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Electricity Market Reform – Consultation Document

TSO

DEPARTMENT OF ENERGY & CLIMATE CHANGE

Electricity Market Reform

Consultation Document

December 2010

Electricity Market Reform

Consultation Document

Presented to Parliament by the Secretary of State for Energy and Climate Change
by Command of Her Majesty

December 2010

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How to respond

Your response will most useful if it is framed in direct response to the questions posed, though further comments and evidence are also welcome.

This consultation will run until 10th March 2011. Responses should be submitted to EMR-condoc@decc.gsi.gov. Responses will be considered alongside responses to HM Treasury's consultation on Carbon Price Support in preparation for reporting in Budget 2011, as well as the White Paper.

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We will summarise all responses and place this summary on our website at www.decc.gov.uk/en/content/cms/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

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Electricity Market Reform

Executive Summary

The challenge

Our electricity market has served us well, providing affordable and secure energy since the 1990s. The watchword has been the encouragement of competition overseen by Ofgem as the independent regulator of the sector. As a result we have had some of the lowest electricity prices in the EU and this model formed the basis for EU rules on energy markets and independent regulation. However, in the coming decades we face major new challenges which require careful but far-reaching reforms to meet our objective of ensuring the supply of reliable, low-carbon and affordable electricity:

- even as we improve energy efficiency, demand for electricity may need to double by 2050 – as decarbonisation of the economy means that electricity provides more of our heating and transport needs;

- to ensure security of supply, we will need to replace a quarter of our existing capacity by 2020, which are ageing and unlikely to meet environmental regulations. In the current system, maintaining the level of security of supply is left to market forces;

- the power sector needs to lead the decarbonisation of our economy, but the current market has a bias towards fossil fuels. DECC's 2050 analysis shows that the power sector emissions need to be largely decarbonised during the 2030s.The Committee on Climate Change has recently proposed that the power sector should be close to zero-carbon by 2030;

- around 30% of our electricity in 2020 needs to come from renewable sources (largely onshore and offshore wind), up from 7% today, to meet our legally binding EU target for renewable energy. The Government has asked the Committee on Climate Change to provide further advice in Spring 2011 about the longer-term potential for renewable energy;

- Under the current market, gas-fired generation is currently the lowest cost and lowest risk investment. It will continue to play an important role in the electricity sector – providing vital flexibility to support an increasing amount of low-carbon generation and to maintain security of supply.

However, current arrangements need to be reformed to allow equal access to the electricity market for a wider range of technologies, such as:

- Low-carbon generation technologies – renewable electricity (for example wind and tidal technologies), nuclear power and new fossil fuel power stations equipped with carbon capture and storage (CCS) technology; and

- Technology to reduce or manage electricity demand – by decreasing the amount of power we need through efficiency measures and increasing demand side response to more flexibly change our demand to match peak wind generation. In particular, the scope for demand side flexibility will significantly increase as electric vehicles become more common and the smart grid is established.

Overall, this means that we have a huge investment challenge. Ofgem have estimated that we need around £200bn in generation, electricity networks and gas infrastructure. Of this at least £110bn would be needed in new generation and transmission assets in electricity – over double the rate of the last decade. In a world of global competition for capital, this means increased investment by existing market participants and, in addition, seeking investment from new sources of capital.

Without reform, the existing market will not deliver the scale of long-term investment, at the pace we need, in particular in renewables, new nuclear and CCS, nor will it give consumers the best deal. However, if we are to meet our long-term carbon targets, we need to reform the market now, to make low-carbon investment more attractive.

Reform proposals

The Government is consulting on a package of options for reforming the electricity market. The proposals are designed to strike a balance between the best possible deal for consumers and giving existing players and new entrants in the energy sector the certainty they need to raise investment. Specifically, they are designed to ensure that low-carbon technologies become a more attractive choice for investors, and adequately reward back up capacity to ensure the lights stay on.

Our proposals are fourfold and deliver directly on commitments made in the Coalition Agreement:

- **Carbon price support**: Greater long-term certainty around the additional cost of running polluting plant. Supporting the carbon price will encourage investment in low-carbon technologies. By strengthening the carbon price for electricity generators, it will increase the cost of fossil fuel generation, , making lower-carbon power more attractive;

- **Feed-in tariffs**: Long-term contracts would provide more certainty on the revenues for low-carbon generation and make clean energy investment more attractive still. A ‘contract for difference’ model for low-carbon generation is proposed, as this should control costs for consumers, provide stable returns for investors, and maintain the market incentives to generate when electricity demand is high. However, there are design and implementation issues which need further consideration and which Government is keen to address through this consultation. In light of these design and implementation issues, the Government feels it is necessary to consider and consult on an alternative model and considers a premium feed-in tariff as a credible alternative that could enable the electricity sector to meet the Government's decarbonisation and security of supply objectives

- **Capacity payments**: targeted payments to encourage security of supply through the construction of flexible reserve plants or demand reduction measures (so-called negawatts) to ensure the lights stay on. Capacity payments will ensure there remains an adequate safety cushion of capacity as the amount of intermittent and inflexible low-carbon generation increases; and

- **Emissions Performance Standard**: A back-stop to limit how much carbon the most carbon intensive power stations - coal - can emit. An emissions performance standard will reinforce the existing requirement that no new coal is built without demonstrating carbon capture and storage technology.

Ofgem's review into the liquidity of the electricity wholesale market is an essential complement to these reforms, to safeguard the competitiveness of the market, and the ability for new firms to enter and compete alongside incumbents. The Government believes current levels of liquidity are likely to be inadequate and are impeding the efficient operation of the market. Competition in retail energy markets is an important means of securing consumer interests. It is vital that retail energy markets work to keep energy prices as low as possible, consistent with the need for investment to meet climate change and energy security objectives. Ofgem's review of retail energy markets, which will consider whether further changes are needed to ensure the market works in the interests of consumers and to increase transparency, will be crucial to achieving this.

The impact of these reforms on household bills to 2020 will be broadly in line with existing plans as set out in the Annual Energy Statement[1]. In the longer run to 2030, while no targets or trajectories have been set for this period yet, the Government believes the lead package of reforms would deliver an effective pathway to 2050, security of supply and consumer bills that are lower than continuing with existing policies. With an illustrative decarbonisation benchmark of 100gCO2/kWh in 2030[2], the lead package of reforms would result in a period of higher investment in the 2020s and household bills would then be 4% (around £29/year) lower in the five year period up to 2030 than continuing with existing policies despite delivering a higher level of ambition. The actual level of impact depends on the rate of decarbonisation among other things and since this has not yet been set it is not possible to be more definite at this stage. The key conclusion the Government draws from the modelling is the trend in bill impacts: small impacts on bills in the near term, but in the longer-term bills are expected to fall by 2030,

[1] DECC Annual Energy Statement and Estimated impacts of energy and climate change policies on energy prices and bills, July 2010

[2] Electricity Market Reform, Analysis of policy options, Redpoint (Dec 2010)

despite delivering more low-carbon investment. The individual bill numbers in any given year are less insightful because they will be affected by other issues in the sector, such as the capacity margin in that particular year which will also affect wholesale prices

The impact of the reform package on business bills to 2020 will also be broadly in line with existing plans as set out in the Annual Energy Statement, though the reform package may have a small impact on bills up to 2020 (2% higher). While no decarbonisation trajectory has been set the impact in the longer term to 2030 might, on the basis of the modelled benchmark of 100g/kWh lead to somewhat higher bills in the short term as more investment flows through into low carbon, and then bills that are 5% lower (£77,000) in the 5 year period to 2030 than continuing current policies (despite delivering a higher level of ambition). Impacts on different sizes and different kinds of businesses will of course be different than this average. Further analysis of the impact of this reform package on businesses will be undertaken for the White Paper.

The Government will publish a White Paper in late Spring 2011, incorporating a response to this consultation, and setting out detailed legislative and administrative proposals to support these reforms. The conclusions of the Ofgem Review will be published alongside, and should support implementation of market reforms by providing greater clarity for investors on the respective roles of Government and the regulator. Legislation will follow as soon as possible thereafter and the transition to the reformed market will follow before the end of the Parliament.

In the transition to the new measures, Government will seek to minimise uncertainty and delays to planned investments by establishing appropriate ‘grandfathering’ arrangements.. Feed-in-tariffs could be generally introduced from 2013 once legislation has been passed, but accreditation under the RO could also continue until 2017 to minimise the risk of disruption for developers. More details regarding the transition and implementation arrangements for these policies are set out in the annex to this document and the Government will set out the approach it will take, in full, in the White paper.

Energy policy is generally a reserved matter. However, certain powers have been executively devolved to Scotland, and the generation of electricity in Northern Ireland is fully devolved. We recognise that the proposals contained in this document have not been arrived at through full consultation with Scotland and Northern Ireland and that any potential implications for devolved energy policy have still to be determined. Therefore the UK Government will work closely with our devolved counterparts to establish how these reforms might apply across the United Kingdom.

This consultation will run until 10th March 2011. Responses should be submitted to EMR-condoc@decc.gsi.gov.uk and will be published unless respondents request confidentiality. Responses will be considered alongside responses to HM

Treasury's consultation on Carbon Price Support[3] in preparation for reporting in Budget 2011, as well as the White Paper.

[3] http://www.hm-treasury.gov.uk/consult_index.htm

CONSULTATION QUESTIONS

The Government's objective for the consultation process is to develop the evidence base on the options for reforming the electricity market. Therefore, respondents to this consultation are asked to provide evidence and supporting information to back-up any opinions expressed in their response.

Current Market Arrangements

1. Do you agree with the Government's assessment of the ability of the current market to support the investment in low-carbon generation needed to meet environmental targets?

2. Do you agree with the Government's assessment of the future risks to the UK's security of electricity supplies?

Options for Decarbonisation

Carbon Price Support

This is the subject of a separate HM Treasury / HMRC consultation. Readers of this consultation with specific comments on the carbon price support mechanism should cover these in a separate submission to the HM Treasury / HMRC consultation, which can be found at http://www.hm-treasury.gov.uk/consult_index.htm

Feed-in Tariffs

3. Do you agree with the Government's assessment of the pros and cons of each of the models of feed-in tariff (FIT)?

4. Do you agree with the Government's preferred policy of introducing a contract for difference based feed-in tariff (FIT with CfD)?

5. What do you see as the advantages and disadvantages of transferring different risks from the generator or the supplier to the Government? In particular, what are the implications of removing the (long-term) electricity price risk from generators under the CfD model?

6. What are the efficient operational decisions that the price signal incentivises? How important are these for the market to function properly? How would they be affected by the proposed policy?

7. Do you agree with the Government's assessment of the impact of the different models of FITs on the cost of capital for low-carbon generators?

8. What impact do you think the different models of FITs will have on the availability of finance for low-carbon electricity generation investments from both new investors and existing the investor base?

9. What impact do you think the different models of FITs will have on different types of generators (e.g. vertically integrated utilities, existing independent gas, wind or biomass generators and new entrant generators)? How would the different models impact on contract negotiations/relationships with electricity suppliers?

10. How important do you think greater liquidity in the wholesale market is to the effective operation of the FIT with CfD model? What reference price or index should be used?

11. Should the FIT be paid on availability or output?

Emissions Performance Standards

12. Do you agree with the Government's assessment of the impact of an emission performance standard on the decarbonisation of the electricity sector and on security of supply risk?

13. Which option do you consider most appropriate for the level of the EPS? What considerations should the Government take into account in designing derogations for projects forming part of the UK or EU demonstration programme?

14. Do you agree that the EPS should be aimed at new plant, and 'grandfathered' at the point of consent? How should the Government determine the economic life of a power station for the purposes of grandfathering?

15. Do you agree that the EPS should be extended to cover existing plant in the event they undergo significant life extensions or upgrades? How could the Government implement such an approach in practice?

16. Do you agree with the proposed review of the EPS, incorporated into the progress reports required under the Energy Act 2010?

17. How should biomass be treated for the purposes of meeting the EPS? What additional considerations should the Government take into account?

18. Do you agree the principle of exceptions to the EPS in the event of long-term or short-term energy shortfalls?

Options for Market Efficiency and Security of Supply

19. Do you agree with our assessment of the pros and cons of introducing a capacity mechanism?

20. Do you agree with the Government's preferred policy of introducing a capacity mechanism in addition to the improvements to the current market?

21. What do you think the impacts of introducing a targeted capacity mechanism will be on prices in the wholesale electricity market?

22. Do you agree with Government's preference for a the design of a capacity mechanism:

- a central body holding the responsibility;
- volume based, not price based; and
- a targeted mechanism, rather than market-wide.

23. What do you think the impact of introducing a capacity mechanism would be on incentives to invest in demand-side response, storage, interconnection and energy efficiency? Will the preferred package of options allow these technologies to play more of a role?

24. Which of the two models of targeted capacity mechanism would you prefer to see implemented:

- Last-resort dispatch; or
- Economic dispatch.

25. Do you think there should be a locational element to capacity pricing?

Analysis of Packages

26. Do you agree with the Government's preferred package of options (carbon price support, feed-in tariff (CfD or premium), emission performance standard, peak capacity tender)? Why?

27. What are your views on the alternative package that Government has described?

28. Will the proposed package of options have wider impacts on the electricity system that have not been identified in this document, for example on electricity networks?

29. How do you see the different elements of the preferred package interacting? Are these interactions different for other packages?

Implementation Issues

30. What do you think are the main implementation risks for the Government's preferred package? Are these risks different for the other packages being considered?

31. Do you have views on the role that auctions or tenders can play in setting the price for a feed-in tariff, compared to administratively determined support levels?

- Can auctions or tenders deliver competitive market prices that appropriately reflect the risks and uncertainties of new or emerging technologies?

- Should auctions, tenders or the administrative approach to setting levels be technology neutral or technology specific?

- How should the different costs of each technology be reflected? Should there be a single contract for difference on the electricity price for all low-carbon and a series of technology different premiums on top?

- Are there other models government should consider?

- Should prices be set for individual projects or for technologies

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

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

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

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

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

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

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

- All new renewable electricity capacity accrediting before 1 April 2017 accredits under the RO;

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

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

- Carry out scheduled banding reviews (either separately or as part of the tariff setting for the new scheme)? How frequently should these be carried out?
- Carry out an "early review" if evidence is provided of significant change in costs or other criteria as in legislation?
- Should we move them out of the "vintaged" RO and into the new scheme, removing the potential need for scheduled banding reviews under the RO?

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

- Continue using both target and headroom
- Use Calculation B (Headroom) only from 2017
- Fix the price of a ROC for existing and new generation

Chapter 1: Objectives

Chapter Summary:

The Government's objectives are Security of Supply, Decarbonisation and Affordability. Alongside this we will use four broad principles of cost effectiveness, durability and flexibility, practicality and coherence to judge the effectiveness of different market design options.

Reform of our electricity market is needed for us to achieve our requirement to reduce greenhouse gas emissions by at least 80% by 2050. A new policy framework is essential to help us change the way we use energy, deliver the investment required to build a low carbon power system that provides security of supply at a price affordable for consumers. This framework will continue to be market based, providing sufficient incentives to attract private investment in new generation, while also encouraging increased competition through widening market participation.

Our 2050 pathways analysis demonstrated that it is possible to meet our 2050 emissions reduction target. But decisions we take now will be key to outcomes over the next 40 years. To ensure security of supply later in this decade and the 2020s, market design will need to provide the right signals to ensure sufficient investment in new base load, as well as flexible plant and other technologies such as interconnection, storage and demand side response to balance the system. Decarbonisation of the whole economy can be achieved most effectively if the electricity industry is largely decarbonised by the 2030s so that electrification of heat and transport can follow. To achieve this affordably markets should be allowed to function efficiently. Government should remove barriers to entry, intervening only to resolve identified market failures where necessary

1. Transforming our electricity system is crucial to meeting our security of supply and climate change goals. Our electricity system has served us well up to now, but new objectives and challenges over the next few decades mean that reforming our electricity market is essential to deliver the investment we need in new plant, and in particular low-carbon generation. A new policy framework for the electricity market can ensure that this transformation is achieved while minimising the costs to consumers and businesses and at the same time ensuring a secure electricity supply.

2. A modern electricity system for the UK would continue to harness the power of the market and private investment to minimise costs and promote competition while ensuring that our goals on climate change and secure electricity supplies are achieved. Smart meters and a smarter grid will enable suppliers to give consumers clearer information and new tariff options that may improve consumers' ability to decide how much electricity they use and at what times. Local communities should be empowered to improve energy efficiency as well

as to generate low-carbon and renewable electricity and stronger incentives should lead to innovation in the way the UK makes use of demand side response in modifying peaks in electricity demand. Across the UK our fleet of power plants needs to be gradually transformed into, or replaced by. a predominantly low-carbon based supply. We need to do this in a way that gives enough certainty to investors, and potential new investors, about our policy direction, that supports the growth of green industries and maintains our security of supply by ensuring we have a diverse range of generating technologies and fuel sources.

3. The UK Climate Change Act (2008) sets out a requirement to reduce our greenhouse gas emissions by at least 80% by 2050 relative to 1990 levels.

4. The UK will need to achieve these emissions reductions while at the same time safeguarding energy security, by replacing plant that is already scheduled to close and by ensuring that the system is sufficiently flexible to balance supply and demand and avoid outages. The transformation of the electricity system will require large scale investment and Government is also keen to maximise the economic opportunities for UK business presented by national and global decarbonisation.

