Purchasing Agency (NFPA) or NFPA-nominated supplier. Once the NFFO contract expires, ROCs will continue to revert directly to the generator.

D.104 A number of those responding to the consultation asked for clarification on how we will treat generation that is yet to be developed under the remaining NFFO Orders.

D.105 In the case of generation developed between the introduction of the FiT CfD and 31 March 2017, projects developed under the NFFO will be required to accredit under whichever scheme (either the RO or the FiT CfD) provides the best return for the NFPA.

D.106 Regarding generation developed after the RO has closed to new generation (i.e. on or after 1 April 2017), projects developed under the NFFO will be eligible to participate in the CfD on the same terms as all other eligible technologies.

D.107 We intend that projects sterilised[6] from the RO (i.e. in the case of a generator breaching their NFFO contract) will similarly be sterilised from signing a CfD contract.

D.108 Similarly, in situations where the NFFO contract has been terminated, we intend to mirror how such projects are treated under the RO in the FiT CfD mechanism.

D.109 Finally, generation built on a site after the relevant NFFO Order has expired will be treated in line with the provisions we have set out for other new generation.

6 Where there exists an underdeveloped Non-Fossil Fuel Obligation (NFFO) contract relating to a specific site, that cannot then be developed outside of the terms of the NFFO contract in order to claim Renewables Obligation Certificates.