5. In July the Government published its 2050 Pathways Analysis. This work set out a framework through which to consider the choices and trade-offs which the Government will have to make over the next forty years in achieving our decarbonisation goals. The Pathways Analysis showed that it is possible for us to meet the 80% emissions reduction target in a range of ways, and the Government produced the 2050 Calculator tool through which people can explore the options. Whilst that work did not attempt to choose a single pathway, it did point to some conclusions about actions which appeared to be common to many of the plausible pathways to meeting our targets.

6. Key among these conclusions was the need to change the way we use energy and the need to transform our energy supply. The analysis indicated the importance of electrifying a substantial proportion of the energy demand of our heating, transport and industry. The impact of this transition would be that, even as we keep overall demand for energy stable or reduce it, the UK's demand for electricity would be expected to increase, and potentially as much as double by 2050. To obtain the benefits of this transition, we would also need to decarbonise our electricity supply. The Pathways Analysis indicated that electricity generation would need to be largely decarbonised during the 2030s.

7. Taking a longer term view introduces uncertainties about the technologies that might facilitate decarbonisation, the amount of energy we will need to produce, the costs and benefits of taking any particular action and the availability of resources both here and abroad. But a successful low-carbon transition requires investors and consumers to have confidence to act, and an understanding of the timelines needed to deliver large building and infrastructure projects. Decisions made in the next decade will have consequences for the next 40 years. Choices must therefore be based on an

understanding of the long-term challenges that the UK faces in decarbonising in a sustainable way and maintaining energy security.

8. In order to achieve this vision the Government has three objectives for the UK electricity system:

- **Security of supply**: Maintaining security means providing secure reliable supplies to homes and businesses by ensuring that there is sufficient generating capacity, diverse technologies, fuels and fuel sources and a resilient transmission system. Over 19GW of nuclear, oil, coal and gas plant is scheduled to close over the coming decade as stations reach the end of their design lives and due to the effects of environmental legislation. Over 20 GW of new capacity is either in construction or development and will therefore enable the UK to maintain secure supplies for the time being. However modelling shows that de-rated[4] capacity margins will reduce in the latter part of the decade from circa 20% to below 10% and we need to ensure that the market design provides the right investment signals for both new baseload gas plant and the additional flexible plant that is required to ensure system balancing in the latter part of this decade and into the 2020s.[5]

  Security of supply can also be enhanced through diversifying the technologies we use in the supply of electricity. Government is keen for interconnection, storage and demand side response to play their part in supporting the transition to a low-carbon generating mix as intermittency increases.

- **Decarbonisation:** The 2050 emissions reduction commitment requires at least an 80% reduction in emissions across the whole economy. This can be achieved most cost effectively if the electricity system makes early progress in decarbonising. This allows transport and heat to be electrified and decarbonised in parallel. Our primary objective for the reforms we are making to the electricity system are to ensure the sector is largely decarbonised during the 2030s.

  A supporting objective is to ensure that the target for 15% renewable energy consumption across the UK economy is achieved by 2020. This is likely to mean circa 30% renewable penetration in the electricity market as this is one of the lower cost and most mature areas for renewable energy deployment.

- **Affordability**: The market design should deliver its objectives efficiently to minimise cost increases for consumers. Where markets can function effectively they should be allowed to do so, Government should take action to reduce barriers to entry to enhance competition and where there is market

[4] The de-rated capacity margin is the capacity margin adjusted to take account of availability of plant, specific to each type of generation technology. It reflects the probable 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).
[5] http://www.decc.gov.uk/en/content/cms/ consultations/ emr/emr.aspx aspx

failure Government's interventions should be well designed and targeted and in line with the Principles for Regulation[6].

9. Overall, meeting these objectives requires significant new investment. Over £110bn needs to be spent on new generation, transmission and distribution assets in this decade. This is over double the rate of investment of the last decade.

10. Alongside their ability to meet our objectives, we will judge the effectiveness of market design reform options against 4 broad principles.

- **Cost-effectiveness:** the policy response must be cost-effective, preserving where appropriate, the competitive pressure on firms to make efficient decisions regarding the siting, operation and maintenance of their plant. As well as being effective relative to their cost it is important that interventions are affordable in absolute terms to electricity consumers and taxpayers.

- **Durability and Flexibility**: the policies must achieve an appropriate balance between the Government's objectives in a wide range of scenarios and should be robust to a number of unlikely outcomes regarding carbon prices, fossil fuel prices, and technology costs.

- **Practicality**: the policies must be able to work in reality as well as in theory, and there must be a manageable transition between the present system and the new market framework.

- **Coherence**: the individual policies must combine together in a complementary manner rather than work against each other.

11. There are a range of factors that contribute to our assessment of how market mechanisms perform against these 4 broad principles. These are discussed in our assessment of market reform options. The Government is also committed to ensuring that the transformation of the UK's energy sector will be achieved in a sustainable way by balancing environmental, social and economic considerations. In addition, we have considered the public finance impacts of the different.

12. The attractiveness of the UK electricity market is affected by other areas of policy including the planning system, technology licensing and grid connection regime that all support the development of major infrastructure. The Electricity Market Reform project is not trying to address these wider factors, but we recognise that they are critical enablers for investment decisions that have the potential to significantly reduce investment costs and are being considered in e.g. the National Policy Statements, the recent consultation on offshore grids and other recent publications by the delivery offices (ORED, OND and OCCS).

[6] www.bis.gov.uk/reducing-regulation

Chapter 2: Current Market Arrangements

Chapter Summary:

Since liberalisation in 1990 the current market structure has delivered the necessary levels of investment to enable adequate capacity margins and competitive electricity prices whilst ensuring that we make important steps towards decarbonisation through our commitments on Kyoto emissions targets.

Over the course of the next decade the UK's electricity generation sector will need to dramatically reduce its carbon intensity in order to achieve our 2050 carbon reduction goals. Without additional intervention the current market arrangements are unlikely to ensure that we can meet these goals.

The UK's electricity supplies are amongst the most reliable in Europe. While the current market provides incentives to encourage generators and suppliers to align electricity production with demand at all times, these incentives may not be strong enough to overcome the additional uncertainty that arises as we deploy intermittent renewables and decarbonise. As such, while investment in new flexible generating capacity would be brought forward without any Government intervention, the overall level may not be sufficient to ensure adequate levels of security of supply.

1. This Chapter provides a high level summary of the current design of the GB electricity market, assesses the effectiveness with which it has delivered against Government's objectives until now and provides an assessment of why the Government believes that market reform is needed.

How the Market has developed

2. The current market has developed following liberalisation in the 1990s. The intention was to create a competitive electricity system where prices are determined without administrative price caps or other regulatory interventions and where those real-time unfettered movements in price, and the freedom of market participants' actions (including contracting and hedging), would be the main drivers of investment behaviour. This is similar in many ways to a range of other commodity markets.

3. The UK market is divided into:

- the wholesale market where generators, suppliers and large customers buy and sell electricity;

- transmission and distribution networks at national and regional levels; and
- the retail market, where energy suppliers sell to domestic and business customers.

4. The electricity wholesale market is designed to be much like a typical commodity market. Generators (those who produce electricity) sell electricity to suppliers (those who sell electricity to consumers) through bilateral contracts, over the counter trades and spot markets.

5. However, electricity cannot be easily stored, so to ensure a secure supply of electricity the amount being produced (supply) and the amount being consumed (demand) must match at all times; the system must 'balance'.

6. Electricity is traded in 30-minute blocks. This continues until an hour before the start of a block (a point called gate closure). At this point the volume of electricity generators have contracted to produce and that suppliers have contracted to consume should be equal (balance). They are incentivised to do this by having to pay an imbalance penalty (cash out price) if they have not contracted sufficiently to cover the amount they actually generate or supply to consumers.

7. After gate closure the responsibility for ensuring supply equals demand on a second-by-second basis is held by a central body (National Grid, the System Operator), as it is not technically possible to do this through bilateral trading.

8. Competition between generators is intended to incentivise improvements in operational efficiency and to encourage investment in technologies that are relatively low cost and low risk. Generators currently assess a number of variables when they take investment decisions. These factors include: technology choice; development and construction risk; investment timing decisions; operating risk; fuel price risk; carbon price risk; electricity price risk; and regulatory risk.

9. In the retail market, competition between suppliers was also introduced to improve quality of service to consumers, encourage consumer switching and to create pressure for lower and more innovative tariffs.

10. Strong independent regulation through Ofgem has been a key feature of the design and is important as it provides stability for investors and protects consumers from market abuse by monopoly transmission and distribution companies and from any anti-competitive practices by generators and suppliers. Government will need Ofgem to continue to play this essential role within the reformed electricity market and is carrying out a review of Ofgem to ensure that it remains an effective, independent economic regulator.

11. This market structure has been effective. The liberal GB electricity market has delivered increased choice in tariffs and services and enabled consumers to switch suppliers. In addition, electricity supplies are among the most reliable in

Europe[7]. However, the basic market design has been repeatedly modified, through domestic and EU actions, since privatisation. As climate change has become more clearly understood and emerged as a priority for Government, incentives and regulations that are designed to drive the delivery of renewables and decarbonisation, have been added to the policy framework. These incentives and regulations include:

- EU Emissions Trading System (EU ETS) – introduced in 2005, it creates a Europe wide price on carbon that drives decarbonisation across a range of sectors (including the power sector).

- Renewables Obligation (RO) – introduced in 2002, and revised on a number of occasions since then, adds a specific requirement for suppliers to source increasing proportions of electricity from renewable generation or pay a buyout price, the proceeds of which are recycled to suppliers in proportion to the renewable electricity they supplied.

- the Climate Change Levy (CCL) - introduced in 2001 as part of the UK's commitment under the Kyoto Protocol to reduce emissions. By taxing non-domestic energy use, the CCL aims to promote energy efficiency and reduce greenhouse gas emissions. Businesses that have Climate Change Agreements with the Government get an 80% reduction on the levy (to be reduced to 65% in April 2011). Renewable electricity and electricity produced from some CHP plants are exempt from CCL;

- continued public sector investment in carbon capture and storage (CCS) technology for four power stations, including up to £1bn in this spending review period for the construction of the first of these demonstration projects;

- feed-in tariffs for small scale generation – introduced in April 2010 this scheme encourages the deployment of smaller renewable installations below 5MW, particularly by organisations, businesses, communities and individuals not traditionally engaged in the electricity market. This scheme was introduced in recognition of the potential role communities could play in the UK's transition to a low-carbon economy. The Government is committed to encouraging community-owned renewable energy schemes where local people benefit from the power produced. The small scale feed-in tariffs are not affected by the reforms proposed in this consultation, which are aimed at large-scale low-carbon generation; and

- other measures to incentivise energy efficiency in the business and public sector include the Carbon Reduction Commitment Energy Efficiency Scheme, and will soon include the Green Deal for both the domestic and the non-domestic sectors.

[7] In 2008/9 the transmission reliability was approximately 99.99974%, measured in terms of index of unsupplied energy to energy actually delivered. DECC/Ofgem (2010) Statutory Security of Supply Report

12. The Government supports further integration of EU electricity markets as this will increase security of supply and facilitate the move to a low-carbon economy at least cost to consumers. It is important that our reform package is consistent with the market integration work at EU level and we will ensure that we take full account of this work as we develop our market mechanisms over the coming months.

What the Current Market has delivered

13. The market has performed well over the period since privatisation and liberalisation. The UK market has:

- delivered the almost 30GW of gas generation currently in operation[8] and maintained an adequate capacity margin (the margin of spare capacity in excess of maximum electricity demand). This has resulted in low risks of electricity demand not being met.

- resulted in electricity prices which have been comparatively low and fairly responsive to movements in fuel costs[9];

- supported the deployment of increasing amounts of renewables from 3.1GW in 2002 to 8GW in 2009; and

- reduced greenhouse gas emissions. The UK is one of only a few countries that will meet its Kyoto emissions targets. The UK also remains on track to meet its first three carbon budgets which set a broad trajectory for the decarbonisation of the UK economy to 2050.

Why market reform is required

14. As the UK progresses in decarbonising the electricity sector, the Government will need to ensure that electricity supplies continue to be secure.

15. Over the coming years the UK's electricity generating sector needs to dramatically reduce its carbon intensity. An opportunity for this transformation arises in the next decade when a large proportion of our existing coal and oil generation will close as a result of the new standards being introduced by the Large Combustion Plant Directive and Industrial Emissions Directive and as nuclear plants come to the end of their lives[10]. At the same time, the need to meet our legally binding EU renewable energy target will require a dramatic increase in the proportion of UK electricity that is generated by renewables.

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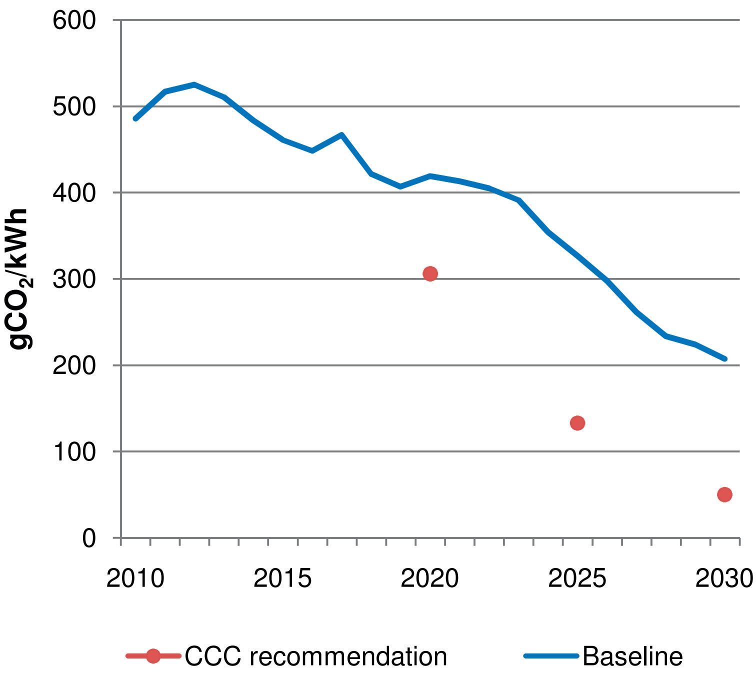
[8] DECC, Digest of UK Energy Statistics (2010)
[9] DECC analysis shows UK day-ahead wholesale electricity prices have generally followed day-ahead NBP gas prices.
[10] DECC/OFGEM (2010) "Statutory Security of Supply Report" http://www.decc.gov.uk/assets/decc/What%20we%20do/UK%20energy%20supply/resilience/803-security-of-supply-report.pdf

Approximately 30% of electricity will need to come from renewable sources by 2020, up from 6.6% in 2009.

16. The consequence of this combination of removing the most carbon intensive fossil fuel plants and replacing them with a combination of renewable generation and a mix of baseload and back-up flexible resource is that there will be a marked decline in the carbon intensity of the UK electricity generating sector. Figure 1, below, shows that under the current market arrangements (including the RO) and without any additional form of Government intervention we will achieve approximately 20% reduction in the carbon intensity of power generation to 2020, rising to approximately 60% by 2030, relative to 1990 levels. Nevertheless, without reform, carbon intensity will not fall fast enough to keep the UK on most plausible pathways to meet our 2050 emissions reduction target.

Figure 1: Carbon Intensity of UK Electricity Generation



17. Much of the low-carbon technology capacity that could be deployed during the course of this decade has high capital costs and is either only able to generate intermittently (e.g. when the wind blows) or is inflexible and therefore has to run continuously for either technical or economic reasons. These characteristics of low-carbon plant mean that the system will require flexible capacity that is able to respond to demand spikes or supply shortfalls from intermittent plant. While existing and new thermal plant will still be needed to provide reliable generation, the system will also need technologies such as demand side response, storage, interconnection and new thermal plant to fulfil this vital role, see Box 1 below. The ability to dispatch these flexible

resources[11] to offset intermittency and meet demand spikes will ensure that overall system resilience is maintained but will result in some plants operating for fewer hours overall each year than would be the case in a market that included a lower level of renewables and other inflexible low-carbon plant.

18. Without reform, spare capacity[12] will fall below a margin of 10% over the decade[13]. As margins fall there is an increasing risk of localised instances of supply not meeting demand, yielding ‘energy unserved’ which take the form of blackouts or voltage reductions.

19. Therefore the Government believes that although current market arrangements will continue to deliver our objectives in the short term, reforms are needed to deliver the investment that will ensure affordable and secure low-carbon electricity for the long term.

20. Achieving the UK’s decarbonisation and security of supply objectives will depend on investors moving away from the conventional model of using coal and gas investments to deliver the bulk of the UK’s electricity generation and instead rely increasingly on low-carbon technologies such as wind and nuclear. Three factors are of particular concern:

- **economics of low-carbon generation,** in particular the high capital costs and low operating cost of low-carbon generation are not well suited to the UK market where gas is the marginal plant; This is because gas is generally the price setting plant and can pass through any changes in gas or carbon prices to the electricity price. Therefore electricity and gas prices (and hence revenues and costs) tend to move together. By contrast low-carbon generators are price takers and are more exposed to gas or carbon price volatility.

- **investment signals to ensure security of supply. Clear signals to invest in flexible resource** (such as gas-fired generation and demand side response) that support security of supply are needed. However, in the current system they are unlikely to be strong enough to provide the absolute level of capacity required or the flexible capacity needed to support increasing levels of intermittent generation. Current high capacity margins are, in part, a reflection of slower than anticipated economic growth due to the recession; and

- **finance requirements of low-carbon generation –** to support the construction of £70-75bn of new plant in the next ten years will stretch and possibly exceed the balance sheet capacity of incumbent firms. Therefore we need to attract investment from new entrants, while encouraging the incumbent firms to maximise their pace of investment.

[11] The term resource is sometimes used to denote both supply and demand side contributions.
[12] A level of spare capacity is needed to mitigate against such risks as generation outages. forecasting errors and variations in weather. As discussed later in the chapter, a margin around 10% is generally considered to provide an appropriate balance between the costs of spare capacity and the security of supply benefits.
[13] See Figure 3 below.

21. These factors combine to make low-carbon investment slow to come forward and expensive to develop which results in increasing concerns around the **efficiency and fairness** of the current design and the costs that it passes through to consumers.

22. Each of these issues is now considered in greater detail in the sections below.

Box 1: System Flexibility

In addition to using conventional gas generation and biomass technologies to balance the increasingly intermittent and inflexible generating mix we are likely to have in future, there are a range of other technologies that could make important contributions because they add to diversity, increase competition and are low-carbon. The Government is keen to structure the market in a way that allows the private sector to choose from a range of technologies to be part of the mix, allowing each technology to play an appropriate part. This box sets out the emerging technologies which could play a role in balancing supply and demand.

Interconnection: Interconnectors are physical links between GB and other electricity grids that allow electricity to be imported or exported in response to appropriate price signals. The UK currently has 2.6GW of interconnection which is around 3% of peak GB demand. Different countries have differing peak demand times, so trade across interconnectors can bring security of supply without extra investment in plant. Interconnection can play a larger role in future, enabling cost effective integration of low-carbon energy by allowing for export/import at times of high/low renewable output, and allowing available capacity to support a broader system.

Demand Side Response: This involves shifting demand patterns in order to facilitate balancing of supply and demand. Response from consumers is usually triggered by a price signal. Historic high capacity margins have meant that use of demand side response (DSR) has been relatively limited in GB. The system operator contracts approximately 200 MW of interruptible industrial demand from large consumers (who stop energy intensive processes when instructed, in return for payment), as well as a limited amount of frequency control demand management. Apart from this, there are mechanisms such as the Economy 7 tariff which incentivise consumption, such as the charging of electric heaters, outside peak time[14]. The Government envisages an important role for DSR in the future as it has strong potential to assist system balancing and reduce costs and a more dynamic demand side can reduce the power of market players on the supply side.

Electricity storage: Like demand response, electricity storage currently plays a limited but important role in balancing the system. Electricity storage involves storing electrical energy in another form (such as heat or gravitational potential energy) when supply outstrips demand, and reproducing this as electricity when they system requires it. Currently, installed storage capacity in GB is just under 3GW and is largely made up of pumped storage, this being the only established technology at present. Storage has significant potential to grow as it can capture energy generated by inflexible low-carbon sources and reproduce this at times of need. It also offers significant technical flexibility and which can assist in the 'fine tuning' of the network which is carried out by the System Operator.

[14] An international example of DSR is from France, where EDF's Tempo tariff informed customers in advance of the electricity price for the next day using colour coded lights. Consumption was seen to shift on average by as much as 45% between the most expensive (red days) and the cheapest (blue days).

The characteristics and economics of low-carbon technologies

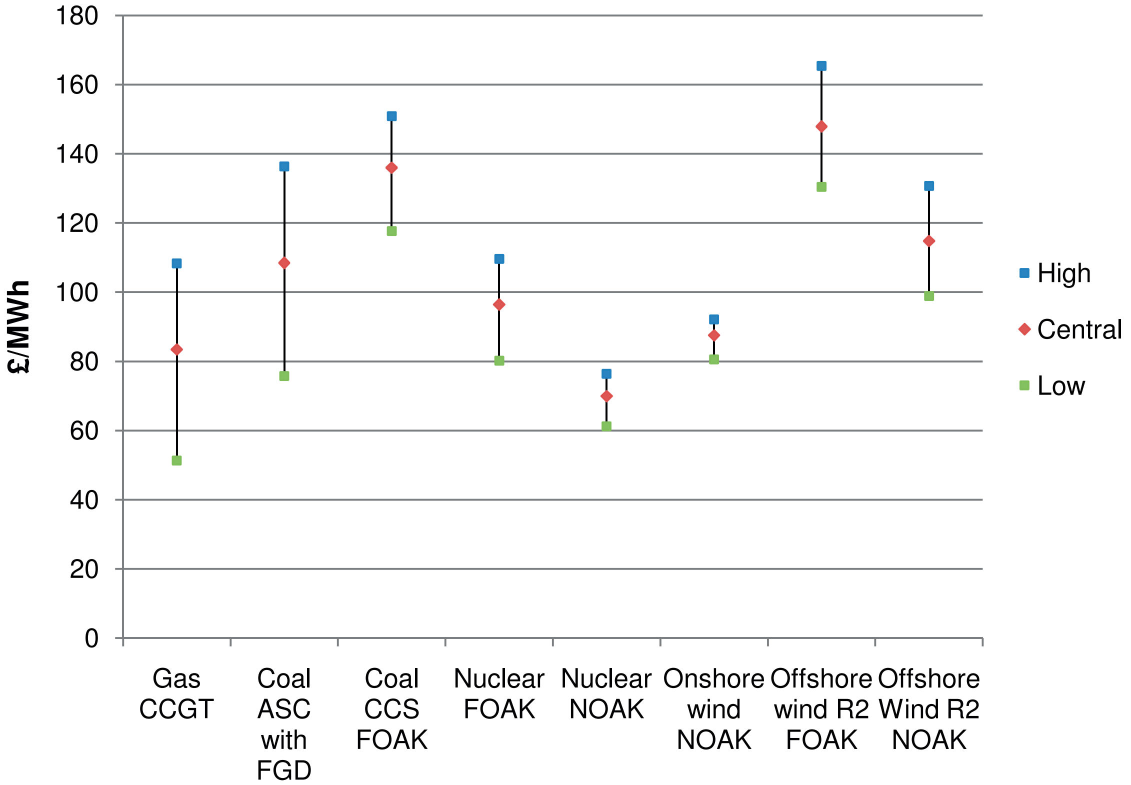
23. Gas-fired power stations are a mature technology with low and predictable capital expenditure. They are quick to build and fuel costs, which are a large proportion of operating costs, are naturally hedged because the price of electricity moves in line with the price of gas, since gas (or sometimes coal) is typically the price setting (marginal) plant. The generation costs will tend to fall in line with any fall in revenues as electricity prices fall, preserving profitability. Gas-fired power stations are able to run flexibly and can therefore relatively easily respond to shifting demand. The costs of flexing a gas plant to respond to daily peaks in demand are relatively modest although more frequent stop/start and fast ramp-up operations do have a significant impact on maintenance costs.

24. Each of the low-carbon technologies the Government is considering differs materially from this standard investment choice. In particular, low-carbon generation typically has high construction (capital) costs and low operating costs, and as such are wholesale price takers. It is therefore difficult to make an investment case for them in a market where wholesale electricity prices are predominantly set by the short run marginal costs of gas and coal plant, even if the carbon price was high enough for their levelised costs to be similar.

25. The levelised costs of generation are displayed in the graph at Figure 2 while the technical characteristics of each technology that affect investment appetite in ways that go beyond the cost of generation are summarised in Table 1 below. The figures below in Figure 3 cover the direct generation costs only and not the associated costs of upgrading and extending the transmission and distribution system. These associated costs could differ substantially between technologies and are likely to be highest for offshore technologies, for example the costs of connecting the Round two offshore windfarms to the onshore grid is estimated to be approximately £20bn[15].

[15] http://www.ofgem.gov.uk/Media/FactSheets/Documents1/offshoretransmissionfsupdate.pdf

Figure 2: Levelised costs of generation technologies



Notes: Estimated levelised costs, assumes 2010 project start, 10% discount rate for all technologies. Ranges reflect high, central and low scenarios for fossil fuel and carbon prices and construction costs. FOAK is first of kind technology and NOAK is Nth of Kind. Coal ASC with FGD refers to advanced super critical coal plants with flue gas desulphurisation. Coal CCS refers to coal plants with carbon capture and storage.

Source: DECC analysis based on Mott MacDonald 2010

26. Biomass generation and combined heat and power are further forms of low-carbon resource that the Government wishes to participate in the GB market. Currently both technologies require greater capital and operating investment than gas CCGT. In today's electricity market, neither is able to compete on price without financial support.

27. Such support, for onshore and offshore wind, biomass and renewable CHP is currently provided by the Renewables Obligation. The availability of capital and operating support for a 20 year period (subject to the 2037 end date for the RO) reduces the perceived financial risks associated with these newer technologies and hence allows them to participate in the UK electricity market. However even if the scheme's current 2037 end date were extended the Renewables Obligation would not be the most cost effective mechanism in incentivising post-2020 deployment. These issues are discussed further in Chapter 3.

Table 1: A qualitative assessment of the technical characteristics of each technology

	Capital Costs	Build Time	Technology Risk	Operational and Maintenance Risks	Generating costs linked to gas / coal price	Flexibility / ability to dispatch generation on demand
Gas (CCGT)	Low	Short	Low	Low	Closely aligned	Flexible
Onshore Wind	Medium	Short	Low	Low	Not Linked	Intermittent
Offshore Wind	High and uncertain	Medium	High	High	Not Linked	Intermittent
Biomass	Medium	Medium	Medium	Medium	Not linked	Flexible
Nuclear	High	Long	Medium	Medium	Not linked	Inflexible
CCS (Gas or Coal)	High and uncertain	Long	High	Unknown	Somewhat aligned	Untested

28. Overall the Government assessment is that the current market will not provide signals for investments that will cost-effectively decarbonise the electricity system in the long term.

Investment signals to ensure Security of Supply

29. Today, the UK's electricity supplies are amongst the most reliable in Europe. Supply outages in GB are almost always the result of a physical interruption to the transmission and distribution system rather than a shortage of electricity generation.

30. Security of supply can be assessed by examining the likelihood of supply shortfalls. This is technically defined as "expected energy unserved (EEU)" and is a probabilistic assessment of both the likelihood of an involuntarily interruption and its likely size. The EEU can include both energy unserved because of voltage reduction[16] and that due to supply outages.

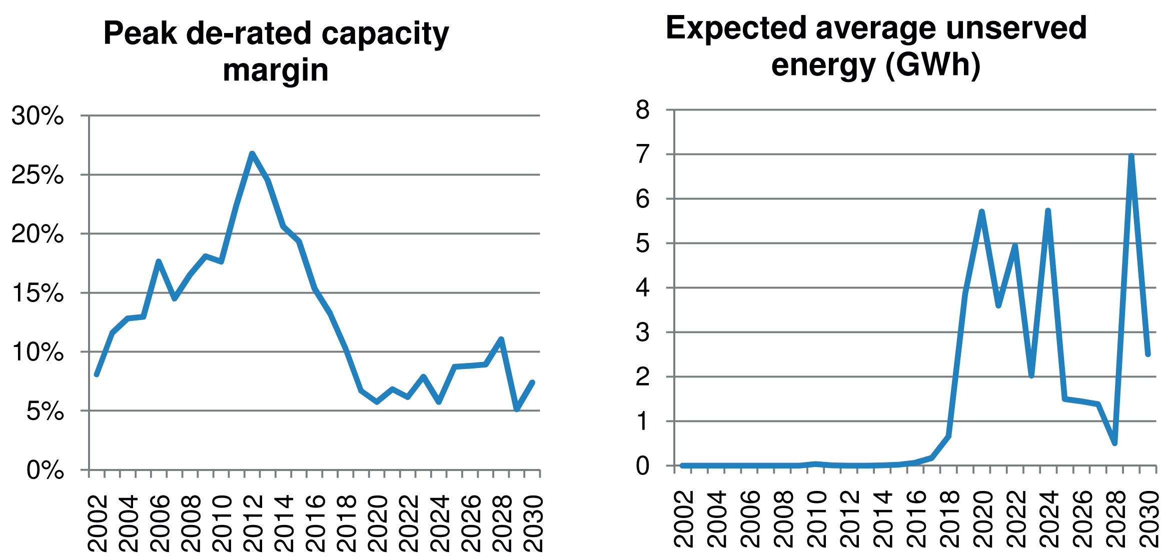
31. Current levels of EEU arising as a result of distribution level faults, for example trees falling on lines, are about 12GWh of outages per year[17]. To put this figure into context, the total electricity supplied in the UK in 2009 was almost

[16] In voltage reduction, the system voltage is reduced by a few %, and so performance of heaters, lights etc diminish a little. This has no significant impact on customers, but after a while systems start to compensate e.g. a heater may run longer, a consumer may turn more lights on.
[17] Dynamics of GB generation investment, Redpoint, 2007

400,000GWh[18] The EEU from generation related problems has been near zero (see figure 2).

32. As described below in figure 3, the Government expects that spare capacity will fall steadily over the decade, which would begin to yield higher levels of EEU (our modelling suggests there might be up to 8GWh in a single year (2029) from insufficient generation, not including distribution losses), making the system still more than 99.9% reliable. In the absence of any intervention capacity margins are likely to fall over the decade to settle at 5-11% from 2020-2030[19]. The following section explains why the current market arrangements may not provide the necessary investment signals to ensure adequate levels of security of supply.

Figure 3: Electricity Security of Supply Metrics[20]



33. There is a need to strike a balance between the desire for an electricity system that is as secure as possible, and the cost of any given level of security, which ultimately will be borne by electricity consumers. Estimates of the optimal level of security are highly uncertain and very dependent on estimates assigned to society's valuations of supply disruption. Some estimates of the cost of supply disruption are up to £30,000/MWh[21]. Using the above ranges for the cost of interruptions and comparing to the long run cost of a new entrant peaking plant[22], suggests that an economically optimal de-rated capacity margin[23] in the UK could be around 8-12%. This could result in an estimated EEU of around 0.5-4GWh per year. The Government expects that this level of EEU

[18] DECC (2010) Digest of United Kingdom Energy Statistics
[19] This could result in an EEU of around 0.5-7GWh.
[20] Capacity margins to 2009 are estimated using DUKES (2010) and Redpoint de-rating factors, thereafter based on the Redpoint EMR baseline simulation
[21] Based on Redpoint assumptions and Oxera Study (what is the optimal level of electricity supply security, 2005)
[22] £60/kW/year, Redpoint assumptions based on DECC Mott Mcdonald estimates (2010)
[23] An economically optimal margin range represents a range where the value that society places on having a certain amount of electricity security is equal to the costs of providing that security.

could be mitigated through voltage reduction rather than actual power cuts. In low-gas price scenarios the risks of much higher levels of EEU are greater. Less plant is built or more retired because plant revenues are lower (as electricity prices track the (low) gas prices). In some years these levels of EEU could pose significant risks to security of supply.

34. Our mix of electricity generation capacity should be diverse, so that problems with one technology or fuel do not lead to the failure of the entire electricity system. Diversity can be technological (a wide range of electricity generation technologies) and geographic (primary fuels imported from a wide range of countries). Diversity can also address uncertainty as it helps to address the issues around technology costs maturing at different rates over time, and so reduces the overall costs we might face if we put our faith in only one or two technologies.

Reasons for insufficient investment signals

35. While the current market provides incentives to encourage generators and suppliers to align electricity production with demand at all times, these incentives may not be strong enough to overcome the additional uncertainty that arises as we deploy intermittent renewables and decarbonise. As such, while investment in new flexible generating capacity would be brought forward without any Government intervention, the overall level would still result in levels of EEU that are higher than those experienced historically.

36. The Government has identified a number of issues with the way the market functions which could result in insufficient investment signals for flexible plant and thus pose risks to future electricity security of supply. These are summarised below and the Impact Assessment that accompanies this Consultation Document provides more detail:

- **The peak wholesale electricity price may not rise high enough (low peak prices):** under the current arrangements, peak wholesale prices[24] may not rise high enough to reimburse generators and therefore will not incentivise developers to invest in sufficient new capacity. The costs that National Grid incurs when balancing the system are not fully reflected in the cash out price and as a result forward market prices may also be too low, leading to insufficient investment.

- **Management of peak price uncertainty:** Under the current arrangements there is a risk that prices will not be sufficiently predictable and certain to be used as the justification for investments in new generating capacity. Markets are effective in dealing with such price uncertainty, including through long term contracting. However, because of low levels of liquidity, that suppliers have shorter time-horizons than generators and that suppliers may not hedge their risks fully because of the possibility of future government intervention,

[24] While wholesale prices need to become more volatile and to reach higher peaks in order to remunerate sufficient capacity the Government does not expect this volatility to be reflected in average retail prices.

levels of long term contracting in the wholesale electricity market may be too low to enable effective price signals for generation investments.

- **Policy uncertainty:** The UK electricity system is in the middle of a transformation to a low-carbon future. This creates significant uncertainty as the electricity price is increasingly influenced by Government intervention as opposed to market forces which investors are used to dealing with. This inherent policy uncertainty will have two impacts: firstly it will increase the value of a ‘wait and see’ approach resulting in delays in investments even where there is a price signal that suggests an investment would be economic, and secondly making the long-term price signal more unpredictable because it can be influenced by changes in policy.

- **Investment cycles in generating capacity:** In a market-based system, developers will decide when to invest based on expectations of future supply and demand and as such prices and revenues for new generation capacity. This leads to a cyclical approach to investments, as developers are incentivised to make new investments as the capacity margin becomes smaller (and wholesale prices rise) and slow down their investments as that margin increases. The effects of such investment cycles could lead to low capacity margins in certain years and have a negative impact on security of supply. This cyclical behaviour means that even if capacity margins are adequate on average over a number of years there may be some years in which they are lower than desirable.

- **Low levels of liquidity in electricity wholesale markets**: A liquid market makes for better price formation and stronger investment signals and therefore improves competition and general functioning of the market. In the GB market there is only a limited reference price over the longer-term. In such scenarios, the case for new investment is weakened, because of a lack of reliable price signals; this can deter new entry and competition in the sector. Ofgem is taking work forward, in parallel with the EMR process in order to further develop a package of reforms aimed at improving liquidity. We set out in Chapter 5 further analysis and possible solutions identified by Ofgem.

Additional reasons for insufficient investment in other flexible resource

37. Interconnectivity, demand response and storage all have the potential to provide additional diversity and flexibility to assist security of supply. However there are a number issues that currently inhibit their increased application.

38. **Interconnection:** recent GB interconnector projects have been developed as standalone activities outside the price controlled transmission business, where revenues are exclusively determined by auctions of capacity. For these projects, an exemption from aspects of EU legislation has been requested, to seek protection against regulatory intervention to cap profits or change the basis on which capacity is sold. By contrast, in other EU member states, it is

more common for interconnectors to be developed by TSOs with revenues underwritten by consumers.

39. **Demand Side Response (DSR)**: there are still significant barriers to full implementation of DSR, the most significant being:

- Insufficient price signals: The cash out price may be too low for industrial & commercial consumers. In the domestic and SME sector there are few Time of Use (ToU) tariffs available.
- Lack of half hourly metering**:** This technical requirement is important for the application of dynamic ToU tariffs.
- Settlement arrangements: Suppliers have little incentive to offer ToU tariffs as under current settlement arrangements, the benefit is shared across suppliers.
- Role of Distribution Network Operators (DNOs): DSR can play an important role in assisting DNOs to manage the network but they have no direct link to their customer base.
- Access to markets: Minimum 25MW requirement for trading means virtually no DSR is traded in the spot market; nearly all is contracted to National Grid for Short term Operating Reserve (STOR).

40. **Storage:** In terms of future investment in storage, high capital costs combined with uncertainty over the future market, in particular the levels of volatility we will see, are cited as the main barriers to further investment.

- **Uncertainty over future levels of volatility**: Wholesale price volatility is important to the commercial success of storage as arbitrage is fundamental to its business model: storage generally uses less expensive electricity in off peak times so that they are able to capture higher prices at other times.. There is considerable complexity in predicting levels of volatility as the market goes through a period of unprecedented transition.
- **High capital costs**: Most storage technologies are in early stage of development. The costs of many technologies do not compare favourably with conventional generation technologies[25]. Other possibilities, such as using electric vehicles to act as a store, are still uncertain.
- **Geographic limitations:** The only mature storage technology is Pumped Hydro. This technology is geographically limited and obtaining suitable sites may limit further build. However, whilst they may be limited, there are sites which are thought to be suitable and have potential for development.

Reasons for taking actions in the next few years

[25] http://www.decc.gov.uk/media/viewfile.ashx?filetype=4&filepath=Statistics/Projections/71-uk-electricity-generation-costs-update-.pdf&minwidth=true

41. Market participants will be faced with decisions regarding the Industrial Emissions Directive (IED), which comes into effect for existing plants on 1 January2016, in addition to their decisions on new build. In order to give clear signals to generation companies of the market structure they will face going forward it will be important to take decisions on any security of supply measures in time to influence the decisions of market participants. Operators have to decide by 1 January 2014 whether to take the "limited hours" option under the IED. The Government will also need to submit its "transitional national plan" to the European Commission by 1 January 2013. Moreover in designing these interventions now the Government needs to ensure a co-coordinated approach in our decarbonisation policies and institutional reform programme.

The challenge of financing the transition to a low-carbon electricity system

42. Decarbonising GB's electricity system will require large amounts of investment in new low-carbon electricity generation, replacement of conventional plant, and in the transmission and distribution networks. New power plants and grid capacity are likely to cost over £110bn in capital investment to 2020. Of this, about £70-75bn is likely to be investment in new generation capacity, and the remainder in the electricity networks[26]. Moreover, energy utilities could also face additional financing requirements in their supply and retail businesses, for example associated with the roll out of Smart Meters, gas transmission and distribution and renewable heat policies that could take the investment challenge toward £200bn. The overall investment rate in generation is likely to be double the level seen in this past decade.

43. This rising demand for capital may need to be met in the context of a shrinking supply of capital from the incumbent energy utilities. Financial analysts and other experts have suggested[27] that utilities are under pressure to moderate or lower their capital expenditure programmes and to find higher-yielding and higher-growth opportunities as a result of high debt levels, pressure to grow dividends , falling share prices and increased pressure on credit ratings. It is likely that they will exercise maximum discretion in how much generation capital expenditure they undertake in Great Britain, as these assets have longer development and construction periods and more volatile returns. In comparison, investment in the regulated network businesses (which have to be subject to price regulation because they are natural monopolies), is likely to be relatively easy to finance. This is because the nature of the regulated regime, which guarantees returns is low risk (and therefore attractive for debt financing). The financing challenge may therefore be more acute in investment in new electricity generation assets than in other parts of the electricity market albeit a number of utilities have been disposing of their regulated operations in recent times. Moreover, many energy utilities operate around the world, so

[26]Redpoint EMR modelling for capacity build rate scenarios, DECC estimation of demand for capital based on capital cost assumptions from Mott McDonald (2010) "UK Electricity Generation Costs Update".
[27] Citigroup Global Markets (2010) 'The €1trn Euro Decade – Revisited'.

projects in the UK will need to compete with projects elsewhere in the world for capital.

44. Because there are so many factors involved, it is difficult to say exactly how much capital might be forthcoming from the utilities themselves. Industry estimates vary, but there seems to be a broad consensus that the existing, vertically-integrated "Big 6" utilities[28] may struggle to invest in low-carbon generation at the scale and pace required to meet the UK's targets between them [29]. While additional sources of finance will be important, other developers are essential. Indeed, a third of on-shore and offshore wind projects in the pipeline at the moment are being developed by companies outside the "Big 6" like DONG Energy, Vattenfall and Statoil[30].

45. If existing developers are unable to deliver the overall level of capital expenditure over the next decade, then meeting the investment challenge in the UK will require one or more of the following:

- Current utility investors increasing the amount of capital they invest in the UK compared to other countries where they operate; and/or
- Greater recycling of capital from utilities to new entrants once construction is complete (particularly by bringing in debt through project finance); and/or
- Greater participation from new entrants in the construction phase of projects.
- New participants in the supply side of the market providing tariffs and services built around smart meters would increase total balance sheet capacity and may allow those firms currently able to develop generating assets to bring forward more projects.

46. Creating a longer-term policy framework for electricity market reform, and providing greater revenue certainty to investors and lenders, is likely to assist with all of the above, albeit that some current market participants welcome electricity price risk. At the same time, discussions with investors and lenders have indicated that there are a large number of risks associated with low-carbon generation (such as planning, grid access, technology, construction and long-term availability) which may have a much greater effect in constraining the availability of finance than revenue uncertainties.

47. The 2010 Spending Review reaffirmed Government's commitment to establish a Green Investment Bank, announcing an initial capitalisation of £1 billion funding and further funding to come from proceeds of future sale of

[28] Centrica, EdF, Eon, SSE, Iberdrola, RWE
[29] For an analysis of overall low-carbon energy financing requirements, see Citigroup Global Markets (2010) op cit., and Ernst and Young (2010) 'Capitalising the Green Investment Bank'. For an analysis of the challenge in new nuclear build, see KPMG (2010) op cit., and for offshore wind, see PricewaterhouseCoopers (2010) 'Meeting the 2020 Renewable energy targets: Filling the offshore wind financing gap'.
[30] DECC analysis of National Grid's Transmission Entry Capacity database, projects under constructions and projects with consent (some of these projects might not materialise) and Round 1 and Round 2 offshore wind projects.

Government-owned assets. Its design and the financial products it will provide are being developed to complement measures implemented through electricity market reform in order to tackle remaining financing gaps. It will have an explicit mandate to tackle risk that the market currently cannot adequately finance and will look to catalyse further private sector investment and facilitate the entrance of new types of investor into green infrastructure, so that the finance gap is reduced. It is anticipated that the design of the GIB will be complete and published by May 2011, and it should be operational by September 2012[31].

Section Conclusion

48. Overall our assessment is that the current market will not deliver on the Government's objectives for decarbonisation (including on renewables deployment), security of supply or affordability for consumers.

Question 1: Do you agree with the Government's assessment of the ability of the current market to support the investment in low-carbon generation needed to meet environmental targets?

Question 2: Do you agree with the Government's assessment of the future risks to the UK's security of electricity supplies?

[31] http://transparency.number10.gov.uk/transparency/srp/view-srp/44

CHAPTER 3 – Decarbonisation options for reform

Chapter Summary:

The EU ETS continues to be the primary EU wide policy driving decarbonisation across a number of sectors in the UK economy and the UK Government continues to work within the EU for a tightening of the cap on the EU ETS. However, a growing body of evidence suggests that this may not be currently be sufficient to decarbonise the electricity sector at the pace required for a cost-effective trajectory to our long term (2050) targets.

DECC's 2050 analysis suggests that for the UK to cost-effectively meet our 2050 targets, the electricity sector will need to decarbonise during the 2030s. In some scenarios, for example as set out by the CCC recently, the electricity sector may need to decarbonise even more rapidly (in order to facilitate the decarbonisation of other sectors).

The Coalition Agreement set out three reforms to the electricity market that could contribute to the achievement of the Government's renewable and decarbonisation objectives in the electricity sector: action to support the carbon price, introducing a system of low-carbon generation revenue support (a feed-in tariff or FIT) and the introduction of an emissions performance standard (EPS).

The Government has undertaken internal analysis, engaged informally with stakeholders including potential investors (with support from Infrastructure UK) and has reached the following conclusions:

- a carbon price support mechanism should play an important role as part of an overall package of reforms.;

- the Government's lead option for a feed-in tariff – a contract for difference – designed to support revenues for low-carbon generators , but maintain the efficiency of generation within the market; there are a number of design and implementation issues which need further consideration during the course of this consultation. If these cannot be resolved,. The Government's preferred alternative is a premium FIT; and

- an Emissions Performance Standard would complement the reforms proposed above, by ensuring that alongside incentives to build low-carbon, the market is prevented from building the most carbon-intensive forms of electricity generation: unabated coal-fired power stations.

The rationale for choosing the FIT with CfD as a lead option is that it gives the best balance between the Government's objectives of decarbonisation (including renewables), security of supply and affordability. The FIT with CfD model is designed to:

- gives a high level of confidence that the Government's emission reduction targets are met even in scenarios with lower gas prices or higher electricity demand, without the need for additional intervention;
- maintain exposure to the short-term electricity price signal, incentivising efficient operational decisions by generators, which also contributes to security of supply;
- keep costs down through enabling a lower cost of capital, by providing long-term contracts and greater certainty;
- Help enable smaller generators to enter the market as well as attract a wider range of sources of finance, including more institutional investment because of the long-term contracts and greater revenue certainty

Finally a FIT with CfD works well with the carbon price – providing a natural stabilisation mechanism which avoids excess rents and thereby keeps costs down.

1. The Government set out three decarbonisation policies in the coalition agreement:

- to introduce a floor price for carbon;
- to establish a full system of feed-in tariffs in electricity - as well as maintenance of banded Renewable Obligation Certificates; and
- to establish an emissions performance standard that will prevent coal-fired power stations being built unless they are equipped with sufficient carbon capture and storage (CCS) to meet the emissions performance standard.

2. This chapter considers how the above policies perform against the government's objectives (decarbonisation, security of supply and affordability) and the key criteria (cost-effectiveness, durability, practicality and coherence). The chapter also considers the impact of the different policies on the public finances. The coherence of these policies with each other and the potential security of supply policies is mainly discussed in chapter 5.

3. The assessment of the policy options presented in this chapter is a summary of analysis by DECC and HMT, and discussions with stakeholders. A key part of the DECC analysis was modelling of the policies by Redpoint Energy[32]. The Redpoint model simulates investment and generation behaviour out to 2030 under different policy frameworks. Investment decisions are based on

[32] Electricity Market Reform, Analysis of policy options, Redpoint (Dec 2010).

comparing the risk-adjusted long-run marginal costs (LRMC) of all generating technologies by investor type with the expected revenues. This is a simplification of how investment decisions are made and so the results presented below are an illustrative assessment of how the different proposals would affect low-carbon investment.

Decarbonising the electricity sector on the path to the 2050 target

4. In order to cost-effectively meet the Government's 2050 emissions target, the electricity sector will need to be largely decarbonised during the 2030s. DECC's 2050 Pathways Analysis suggested that the electricity sector would need to be largely decarbonised during the 2030s. The Government does not have a 2030 emissions intensity target for the electricity sector, nor a renewable energy target for 2030 but for the purposes of the modelling, it was necessary to make an assumption about the desired level of emissions from the electricity system in 2030, the evolution of the demand for electricity to 2030 and an assumption about meeting the 2020 renewables target (modelled as 29% renewable electricity by 2020). The performance of the options, in terms of the costs and risks of using them to reach these outcomes, have then been compared. A comprehensive report prepared by Redpoint Energy is available alongside this consultation[33].

Box 2: Modelling assumptions to 2030

The level of emissions from the electricity system in 2030 was set based on the assumption that investors effectively have perfect foresight of the DECC traded sector target-consistent carbon price projections. This results in an emissions intensity of around 100gCO_2/kWh by 2030. This is similar to the figure previously recommended by the Committee for Climate Change in 2009. The recent publication by the CCC for the 4th Carbon budget recommends a lower figure of around 50gCO_2/kWh as a medium scenario.. It compares to a business as usual grid intensity of approximately 200gCO_2/kWh. This level was chosen as an illustrative level for the purposes of modelling the policies under consideration. The level does not represent a Government target for grid carbon intensity in 2030. Decisions on the expected level of the reductions in emissions from the electricity sector needed in the period 2024 to 2028 will be taken next year when the Government sets the UK's fourth carbon budget.

The modelling assumed a take-up of renewable electricity consistent with the lead scenario of the Renewable Energy Strategy at around 29% of total electricity generation by 2020. In the 2020s it is assumed that the take up of renewable electricity generation would be consistent with a level that is incentivised by the rising carbon price. When investors have perfect foresight of this rising carbon price, the level of renewable electricity in 2030 is around 35%. The modelling assumes that the incentives are set differently in every option so that this level of renewables is achieved. This assumption is different to the modelling approach used in the Carbon Price Support consultation where the level of renewable incentive is held constant across different scenarios in order

[33] Op cit, Redpoint (Dec 2010).

to isolate the impact of carbon price support. All other assumptions are consistent.

The assumptions for other key variables affecting investment, namely levelised costs, electricity demand and fossil fuel prices, are consistent with those used for DECC's updated emissions projections (UEP). Changing these assumptions would have an impact on the modelling results.

There are important limitations to the modelling (the implications of which are discussed in the Impact Assessment accompanying this consultation), including:

- The administrative costs of both the transition and the options themselves;
- The modelling assumes that there would be no short-term impact on investment following a major change of electricity market arrangements;
- The modelling also assumes that incentives are set at the correct level;
- The modelling assumes that there is no financing constraint; and
- The model assumes that there are liquid markets and perfect competition.

Costs and benefit calculation - the costs of decarbonisation

5. The modelling work for EMR has estimated the overall costs and benefits to society of the various policy options, or 'net welfare'. Net welfare is measured in terms of the net present value (NPV), which is the sum of all the costs and benefits associated with the policy, with an adjustment made to reflect the time at which the different costs and benefits occur (known as discounting).

6. All decarbonisation targets and policies involve upfront costs. As the Stern Review set out these costs are outweighed by the long term benefits of avoiding dangerous climate change. The policy packages considered in this consultation all meet the Government's decarbonisation targets and so they involve costs in the next decades. The analysis published in the impact assessment quantifies these costs, but does not capture the long term benefits of avoiding dangerous climate change. This is due to limitations in the modelling that is possible. The cost benefit calculation is therefore necessarily partial. This is why the analysis shows that there are overall costs to society under all the options for reform when compared to the baseline[34] and as a consequence the NPV is negative. Some of the potential benefits which are not fully captured:

- The costs and benefits are estimated between 2010 and 2030 because the modelling cannot currently be extended beyond that date. The benefit/cost

[34] The baseline assumes that no new policies are introduced and that the market continues to operate with the current set of policies operating as currently designed.

ratio improves significantly towards the end of this period as the carbon price increases. If there were a suitable modelling approach to consider costs and benefits over a longer period, for example over the complete lifetime of the low-carbon generation technologies, the Government would expect the NPV would be positive.

- These calculations use DECC's central carbon price estimates to quantify the benefits from reductions in carbon emissions, which are consistent with the EU 2020 greenhouse gas target, prices beyond 2020 increase towards a level consistent with global action required to limit to CO_2[35]. If the 2020 EU target were increased to a 30% reduction on 1990 levels rather than a 20% reduction, carbon price estimates would be higher which would in turn improve the overall NPV.

- There are other benefits that are not captured in the analysis, including the innovation benefits of bringing forward the development of some technologies. These benefits would also improve the NPV.

7. Under a high demand scenario, the policies result in an overall benefit to society. i.e. a positive or zero NPV, in three of the possible packages looked at (the FIT with CfD package, the fixed FIT package and the Premium FIT package – see Box 11 in chapter 5).

Options to support low-carbon generation investment

Carbon price support

8. The carbon price support commitment is being considered as part of an HM Treasury and HMRC-led proposal to reform the climate change levy (and fuel duty) and is the subject of a separate consultation[36]. As a tax matter, and in line with previous public statements, decisions on the carbon price support mechanism will be taken at Budget 2011. This consultation document considers the other Coalition Agreement proposals and how they fit together when brought together as a package of reforms.

9. HM Treasury has published a consultation outlining proposals for introducing a carbon price support mechanism alongside this consultation document. Respondents with an interest in electricity market reform and this consultation should also review the Government's proposals for implementing this mechanism. This consultation on electricity market reform will not ask detailed questions about the carbon price support mechanism in isolation, but will consider how it could be combined with other reform options to create a coherent package to support investment in low-carbon generation.

[35] DECC, Carbon Valuation in UK Policy Appraisal: A Revised Approach, July 2009
[36] http://www.hm-treasury.gov.uk/consult_index.htm

10. Putting a price on carbon for UK electricity generation helps to increase incentives for investment in low-carbon electricity generation by improving the economics of low-carbon investment. This is because putting a price on carbon increases the wholesale electricity price, when that price is set by fossil-fuel fired power stations. It makes the economics of low-carbon technologies relatively more attractive than higher carbon alternatives, because low-carbon generators do not have to pay a price for carbon emissions.

11. The power generation sector and energy intensive industries[37] have needed to account for the cost of the carbon they emit since 2005 when the European Union Emissions Trading System (EU ETS, which is a cap-and-trade system) was introduced. The trading of EU carbon allowances (EUAs) has created a dynamic market in carbon so that emissions across the EU can be abated at least cost. From 2013, the EU ETS emissions cap tightens each year following a long-term trajectory, which provides certainty in relation to the environmental benefits of the system. However, for a variety of reasons, to date the carbon price has not been stable, certain or high enough to encourage sufficient investment in low-carbon electricity generation in the UK. Supporting the carbon price in the electricity sector in the UK will increase the incentives to invest in UK low-carbon generation.

Box 3: European Union Emissions Trading System (EU ETS)

The EU ETS will remain an essential prerequisite for reducing the carbon intensity of the UK power sector. Under any of the options explored in this consultation, the carbon price will still play a critical role in providing signals for the optimal operation of high-carbon generation (such as the choice between running coal or gas power stations), for the investment in low-carbon generation and the optimal choice of flexible technologies, such as between gas-generation or demand-side response technologies.

In options where new low-carbon investment earns all or part of its revenue from the wholesale market, the carbon price will serve to differentiate between low-carbon and high-carbon technologies. In options with a funding mechanism for low-carbon investment outside of the wholesale market, the carbon price will be an important benchmark for regulators in setting incentives. A strong and stable carbon price will therefore remain essential for the power sector as well as continuing to be the primary driver for emissions reductions in the other sectors of the EU ETS.

Furthermore, decisions at the European level through the EU ETS will continue to ensure international action is taken to tackle climate change.

12. To make the very large investment decisions needed in low-carbon generation capacity, investors require some certainty about future revenues (e.g. future electricity prices). Carbon price certainty is particularly important given the long

[37] From 2012 aviation will also be included.

life of low-carbon generation investments. If there is more certainty over future carbon prices, developers should include this as part of their investment appraisals. High levels of uncertainty over future profitability and rates of return could increase the cost of capital for investors and deter investment altogether. If uncertainty is too great, investment will either not go ahead or capital could be diverted into less risky forms of generation.

13. To enable a secure low-carbon transition in the UK power sector, the Government believes there is a strong rationale for complementary measures to the EU ETS so as to provide greater certainty and support to the effective carbon price faced by the sector. This could be achieved by introducing a carbon price support mechanism, as is being proposed by the Government. Box 4 explains how the Government proposes to support the effective carbon price in the electricity generation sector. The details of how the policy would be implemented are being considered as part of the separate HM Treasury/HMRC consultation.

Box 4: How carbon price support mechanism would work in practice

The Government proposes to introduce a carbon price support mechanism from 1 April 2013 to support investment in low-carbon generation. This will be achieved by the climate change levy (CCL) and fuel duty being levied on all fossil fuels used to generate electricity in the UK.

In most cases, fossil fuels currently used to generate electricity are exempt from CCL. The Government proposes to remove these CCL exemptions and to tax these commodities at rates that take account of their average carbon content. These rates will be known as the 'CCL carbon price support rates', and will be different from the main CCL rates (gas, coal, LPG and electricity), which will be retained.

Oils are not subject to CCL but fuel duty is payable at the point oil leaves the refinery. Currently, the duty can be reclaimed in full by the electricity generator but, as part of the carbon price support mechanism, the Government proposes to reduce the amount of fuel duty that can be reclaimed.

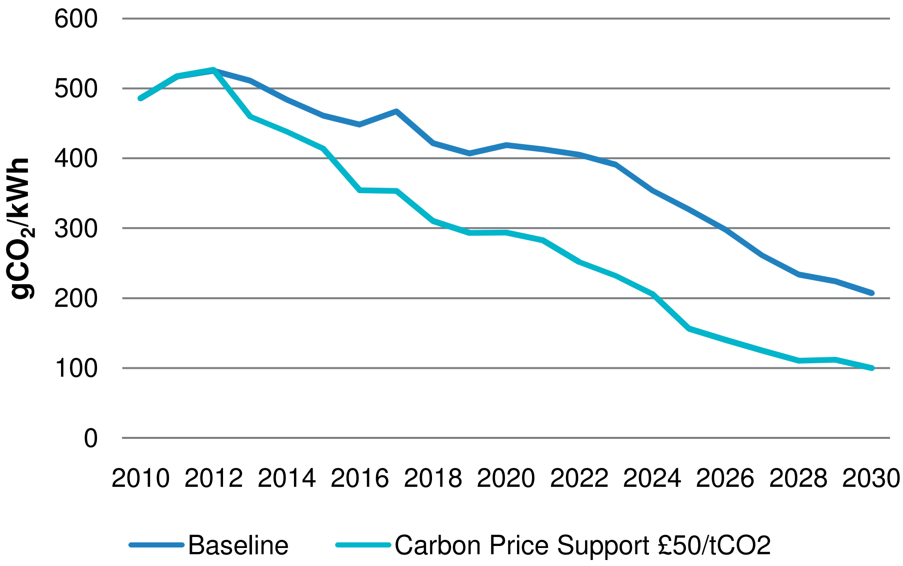
Other more detailed features of the Government's proposal include:

- electricity used to generate further electricity will remain exempt from CCL;
- the CCL liability of electricity supplied to the final consumer arising from generation using fossil fuels will be unchanged, as will the treatment of imported electricity;
- fossil fuels used to generate electricity in the UK that is subsequently exported will be liable to the relevant carbon price support rates;
- all fossil fuels burnt in CHP stations will be subject to CCL (at the carbon price support rates) or fuel duty regardless of their rating through the CHP Quality Assurance (CHPQA) programme;
- subject to State Aid approval, to provide a partial relief for fossil fuels burned in carbon capture and storage enabled power stations; and
- supplies of fossil fuels to auto-generators will continue to be liable to CCL and fuel duty but at the relevant carbon price support rate. Auto-generators will no longer be able to reclaim the CCL or fuel duty charged on the fossil fuel they use to produce electricity which is subsequently supplied to the electricity transmission and distribution networks.

Meeting the Government's objectives – Carbon (and Renewables), Security of supply and Affordability

14. The modelling undertaken for this project indicates that introducing a carbon price support mechanism could help the UK to meet its decarbonisation objectives. The Government sees a carbon price support mechanism as part of a wider package of reforms. If introduced without other market changes as the sole policy to meet the decarbonisation targets, the carbon price would be need to be increased significantly above the level delivered through EU ETS. The modelling shows that it would need to reach £50/tCO_2 by 2020 and then increase in a straight line to the 2030 target consistent price of £70/tCO_2. The figure below shows the carbon emissions trajectory that would result from using the carbon price support mechanism as the sole tool to meet the level of emissions in 2030 set in the modelling.

Figure 4: Decarbonisation trajectory under £50/tCO_2 Carbon Price Support, compared with the baseline



15. The separate HM Treasury/HMRC carbon price support consultation discusses the impact of the policy on investment in low-carbon generating capacity at different indicative levels of price support: a carbon price of £20/tCO_2 by 2020, £30/tCO_2 and £40/tCO_2 (after 2020, the trajectory rises to meet the 2030 target consistent carbon price of £70/tCO_2 in all of the scenarios). The HM Treasury and HMRC consultation does not consider the £50/tCO_2 option because it would mean increasing the level of price support quickly and to a relatively high level by 2020. However, as part of a package (and therefore, targeted at a lower carbon price, the policy can play an important role in encouraging the decarbonisation of the electricity sector. Chapter 5 discusses the role it could play in a package of measures in more detail.

16. The policy could from an important part of a package to reduce carbon emissions from the electricity sector, by: firstly encouraging more investment in

low-carbon generation and secondly encouraging a switch in dispatch decisions of existing plant from high-carbon to lower-carbon ones (i.e. coal to gas switching). The key factor in the effectiveness of the policy is the reaction of potential investors, and whether the mechanism is “bankable” for the purposes of raising finance for new low-carbon generation investments.

17. On its own, the mechanism would not be able to encourage the investment needed in renewable generation to meet the EU 2020 target, because additional support is needed reflecting the higher cost of renewables. Therefore, it would need to be combined with a continued RO, or a feed-in tariff mechanism to be able to meet both the decarbonisation and renewable objectives.

Performance against criteria[38]

Cost-effectiveness

18. Carbon price support has both positive and negative characteristics that must be considered together to form an overall view on the mechanism’s cost effectiveness. The modelling indicates that all other things being equal, the costs of meeting the indicative 2030 decarbonisation level are greater when using a carbon price support mechanism as the sole policy instrument than when some of the forms of feed-in tariffs discussed below are used without any accompanying changes as part of an overall package of reforms. A major factor in the difference in costs from the most cost-effective policy (feed-in tariffs with a contract for difference) is the smaller anticipated reduction in the cost of capital. Table 2 below sets out the key numerical outputs from the modelling undertaken to support this project:

Table 2: Modelling results on costs of delivering 2030 decarbonisation of 100 gCO_2/kWh

Overall cost to society[39] (£bn NPV)	5.8
Average consumer prices[40] (2010-2030, real 2009 prices) (£/MWh)	95
Difference in prices compared with baseline (£/MWh)	3.6
Average annual domestic bill (2010-2030, real 2009 prices[41]) (£)	562

[38] The separate carbon price support consultation document is where the Government has set out fully the arguments around the merits of this policy. That consultation document considers the cost-effectiveness, policy-effectiveness, practicality and impact on public finances of the carbon price support mechanism. The assessments contained in this chapter focus on the advantages and disadvantages of using the policy to deliver the electricity market reform modelling scenario, using the criteria specified for this project only.
[39] Reduction in net welfare relative to the baseline scenario.
[40] Redpoint modelling. Prices only cover generation costs and Government support costs, These do not include transmission and distribution costs.
[41] DECC estimates based on Redpoint modelling.

19. However, an important attribute of the carbon price support mechanism is that it directly targets the carbon externality by putting a price on emissions and maintains the role of carbon pricing and the "polluter pays" principle at the centre of the Government's decarbonisation strategy. In doing this, it also maintains more of the competitive market signals that create incentives for efficiency, which are a feature of the current UK electricity market (and are discussed in more detail below as one of the advantages of premium feed-in tariffs). For these reasons, the Government believes the carbon price support mechanism should play a key role as part of a wider package of market reforms.

Durability

20. The main issue of durability relates to how investors react to the policy; if the policy is credible over the long term and investors can "bank" it and build into their economic appraisals, the policy will be more durable and effective. One factor to consider is that tax rates can vary whereas contracts (if the kind potentially used to implement a feed-in tariff scheme) are legally enforceable. Although the policy can be designed in a way to maximise its predictability for investors, there will always be some long-term, uncertainties over the policy. There is a range of factors that affect investment decisions and their importance varies across different generation technologies.

Practicality

21. The implementation of the carbon price support mechanism is discussed in the separate HM Treasury / HMRC consultation. Broadly speaking, because it would be implemented through amending existing taxes the Government expects it should be reasonably straightforward to implement and with limited risk. Those already dealing with Government to pay the CCL or reclaim fuel duty will generally be familiar with the tax regimes and other parties interacting with the mechanism would already be familiar with the concept of carbon pricing (through the EU ETS).

Public Finances

22. The carbon price support policy is implemented through the tax system as opposed to through public expenditure in the way a feed-in tariff system operates. Carbon price forecasting is inherently uncertain and any estimate of Exchequer revenue impacts would depend upon the future traded (EU ETS) carbon price relative to the target price The policy would be in line with the commitments set out in the Coalition Agreement to:

- increase the proportion of tax revenues from environmental taxes; and
- make the tax system more competitive, simpler, fairer and greener.

Low-carbon generation revenue support (feed-in tariffs, supplier obligations and regulated asset bases)

23. Carbon price support on its own is unlikely to provide enough certainty on the Government's policy direction to allow sufficient investment in low-carbon technologies needed to meet the UK's objectives. As such, Government has assessed a number of policies designed to give low-carbon investors more certainty over future revenues:

24. **A Low-carbon obligation** on suppliers, essentially an extension of the Renewables Obligation. This would require suppliers to source a certain percentage of their generation from low-carbon generation. Suppliers would have to present certificates to demonstrate they had met their obligation and these certificates would have a value, giving the low-carbon generator an additional revenue stream.

25. **Feed-in tariffs (FITs),** such as those used in countries like Germany and Spain. Feed-in tariffs are long-term contracts between government (or an entity on behalf of government) and a low-carbon generator, giving a guaranteed tariff or price e.g. for 15-20 years. In some cases this contract also gives a guaranteed buyer for the electricity. They are normally based on electricity sold (i.e. on a MWh basis) but can also be signed on an availability basis (i.e. a MW basis). With a FIT contract the investor gets certainty about the level of support when the contract is signed. This is better than currently under the RO where an investor will not be sure of the number of ROCs they will receive until their installation is built and connected to the grid (accredited). There are three main forms of FIT:

- **Premium FIT**: a static payment which generators receive in addition to their revenues from selling electricity in the wholesale market. This is one of the models of FITs used in Spain;

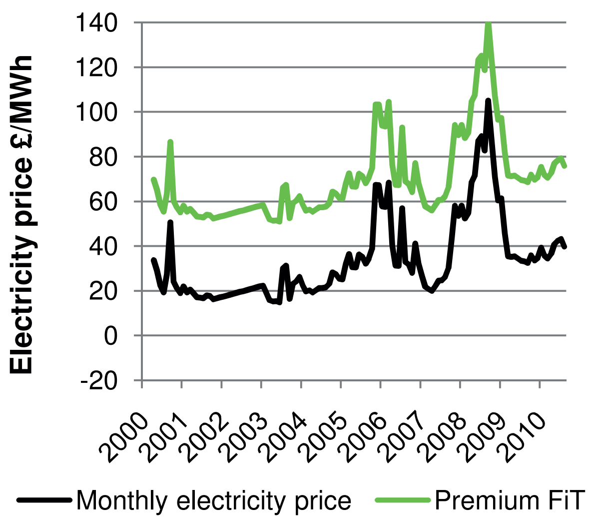
- **Fixed FIT**: a static payment which generators receive in place of any revenues from selling electricity in the market. This is the model of FIT used in Germany;

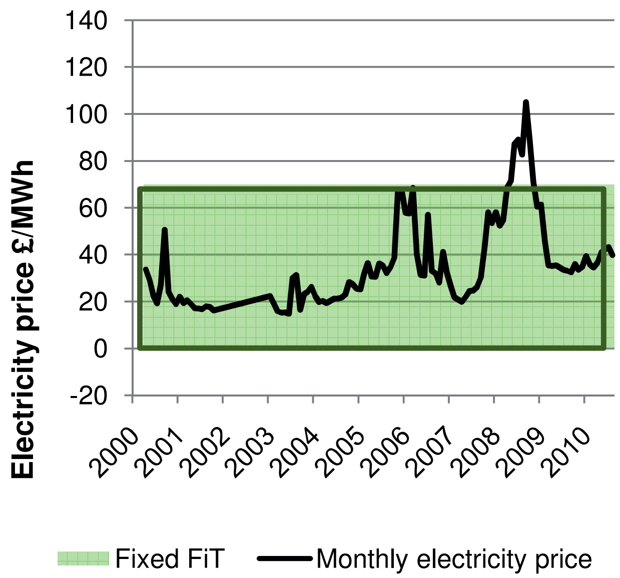
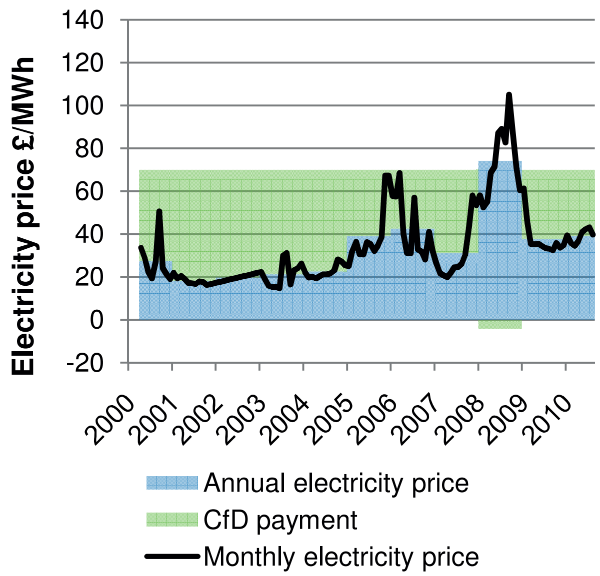
- **FIT with a Contract for Difference (CfD)**: a long term contract set at a fixed level where variable payments are made to ensure the generator receives the agreed tariff (assuming they sell their electricity at the market price). The FIT payment would be made in addition to the generator's revenues from selling electricity in the market. The CfD can be a two-way mechanism that has the potential to see generators return money to consumers if electricity prices are higher than the agreed tariff. This is the model of FIT used in the Netherlands for renewables (though they call it a "sliding premium") and in Denmark for offshore wind. It provides a similar level of revenue certainty to a Fixed FIT, but by setting the level of support according to the average price preserves the efficiencies of the price signal, i.e. generators will have an incentive to sell their output above the average price as they will keep any upside. This is shown in Figure 5 below;

26. **Regulated Asset Base (RAB):** extending the current approach used to finance the transmission and distribution networks into low-carbon generation. Network licensees are allowed to add efficiently incurred capital expenditure to their RAB and to make a regulated return on that investment in line with their average cost of capital through setting tariffs for the use of their network. The level of return is set by the regulator.

27. All of these mechanisms could be set at different levels for different technologies and the levels could be determined either through government setting the levels based on cost studies and consultation with the industry or through some form of auctioning or tendering (see Chapter 6 for more detail).

Figure 5: Models of Feed-in Tariff (FIT)

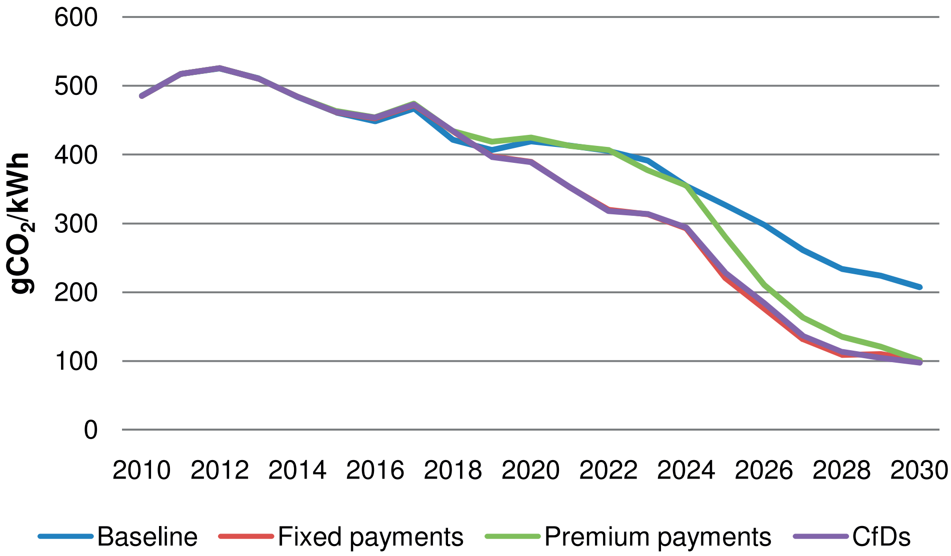
Premium FIT Pays a fixed premium on top of the variable wholesale electricity price.	

Fixed FIT Pays one fixed tariff per unit of electricity, regardless of the wholesale price.	
FIT with CfD Generators sell their electricity into the market, then receive a top-up payment (or, as the 2008 CfD payment year illustrates, may repay revenues). The top-up payment or repayment is calculated as the difference between the average market wholesale price and the agreed tariff level.	

Meeting the Government's objectives – Carbon, (including renewables), Security of supply and Affordability

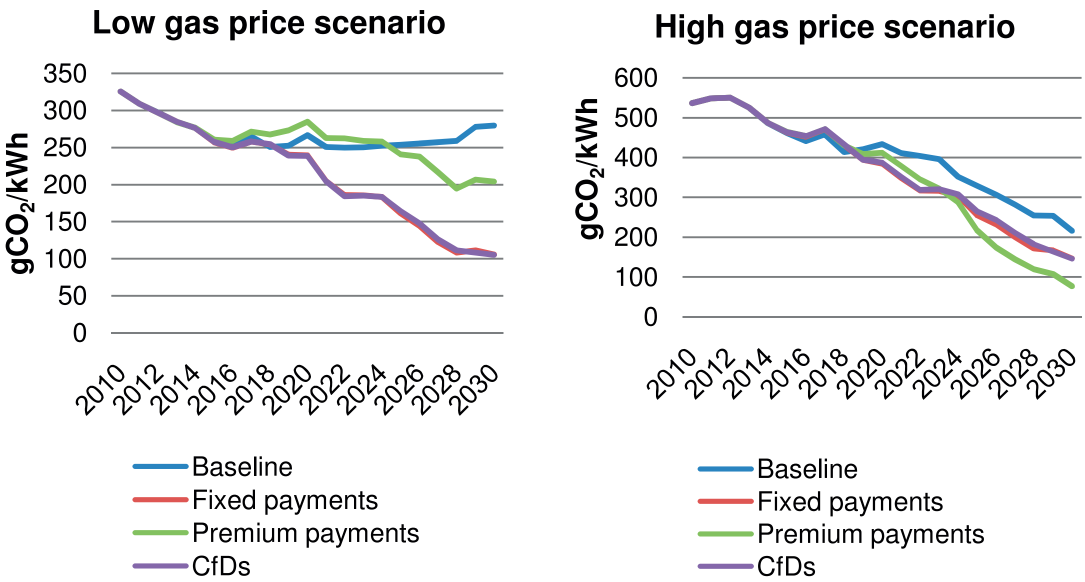
28. The modelling indicates that any of the three models of FIT could enable the UK to meet its renewable and decarbonisation objectives in the central scenario for gas and carbon prices. The figure below shows the carbon emissions trajectory that would result from using each of the different models as the sole policy to meet the level of emissions in 2030 set in the modelling. The main conclusion is that the cumulative emissions to 2030 are highest under the premium FIT option, because based on the modelling, investments in low-carbon are expected to take place at a later date.

Figure 6: Decarbonisation trajectory under each design of FIT, compared with the baseline case



29. Under a low gas price scenario or a high electricity demand scenario a fixed FIT or a FIT with CfD would give greater confidence in meeting the Government's long term decarbonisation objectives. This is because, unlike with the premium FIT, under the CfD and fixed FIT models, the long-term electricity price does not significantly affect the overall returns earned by low-carbon generators. A premium FIT does not automatically adjust to differences in electricity prices (driven for example by low gas prices or the carbon price) and therefore would not automatically ensure that the decarbonisation objectives were achieved in these scenarios. However, the Government could of course manually adjust the premium tariffs for new installations to ensure that low-carbon generation remained attractive, such that the same decarbonisation targets were achieved. In such a scenario, existing installations would continue to receive the original (lower) levels of support through the scheme. Similarly, if gas prices rise above central expectations (the high-gas price scenario), then support levels (for new generating stations) could be reduced for new installations while achieving the same decarbonisation outcomes.

Figure 7: Decarbonisation trajectory under each design of FIT, compared with the baseline case in low and high gas price scenarios

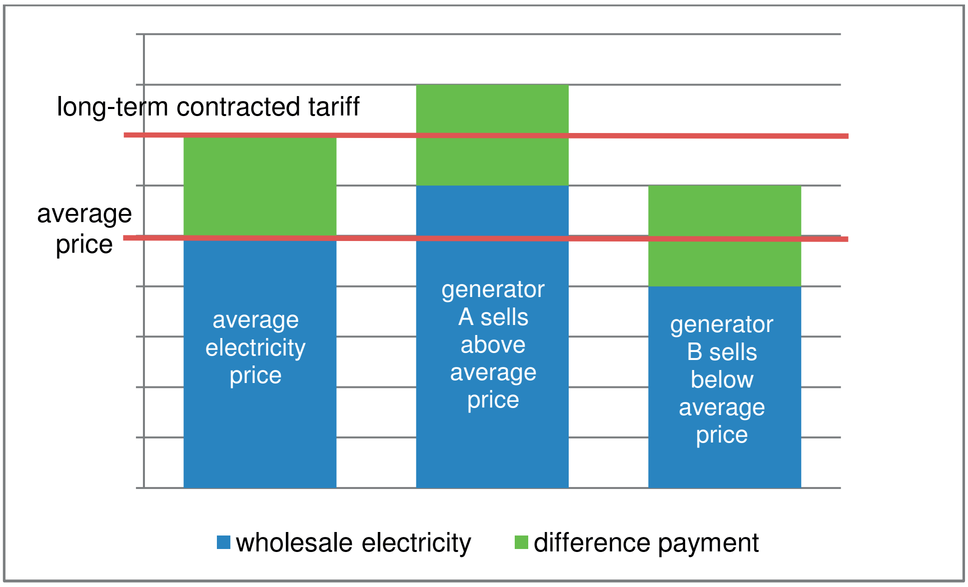


30. The key impact on security of supply of introducing any model of feed-in tariff is the increase in the proportion of intermittent (wind) and inflexible (nuclear) generation that may be on the system in the 2020s. This is because they provide greater incentives to invest in low-carbon generation. However, a fixed FIT would additionally remove the market price incentive to dispatch electricity efficiently. This could impact negatively on security of supply, requiring more balancing to be done by the rest of the generation fleet and increasing balancing costs.

31. A FIT with CfD exposes generators to the electricity price signal in the short term meaning that they will have an incentive to make efficient operational decisions about despatch and maintenance[42]. The FIT with CfD does this by specifying a tariff in the contract, but requiring generators to trade their electricity. Part of their revenues will therefore come from selling their electricity in the wholesale market on top of which they may be eligible for a top-up payment to ensure they get the tariff specified in the contract. This is illustrated in Figure 8 below which shows that any top-up payment is calculated against the average electricity price. So individual generators can receive slightly higher (or slightly lower) revenues than the tariff by selling their electricity slightly above or below the average price.

[42] NREL "A Policymaker's Guide to Feed-in Tariff Design" (2010)
Fraunhofer Institute "Evaluation of different feed-in tariff design option" (2008)

Figure 8: Revenues for different generators under a CfD scheme based on ability to sell above the average price



32. Affordability is the third objective the Government has emphasised will drive its energy policy. The impact on consumer bills will be determined both by the level of decarbonisation targeted and the choice of feed-in tariff design. The desired decarbonisation trajectory has not yet been set. The Government considers that, on the basis of the trajectory modelled, all three designs for a feed-in tariff limit the impact on consumer bills: the increase in average consumer electricity price compared to the baseline is less than 3% in all cases[43]. However, a fixed FIT and FIT with CfD have lower impact on consumer bills than a premium FIT (see Table 3 below). The FIT design with the lowest impact on consumer bills is the FIT with CfD. This is because this instrument provides enough revenue certainty to enable a lower cost of capital for investors and therefore lower costs to consumers. By providing a more stable return which automatically adjusts to the electricity price a FIT with CfD also avoids excess rents when the electricity price is high. In this way, the mechanism will also stabilise consumer bills.

Performance against criteria

Cost-effectiveness

33. The modelling indicates that the two most cost-effective models of FIT were fixed FITs and contracts for difference. Table 3 below sets out the key numerical outputs from the modelling undertaken to support this project. The table illustrates the relative costs of the different options. The overall costs will depend on the decarbonisation trajectory chosen.

[43] Op cit, Redpoint (Dec 2010)

Table 3: Modelling results on costs of delivering 2030 decarbonisation of 100gCO_2/kWh

	Premium FIT	Fixed FIT	FIT with CfD
Overall cost to society (£bn NPV)[44]	6.7	3.8	3.9
Average consumer prices (2010-2030, real 2009 prices) (£/MWh)[45]	94	91	91
Difference in prices compared with baseline (£/MWh)	2.5	0.1	-0.3
Average annual domestic bill (2010-2030, real 2009 prices) (£)[46]	559	550	548
Difference in average domestic annual bill compared with baseline (£)	8	-1	-2

34. A key factor which drives the difference in cost-effectiveness between the models of FIT is the transfer of different risks from the generator to the Government. Generally speaking, the more risks transferred, the lower the financing costs, or cost of capital for a low-carbon generating project. This lower cost is reflected in a lower level of public support needed to bring forward the investment. While transferring risk reduces the cost of capital, it also reduces the exposure generators will have to competitive market forces and efficiency incentives. It also means that the Government is taking on risks that have previously been borne by generators.

35. To supplement the modelling results, the Government has also considered the impact that the different models of FIT might have on attracting new entrants and new sources of finance to invest in low-carbon electricity generation. Chapter 2 highlighted the scale of the investment challenge: while the Government would expect the investor community to respond to the increasing maturity of the renewables and low-carbon generation market by providing new sources of finance, given the scale and pace of investment needed to meet the UK's targets at the end of this decade, means there are risks to not taking action now to attract new sources of finance.

36. Compared with the baseline (i.e. low-carbon support limited to renewables), the Government expects all of the models of FIT to be able to attract new investors in low-carbon generation more generally. However, because (as per Box 5 below) they result in a lower risk investment, fixed FITs and CfDs might be more attractive to a wider group of investors – in particular, smaller independent generators and institutional investors.

[44]Figures represent losses in net welfare relative to the baseline scenario.
[45] Prices only cover generation costs and Government support costs, These do not include transmission and distribution costs
[46] DECC estimates based on Redpoint modelling

37. The route to market for electricity is particularly important for smaller independent generators. Under a FIT with CfD model there are several ways in which this could be improved – but key to these considerations is the liquidity of the wholesale market. For a longer discussion of liquidity see Chapter 5.

38. In addition to the actions taken through EMR, government is further developing the Green Investment Bank proposals announced at the 2010 Spending Review.

Box 5: FITs, revenue certainty and the cost of capital

FITs provide greater certainty on future revenues to investors than the current Renewables Obligation. Greater revenue certainty means that investors can borrow money at a lower cost of capital (or equivalently that the hurdle rates for a project can be lower). This means that the policy ultimately costs less money, which reduces the costs to consumers.

Low-carbon investments use both debt and equity, and debt is generally cheaper than equity. The Weighted Average Cost of Capital (WACC) is the average of the costs of these types of financing for a project, taking into account the different proportions of debt and equity. The WACC is affected by a range of parameters. Lowering the risks associated with a project reduces its WACC, both because investors are willing to accept lower returns for managing correspondingly lower risks, and because it enables projects to raise a greater share of cheaper debt finance.

An important risk associated with low-carbon generation is how much revenue the plant will earn over the life of the investment. The greater the certainty of revenues that can be offered to investors, the lower the project cost of capital. So if Government provides revenue support which partly or fully insulates generators from electricity price fluctuations, this helps to reduce the risk profile of a project for the generator and therefore reduces the rate of return investors need on their investment compared to projects where no such protection is available.

Modelling conducted for the Electricity Market Reform project, as well as a substantial literature[47] on the subject, provide evidence of the importance of revenue certainty in reducing the cost of low-carbon generation deployment.

Table 4 below sets out a summary of the modelling results that support the consultation, for the cost of capital for different generating technologies under each of the models of FIT. It also assumes that the current RO (which is in the baseline scenario), is effectively a Premium FIT. In practice, a Premium FIT is far less complex than the RO (as discussed below in chapter 2 and below in the section on a low-carbon obligation), and takes away additional uncertainties over revenue.

[47] See, for example, Deutsche Bank "UK Renewable Energy Investment Opportunity: Creating Industries & Jobs" (2010), Stern Review on the Economics of Climate Change (2006), OPTRES "Assessment and Optimisation of Renewable Energy Support Schemes in the European Electricity Market" (2007), European Wind Energy Association "Support Schemes for Renewable Energy" (2005), Ecofys/IEA

Table 4: Reductions in hurdle rates in Redpoint modelling, compared to the baseline

Low carbon support		Baseline	Prem	Fixed	CfD
Hurdle rates (typical utility)					
Onshore wind	Emerging	8.1%	0.0%	-0.3%	-0.3%
Offshore wind (R1/R2)	Mature	10.1%	0.0%	-0.5%	-0.5%
Offshore (R3)	Established	12.1%	0.0%	-0.7%	-0.6%
Biomass	Emerging	12.1%	0.0%	-0.7%	-0.7%
Hurdle rates (independent developer)					
Onshore wind	Emerging	9.1%	0.0%	-1.4%	-1.1%
Offshore wind (R1/R2)	Mature	11.2%	0.0%	-1.2%	-1.2%
Offshore (R3)	Established	13.3%	0.0%	-0.8%	-0.8%
Biomass	Emerging	13.3%	0.0%	-0.8%	-0.8%
Hurdle rates (nuclear developer)					
Nuclear	Emerging	13.2%	-1.0%	-2.0%	-2.0%

Table 5: Treatment of risks under each of the different designs of FIT, compared to the baseline

	Premium FIT	**Contract for Difference**	**Fixed FIT**
Policy Risk (i.e. policy is contract based)	Significantly Reduced	Significantly Reduced	Significantly Reduced
Short-term electricity price risk	No change: rests with generator	No change: rests with generator	Removed
Long-term electricity price risk	No change: rests with generator	Removed	Removed
Offtake risk	No change: rests with generator	No change: rests with generator	Removed
Balancing risk	No change: rests with generator	No change: rests with generator	Removed

39. There are also other costs that need to be considered when examining cost-effectiveness. Key factor are the cost of balancing electricity supply and demand, and the benefits of leaving the investors to decide how much low-carbon generation, and what technology mix, is needed to meet the UK's energy policy objectives. The Government remains committed to a market-based energy policy and is keen to preserve as many of the incentives for efficiency which are provided by exposing generators to competitive pressure in the market as possible. Under a fixed payment scheme, generators are insulated from these signals, because all electricity price risk and offtake risk is transferred to the Government. By contrast a CfD and a premium payment scheme maintain signals for efficiency, by keeping generators exposed to these risks which offers the following advantages:

- it maintains the efficiency signals which exist under the current market arrangements, because generators can benefit from changes in wholesale prices. For example, keeping these signals mean all low-carbon generation has an incentive to carry out maintenance at times when demand and prices are low;

- operators of power stations are well placed to manage short-term electricity price risk because they have access to better market information (than the Government), and a range of tools and strategies to manage the risk of fluctuations in fossil-fuel prices (which feed through to electricity prices). However, long-term electricity price risk is more complex: generators are well placed to manage some elements of this risk (for example gas price risks) but not others which are affected by Government policy decisions, for example the carbon price. Generators also have an incentive – making an economic return on their investments to do this effectively. These incentives have underpinned the approach to energy policy that has delivered low prices for UK consumers since privatisation of the sector

- decisions on whether, when and how much generation to build are determined by the market (i.e. the combined impact of individual investors' decisions). Developers will not build new generation if they either do not believe there is demand from suppliers for more generation, or in attracting a customer, they do not have to offer a price which would make their investment uneconomic. In practice, as low-carbon technologies have different attributes the Government expects investors to bring forward a diversity of technologies in order to provide a hedge against risks such as technology failure or unexpected changes in deployment costs;

40. However, exposing low-carbon generation projects to these risks also has disadvantages. These factors represent the advantages of a fixed payment scheme:

- exposure to these risks may be harder to manage for independent generators with smaller portfolios or for investors in large individual low- carbon generation projects, therefore a fixed payment scheme might have a bigger impact on reducing barriers to entry in the wholesale market; and

- for a premium payment scheme, setting accurate levels of support and avoiding either over or under rewarding low-carbon generators is difficult. It requires a view on future electricity prices as well as a view on future technology costs. If developers take a pessimistic view, and support levels are calculated accordingly, and the future electricity price rose above these expectations it would lead to developers earning more than an economic return on their investment.

41. Under premium FITs, generators will continue to be exposed to long-term electricity price risk, unlike fixed FITs or CfDs. As such, if gas prices were to fall then under premium FITs the prevailing electricity prices paid by consumers would also fall, though the premium payment would remain the same. In comparison there could be implications for the competitiveness of GB industry under fixed payments or CfD, where the costs to consumers would not change. Naturally, these effects could apply in reverse: if gas prices increase then moving to a system where part of the generation capacity was insulated from the impacts of gas price volatility, i.e. under a CfD or fixed payment scheme, would prove to be a benefit to GB industry. If decarbonisation targets remained ambitious in a low fossil-fuel price scenario the Government would need to increase premiums for any new installations. However, levels for support for existing installations would remain unchanged. Whether the overall liabilities are lower than in other models of feed-in tariff,

depends on when the gas price deviates from central expectations and the size of the deviation.

42. There is a risk to over-supply in the generation market under a CfD, because generators (and suppliers) are not exposed to long-term electricity price risk. Where suppliers do not have a generation business, they are not exposed to the same incentives as the integrated utilities to ensure electricity supply and demand remain in balance such that the wholesale electricity price does not collapse. Such suppliers may be willing to sign power purchase agreements with low-carbon generators to supply electricity at market prices. However, neither contracting party would have an incentive to worry about the impact of adding new generation onto the system: if market prices were suppressed because of excess generation, then the supplier benefits from the falling costs for their business, and the generator is insulated from the falling prices by their CfD contract with Government.

43. On balance, when considering both the modelling and the preservation of important efficiency incentives that result from exposure to short-term electricity price risk and offtake risk, the Government considers that a CfD payment scheme appears to present the most cost-effective model of low-carbon revenue support.

Durability

44. For any mechanism to be durable, investors need to believe that it is credible over the long-term. One aspect of credibility is the degree to which the electricity system remains exposed to changes in the external environment, for example to international fossil fuel prices, as is the case with a premium FIT. Different investors would view this exposure in different ways: it can be argued that in being more responsive to changes and avoiding the risk of locking in higher electricity prices in the UK, that the approach is durable, others could argue that because it gives the least certainty over the decarbonisation outcome, that it is less durable than other models for FITs.

45. In the long term, a fixed FITs and CfDs model could become more effective than a premium FIT to support low-carbon generation. Low-carbon generation tends to have low or zero marginal costs of generation; therefore as the mix is increasingly dominated by low-carbon generation, it will become increasingly marginal (i.e. price-setting plant), putting downward pressure on average wholesale prices. This could in some cases start leading to a greater prevalence of negative prices (see box). The Redpoint analysis suggests this could begin to become an issue as we approach 2030. In such scenarios, because the wholesale price is suppressed, and existing investments would be locked in at the original level of premium payments, this uncertainty would be reflected in the cost of capital (and as such the required levels of support) for low-carbon projects under a premium FIT approach.

BOX 6: How wholesale electricity prices can be negative

The fundamental GB wholesale electricity price is set through the Balancing Mechanism in which transmission-connected generation units submit bids and offers at which they would be prepared to reduce or increase their output during each half-hour period. The system operator accepts bids and offers in order to balance generation and demand in real time at minimum cost and the electricity price is set accordingly. (Demand users can also participate, but mostly do not.)

At most times there is a surplus of generation, so the price is set by accepting bids from generators: the price generators are willing to pay to reduce their output. Theoretically this will correspond to the costs that the generator will avoid by turning down or off, which are typically the variable costs of generation including the cost of fuel. Normally these “marginal” generators will be gas or coal fired plant and the system price will be set close to the short-run marginal cost of generation which will be a positive price.

However, when a significant proportion of total generation has very low variable costs of generation, such as nuclear and wind, the short-run marginal cost of generation may be close to zero. Furthermore, if that generation receives payments for each unit of output, such as wind which receives payments under the Renewables Obligation, then the costs that the generator will avoid by turning down or off would include the loss of payments and the bid prices would become negative. Nuclear generators will also tend to bid negative because instead of saving cost, turning off would incur additional costs and risks.

Clearly the system operator will accept bids first from generators prepared to pay to do so, but there may be times when all such bids have been accepted and generators with negative bids have to be accepted to balance the system. At such times the GB wholesale electricity price will be negative.

As the proportion of low-carbon generation in GB increases, there is a possibility that the electricity price will be low or negative for extended periods, particularly when demand is low and the wind is blowing.

This is seen as a problem for generators in general (and low-Carbon generation in particular) that depends on wholesale electricity price for their operating revenue. However, it is a benefit for consumers able to vary their time of consumption and for all forms of energy storage, such as pumped storage hydro and electric vehicles with batteries.

One way to limit such effects would be to provide price support based on availability to generate rather than actual output generated, or by otherwise designing a support scheme to ensure that support is not payable when prices are negative.

46. On balance, the Government considers all of the options for a FIT could be durable, although in the long-run recognises the problems that arise under a premium payment scheme where there is a continued focus on marginal pricing in the wholesale electricity market when the price is set by low marginal cost plant (i.e. low-carbon generation).

47. A key factor in setting the levels of support under a feed-in tariff will be the need to avoid incentivising particular technologies beyond the point at which they are sustainable in respect of their environmental impact or which locks us into a mix of technologies which is not sustainable in the longer term.

Practicality

48. A premium FIT is the closest of the different models for a feed-in tariff to the system currently in operation in the market. The Renewables Obligation (RO) has similar characteristics to a premium FIT in that the RO provides a broadly fixed revenue to generators in addition to revenues from electricity sales[48]. Introducing any new mechanism in the market will unavoidably cause a hiatus in investment. However, as an incremental change to the market, the risk of an investment hiatus is lower with a premium payments system than for other models of FIT. The relative simplicity of a premium payments scheme could lead to fewer unintended consequences and less opportunity for gaming of the system.

49. On balance, the Government concludes that while a premium payments scheme would be easiest to implement, there are additional benefits of a contract for difference scheme in terms of cost-effectiveness which could outweigh the additional complexities of such a scheme.

Box 7: FITs with CfD in the Netherlands and Denmark

Since 2008, the Netherlands has used a FIT very similar to a FIT with CfD to incentivise renewable technologies (called a “sliding premium” because the size of the premium is related to the wholesale price). Generators have to sell their electricity (either into the wholesale market or in bilateral contracts) and then an energy agency pays them a top-up payment (differentiated by technology) up to the tariff level.

The tariff is decided by the government. Contracts are signed by the energy agency for 15 years. The reference price is the average annual spot market price. The top-up is paid out monthly to facilitate cash flow for smaller generators. It is in effect a one-way CfD in that if the electricity price goes above the tariff then the generator keeps all the upside.

Denmark have since 2005 operated a feed-in tariff for offshore wind which is also very similar to a CfD model. For major offshore wind farms the required support is set by means of a tender procedure. In tenders determined so far the following contracts have been agreed with the Danish Energy Agency:

- Horns Rev II 200 MW 6p/kWh 50,000 full load hours;
- Rødsand II 200 MW 7p/kWh 50,000 full load hours; and

[48] The Government’s principles for transitioning the RO to the new market arrangements is discussed later in this document

- Anholt 400 MW 12p/kWh for 20 TWh.

By way of example, the key contract terms for the Anholt contract are as follows:

- For electricity produced a price supplement shall be paid, calculated hour by hour as the difference between the offered price per kWh and the spot price for electricity in the relevant area.
- The total price supplement for an hour shall be the product of the price supplement and the metered production for the same hour.
- A price supplement shall not be paid for production during hours in which the spot price is not positive. This, however, shall only apply for a maximum of 300 hours per year.
- The owner of the wind turbine shall be responsible for sales of production on the electricity market and for paying the costs of this.
- No allowances shall be paid for balancing costs for electricity from the wind turbines.
- Payments shall be for a maximum of 20 years and a maximum of 20 TWh.

Coherence

50. The Government anticipates that all three types of a FIT could be combined with a capacity mechanism, and emissions performance standard and the carbon price support mechanism. However, there are differences in the interactions between different designs of a FIT and the carbon price support mechanism, which affect how well they fit together. Based on the modelling and wider analysis for this project, the Government believes that although a premium FIT can work well with the carbon price support mechanism, there is an issue involving under/over-rewarding low carbon generation. This issue, which would need to be resolved if both were included in a package of reforms, is explained in more detail below. By contrast, a CfD mitigates the risk and therefore the Government believes that it is more compatible with carbon price support.

51. A premium FIT combines well with the carbon price support to have a direct impact on influencing investment decisions. Both measures are designed to change the electricity price faced by low-carbon generations to reflect the Government's policy objectives. The carbon price support mechanism puts a more stable price on carbon to drive emissions and the premium FIT provides an additional uplift in electricity prices to reflect the higher cost and risk profile

of low-carbon generation in order to support investment as the scale and pace required to meet the Government's targets.

52. However, there are risks in combining the instruments together: once the level of support is set under the premium FIT, it does not change in response to changes in the electricity price. This means that if the Government changed the carbon price support mechanism to increase the target carbon price, it would push up the electricity price, but existing generators would continue to receive the same level of support under the premium FIT. This would enable them to earn a more than economic return on their investment, unfairly, at the expense of the consumer. If the electricity price were lower than expected, for example because the Government reduced the target carbon price in the carbon price support mechanism, generators may be under-rewarded. Government would find it difficult to retrospectively adjust the premium FIT rates to respond to either under or over-rewarding investment – without significantly increasing uncertainty for investors. Leaving generators exposed to this risk would mean that investors would apply a higher cost of capital under the premium FIT compared to the CfD.

53. Combining the carbon price support mechanism with a fixed FIT, or a CfD eliminates this problem. Under a CfD, the support level is dynamic. It changes in response to the average wholesale electricity price, so that the combined revenues from electricity sales and support under the CfD equals the agreed strike price in the CfD. In practice, this means that the Government could change its target price through the carbon price support mechanism without affecting the overall returns made by low-carbon generators. The compatability – and main benefit – comes from this automatic revenue stabilisation factor which prevents over- or under-reward for generators. For this reason the CfD can be argued to work better with the carbon price support mechanism.

54. For a fixed FIT, the wholesale electricity price has no bearing on returns made by generators so there is no policy interaction. However, there remain concerns about how a fixed FIT would interact with the wholesale market – therefore a package of reforms with this option included would also be less coherent.

55. For a more detailed description of the lead package for reform and how the different policies interact, see chapter 5.

Public Finances

56. In the short term, the low-carbon transition will require investment in more expensive forms of electricity generation; however, in the medium to long-term, the Government expects the costs of the transition should be minimised as a result of early action. This additional cost will need to be paid for by consumers – both domestic and business; hence the Government's focus on cost-effectiveness as a key criterion for assessing policy options. However, in addition, the Office of National Statistics is likely to consider all of the FIT

options to be classified as tax and spend[49] (as the RO currently is), therefore the specific public finance implications also need to be considered.

57. Based on the modelling undertaken to date, the level of public support is expected to be slightly higher under the premium FIT, as set out in table 3 above. However, support under the premium FIT would be significantly more predictable and easy to manage. By contrast, support under the fixed FIT and CfD schemes would vary according to changes in the electricity price, a factor which the Government is not well placed to forecast or to manage.

Low-carbon obligation

58. A low-carbon Obligation is an alternative mechanism to support the electricity price for low-carbon generators. It would require suppliers to source a certain percentage of electricity from particular sources of low-carbon generation, or to pay a buy-out price, the proceeds of which are recycled to those suppliers who have presented certificates in proportion to their share of total renewable energy supplied. Low-carbon generators are able to sell "certificates", which suppliers are required to present on an annual basis to prove their compliance with the Obligation, as well as their electricity. This enables them to earn a premium in addition to the market electricity price..

59. This would, in effect, be an extension of the Renewables Obligation to nuclear and CCS: the Government expects that a banded approach would continue to be required in order to ensure delivery of the EU 2020 renewable target (reflecting the higher costs of renewables compared with other forms of low-carbon generation such as nuclear).

60. In practice, the impacts of a low-carbon obligation would be similar to a premium FIT, because it provides additional revenues on top of revenues from the sale of electricity. As such, it is likely to have similar advantages and disadvantages as discussed earlier in this document. However, the Government considers it would be a relatively unattractive alternative to a premium payment scheme because it shares some of the same characteristics that cause concerns with the RO:

- The complexity of the instrument largely restricts its attractiveness to larger energy companies and it would be unlikely to support any new entrants to the market; and

- Calculating the Obligation is complex and can result in revenue uncertainty and potential over or under payment.

61. ROC prices have a floor (the buy-out price[50]), which guarantees a certain level of stability for investors. However, due to the way the Obligation is set at a

[49] The tax element is based on the assumption that the costs of the support are recovered through electricity bills, in the same way as the Renewables Obligation is today. The Government has a choice whether to fund any new mechanisms through general taxation, or to introduce a specific levy

higher level than expected generation, the value of a ROC is typically higher than the floor price, and this level can vary. Due to this variability, not all of this additional value is included in the calculation of finance for renewable projects. Thus the additional value does not necessarily result in higher levels of renewable investment. A different instrument with a fixed level of payment (a premium FIT) could deliver the same level of deployment more cost-effectively.

62. The RO mechanism may act as a deterrent to new investors from outside the UK who are typically more familiar with FIT models. This may be particularly important given the need to attract new sources of finance to the sector.

63. Including projects with a large generating capacity, such as a new nuclear power station or full-scale CCS power station, in an obligation based scheme can be problematic. In order to prevent the price of a certificate crashing, or rising such that it provides more than economic return, the central body setting the obligation level will need to ensure that the level of the obligation rises in line with the commissioning of new projects. It can be difficult to predict exactly when a new station will be commissioned – the effects of this are more profound with larger capacity projects.

64. The Government recognises that as an incremental measure, this would be the most straightforward low-carbon electricity price support mechanism to introduce of those considered in this project. This would mean lowest risks of unintended consequences and investment hiatus. However, on balance because there is a similar, but more cost-effective mechanism (the premium FIT), the Government does not consider this an attractive option for reform.

65. Another benefit of a FIT over a low-carbon obligation is that the investor gets certainty when they sign the contract about the level of support they would receive, rather than the support level being set after construction, once the installation is built and connected to the grid, i.e. with ROCs generators are exposed to the policy risk that the level of support changes in between an investment decision and the project being accredited under a obligation based scheme.

Regulated Asset Base (RAB)

66. The regulatory asset base (RAB) model is used by regulators as a mechanism for providing a credible commitment to the recovery of the sunk costs associated with capital investment by regulated monopolies. In the electricity sector, a RAB model already applies to the development and maintenance of transmission and distribution networks. Network licensees are allowed to add efficiently incurred capital expenditure to their RAB and to make a return on that investment in line with their average cost of capital through setting tariffs

[50] Suppliers can choose whether to buy-out of their obligation or present Renewable Obligation Certificates (ROCs). Provided the obligation exceeds the level of renewable generation on the system, then the ROC price would never fall below the buy-out price.

for the use of their network. For these companies, Ofgem will periodically approve a level of expenditure and calculate and associated cost for the work and then set a price cap that network operators are allowed to charge to fund their RAB. This commitment on behalf of the regulator in effect means a transfer of risk from the developer to the consumer.

67. It is possible to extend this approach to low-carbon generation. Extending the RAB model to assets and/or sectors which are not currently the subject of economic regulation may create a similarly lower risk environment to which investors are attracted to commit funds and may result in a lower cost of capital. For low-carbon generation an investment could be allowed into a company's RAB at an agreed cost with a tariff paid at a level adjusted periodically by a regulator to allow an agreed rate of return subject to incentives for availability and efficiency of operation. In effect, guaranteeing a regulated return would mean transferring the following risks away from the generator to the consumer: offtake risk, electricity price risk (both short- and long-term) and unlike a feed-in tariff, also construction risk. Construction risk is transferred because the RAB is adjusted periodically, to reflect changes in construction costs and other factors.

68. In this respect, the RAB would share many of the same advantages and disadvantages as for fixed FITs:

- **Advantages:** there is a significant evidence base that suggests costs of capital for regulated businesses are lower than for unregulated businesses[51] – as such a RAB could lead to a reduction in cost of capital and as such the support costs needed to meet the UK's decarbonisation objectives.

- **Disadvantages:** significant loss of market efficiency signals because generators are insulated from all risks. RABs are well suited to markets with natural monopolies, such as the electricity networks, where these incentives do not exist. The Government expects the loss of these incentive is likely to outweigh the benefits from lower costs of capital. A RAB model would also require Government to centrally determine the level and mix of low-carbon technologies in the generating mix.

69. However, it also transfers a construction risk, which generators are better suited to manage, to the consumer. It would represent the most fundamental change to the current arrangements of all the options; making such a radical change would be high risk. Moving to a RAB system would require the Government to sacrifice all market benefits and competitive pressures for greater efficiency, optimal operation and innovation that could be retained under other options considered as part of this project. The generation sector – where competition is viable and a key feature of the current market – is different to the natural monopoly market for the provision of transmission and distribution networks. As such, the Government does not consider this an attractive option for reform.

[51] National Infrastructure Plan, HMT 2010
(http://www.hm- treasury.gov.uk/d/nationalinsfrastructureplan251010. pdf)

Conclusion on low-carbon generation revenue support

70. In summary, the Government's lead option for low-carbon revenue support is a feed-in tariff with a contract for difference on the electricity price. All of the designs for a feed-in tariff have advantages and disadvantages, but the balance between these is most positive for a CfD.

71. A fixed payment scheme would give greater confidence than a premium payment scheme of meeting our decarbonisation targets even in scenarios with lower gas prices or higher electricity demand. The fixed FIT would keep costs to consumers lower through enabling a lower cost of capital for developers. It would also be more likely to attract new entrants because of the revenue certainty it provides. However, this comes at the expense of losing the exposure of generators to all the market incentives to operate efficiently which exist in the current system. A fixed payment scheme could also have a negative impact on security of supply because it removes the market disciplining incentives to dispatch efficiently that the electricity price signal provides. Therefore it would increase balancing costs. In addition it is a significant change to the electricity market (for example it might require an electricity pool to be introduced) and therefore it might cause an investment hiatus in renewables.

72. A premium payment scheme would maintain these important market price signals which contributes both to cost-effectiveness and the security of the electricity system. It would give less certainty of meeting the Government's long-term, low-carbon targets, but it could be implemented relatively easily therefore minimising the risk of any delays to planned investment in renewables. However, the modelling indicates it would be somewhat more costly to consumers because it has a smaller impact on the cost of capital for investors. The public finance impacts are more predictable under premium FIT and therefore easier to manage, but the overall level is likely to be slightly higher. In addition, we would need to resolve any issues caused by the interaction between the carbon price support and a premium FIT when developing this model further.

73. A FIT with CfD would combine the best features of a fixed FIT (the high confidence of meeting our targets, low cost of capital and therefore lower costs to consumers, as well as greater ability to attract new entrants) with the best features of a premium FIT (maintenance of most market price signals and the efficient behaviour this incentivises). It therefore scores well on all three of the government's key objectives (decarbonisation, renewables, security of supply and affordability). It also scores well on the criteria of cost-effectiveness and durability. However, it is more of a change to the electricity market than premium FITs so scores slightly less well on practicality. The Government has set out in chapter 6, early thoughts on how a CfD scheme could be implemented and how to ensure a smooth transition and avoid an investment hiatus in renewables.

74. There are issues which need further consideration and which the Government is keen to address through this consultation, for example there are a number of design and implementation issues that need further consideration. The Government is also mindful of the difference in the impacts on public finance under the different models. Therefore, the Government also considers a premium FIT model as a credible alternative that would enable the electricity sector to meet its decarbonisation and renewable objectives.

75. A low-carbon obligation would have more of the disadvantages of a premium FIT but fewer of the advantages. And a RAB would have more of the disadvantages of a fixed FIT with fewer of the advantages. As such, the Government is not minded to consider these options further in the next stage of this project.

Question 3: Do you agree with the Government's assessment of the pros and cons of each of the models of feed-in tariff (FIT)*?*

Question 4: Do you agree with the Government's preferred policy of introducing a contract for difference based feed-in tariff (FIT with CfD)?

Question 5: What do you see as the advantages and disadvantages of transferring different risks from the generator or the supplier to the Government? In particular, what are the implications of removing the (long-term) electricity price risk from generators under the CfD model?

Question 6: What are the efficient operational decisions that the price signal incentivises? How important are these for the market to function properly? How would they be affected by the proposed policy?

Question 7: Do you agree with the Government's assessment of the impact of the different models of FITs on the cost of capital for low-carbon generators?

Question 8: What impact do you think the different models of FITs will have on the availability of finance for low-carbon electricity generation investments from both new investors and existing the investor base?

Question 9: What impact do you think the different models of FITs will have on different types of generators (vertically integrated utilities, existing independent gas, wind or biomass generators and new entrant generators)? How would the different models impact on contract negotiations/relationships with electricity suppliers?

Question 10: How important do you think greater liquidity in the wholesale market is to the effective operation of the FIT with CfD model? What reference price or index should be used?

Question 11: Should the FIT be paid on availability or output?

Emissions Performance Standard

76. An Emissions Performance Standard (EPS) is a regulatory limit on the amount of carbon dioxide released into the atmosphere from a source (or sources) of electricity generation. The Coalition Agreement envisages an EPS playing a role in a package of reforms to prevent the construction and operation of new unabated coal-fired power stations, which represent the most carbon-intensive form of electricity generation. This does not mean that new coal-fired power stations have no part to play in providing electricity in the future, but it does mean that action must be taken to reduce their emissions if they are to play a role.

77. A large proportion of the UK's current generation mix comes from coal, but this needs to decrease over time as other, low-carbon sources of generation increase. Having coal-fired power stations in the electricity mix helps to increase diversity and prevents an over-reliance on a single technology. It is a flexible fuel source that can provide backup generation, which will be increasingly important with more intermittent renewables on the system. Coal is also available from a wide range of different geographical locations and in different places to existing gas reserves. Therefore, having coal in the mix also contributes to the geographical diversity of our energy supplies, which makes a significant contribution to the security of the system. However, the Government believes that to achieve its goals for decarbonisation new coal plant should not continue to be built in the UK unabated. For these reasons the Coalition Agreement also commits the Government to public sector investment in four CCS demonstration projects, as this technology is critical to allowing fossil fuel power stations to operate in a carbon constrained world, and public spending has already been allocated to fund the first commercial-scale CCS plant.

78. The objective of the EPS is to ensure that while coal continues to make an important contribution to security of supply, it does so in a manner consistent with the UK's decarbonisation objectives. It would act as a regulatory backstop, alongside a system of rewards and incentives, the building blocks of which are considered in this consultation (carbon price support, feed-in tariffs and capacity mechanisms). The EPS will also provide further clarity on the regulatory environment for coal-fired power stations, building on the Government's current policy[52] that developers must demonstrate CCS on a proportion of the power station's capacity and be carbon capture ready (CCR) on the rest.

Box 8: Summary of Emission Performance Standard Proposals

The Government proposes to introduce an emissions performance standard to complement other market reforms. As a first step, this will build on the requirement to demonstrate CCS as part of the consenting process, by

[52] Subject to ongoing consultation in the case of the revised draft National Policy Statements issued by DECC under the Planning Act – see www.energynpsconsultation.decc.gov.uk.

preventing investment in new unabated coal-fired power stations and their operation without an appropriate level of CO_2 abatement. It is intended that the EPS be set in a way that does not restrict the CCS Demonstration Programme, but provides a clear regulatory signal on the need to abate emissions from coal-fired power stations. The Government also proposes to review the EPS as part of the wider decarbonisation review required under the Energy Act 2010 (section 5), to consider the role of an EPS in driving further use of CCS.

The design principles include:

- application to individual power stations;
- setting an annual limit on the total amount of CO_2 permitted per unit of installed capacity;
- application to new power stations only, and with an ongoing principle of grandfathering, i.e. the level of the EPS on the date of consent of a new power station will apply for the economic life of the installation;
- consistency with a CCS Demonstration Programme covering the full range of approaches to carbon capture.

The Government is also seeking views on two options on the level of the EPS:

- Set at a level equivalent to 600g CO_2/kWh, consistent with demonstrating post-combustion CCS on a new, supercritical coal-fired power station;

Set at a level equivalent to 450g CO_2/kWh, with specific exemptions for plant forming part of the UK's CCS Demonstration Programme or benefiting from European funding for commercial scale CCS projects.

Setting the level of the EPS

79. The Government believes that the objective in setting the level of the EPS should be to identify a level that provides an effective regulatory backstop to control emissions from new coal-fired power stations, whilst supporting the demonstration of the full range of approaches to CCS in the UK. In order to achieve this, the Government is presenting two options for consultation.

80. Both of these options are based on an EPS set as an annual limit of carbon dioxide, because the Government considers that this will offer the flexibility necessary to operate plant equipped with CCS, whilst also providing a clear requirement to reduce emissions. The Government also considers that applying it to individual plant offers clarity over regulatory requirements that cannot be offered through an EPS applied to a suite of plant.

Option 1

81. An EPS as an annual limit on the amount of CO_2 plant can emit, equivalent to 600gCO_2/KWh for plant operating at baseload.

82. This level is consistent with demonstrating CCS on a new, supercritical coal-fired power station, which are typically sized at around 1600MW (gross). It would allow stations to demonstrate CCS on around a quarter of their capacity (300MW net or 400MW gross[53]), consistent with the draft National Policy Statements. The Government also considers that this would be consistent with the CCS Demonstration Programme, which is predicated on the Government funding four commercial-scale demonstrations across a range of technologies.

Option 2

83. An EPS as an annual limit on the amount of CO_2 a plant can emit equivalent to 450gCO_2/kWh for plant operating at baseload. Plant forming part of the UK's CCS Demonstration Programme or benefiting from European funding for commercial-scale CCS would be given exemptions.

84. This option would provide a stronger signal on the need for decarbonisation, requiring new plant to meet the tighter standard. For example, it would require a new, supercritical coal plant, sized at around 1600MW (gross) to use CCS on around 700MW (gross) of its capacity, around 40%. However, in order not to constrain demonstration of the full range of approaches to CCS, exemptions are proposed for plant forming part of the UK's CCS Demonstration Programme or benefiting from European funding for commercial-scale CCS projects.

85. The Government considers that both of these options will allow demonstration of the full range of approaches to CCS. However, it is considered that requiring plant forming part of the Demonstration Programme to meet an EPS lower than 600gCO_2/KWh would have a negative impact on the development of the technology. This is because it would either effectively rule out the demonstration of CCS on new post-combustion coal power stations, as it would require more than 300MW net capacity to be abated, or require additional public expenditure to fund a larger demonstration. Demonstrating the technology at a larger scale would increase costs and represent poor value for money since the majority of learning can be derived capturing the carbon dioxide from 300-400MW. Alternatively, meeting a lower annual limit EPS by operating the power station at a reduced load factor, or constraining the overall size of the plant, is unlikely to be acceptable to potential investors; this would reduce operating revenue and deter investors from engaging with CCS demonstration on supercritical coal.

86. CCS is an immature technology that has never been tested at scale on a power generation project. The Government identified £1bn in the 2010

[53] Net refers to the capacity after the electrical output from the power station needed to run the CCS chain has been used.

Spending Review for the first of these projects. Imposing additional costs on the Demonstration Programme would create affordability concerns, but yield limited additional benefits. Supercritical coal plant equipped with CCS could be important in an electricity mix in providing flexibility with a high proportion of intermittent renewable energy sources. However, by not demonstrating CCS on this type of plant, their flexibility and load following capability when equipped with CCS would remain untested. Also, given that CCS technology has not been demonstrated at commercial-scale on a power station, we do not know which of the various approaches to carbon capture will be the most effective. It is therefore considered important to ensure that the UK's CCS Demonstration Programme is open to the full range of technologies, as this will provide greater choice for the market when it comes to the deployment of CCS.

Application on new coal-fired power stations

87. The Government is proposing not to apply an EPS retrospectively to existing plant. Making retrospective changes to existing power stations can have significant economic impacts on the operator. For example, if an obligation to fit CCS to existing coal-fired power stations were imposed, it is likely that developers would choose to close their power stations because the alternative – to fit a costly and untested technology - is unattractive.

88. There would be direct security of supply risks associated with a retrospective EPS. Around 8GW of existing coal plant will be closing by 2016 as a result of EU environmental legislation (the Large Combustion Plant Directive (LCPD)). The remaining coal plant are anticipated to provide a means of back-up generation, which will minimise the need for additional build of new CCGT plant in the 2020s. Modelling indicates that some existing coal plant is expected to continue operating under the Industrial Emissions Directive (IED) but at very low load factors, so the overall carbon emissions would be low. An EPS, even set as an annual limit, could increase regulatory risk, creating an incentive for such plant to opt-out rather than make the investments needed to meet IED emission standards, and close by the mid 2020s. Closing more existing coal plant than will already occur under the IED and LCPD would increase the security of supply risks.

89. Such a policy would also have a significant negative impact on the attractiveness of the UK as a place for investment in the electricity sector. One of the unavoidable risks in the energy sector is regulatory: at any point during the operating life of a power station, Government may change the regulatory environment and undermine the economics of a power station, forcing early closure with implications for the investor's finances. However investors will gauge the overall regulatory risk in the UK, based on Government behaviour and a series of discrete, individual decisions. Where investors perceive actions are taken against one set of generators, they will become increasingly nervous and might choose not to make new investments in the UK because of their perceptions of the regulatory risk. For example, decisions taken by the Spanish Government over summer 2010 to retrospectively reduce levels of

renewable subsidies has affected levels of investor confidence in Spain[54] and indeed across other European countries.

90. Another way of helping to ensure continued investor confidence in the UK energy sector would be to apply the principle of grandfathering, which is widely used in regulatory regimes, including the Renewables Obligation. In its simplest form, the principle of grandfathering, when applied to an EPS would mean that the level of the EPS in place at the point that a power station is consented remains the level which is relevant for the economic life of that power station, i.e. if Government decided to lower the level in the future, say to reflect advances in CCS technology, the EPS would only be at the lower level for plant consented after the date of that decision. Without such protection in place, the regulatory risk around investing in any new fossil-fuel power stations might prevent any new flexible plant being built, creating a risk to security of supply. The Government's initial view is, therefore, that the EPS be grandfathered, for a period linked to the period of time investors would expect to see a return on their capital investment.

91. However, the Government is also aiming to avoid creating incentives to extend the lifetime of existing plant significantly, at the expense of building new, modern power stations, which are likely to be more efficient, including those fitted with CCS technologies. It is, therefore, proposed that the EPS should be applied to existing plant where they undergo a significant life extension or upgrade (excluding plant which install Selective Catalytic Reduction, the equipment needed to meet the IED emission standards, or plant that reduce their carbon emissions by retrofitting CCS to a proportion of their capacity), requiring them to meet the same emissions standards applicable to new plant at the time of the upgrade. The Government is aware that there are a number of factors which could determine whether a plant is undergoing a significant life extension or upgrade, and is seeking views on how to best define this for the purposes of the EPS.

Reviewing the EPS

92. Given the level of technological maturity, there remains considerable uncertainty over the cost of demonstrating CCS successfully at commercial scale. These uncertainties mean the private sector is unwilling to shoulder the financial risk of demonstration projects until the technology is further developed. It is for this reason that the Government has committed to continuing public sector investment in CCS for 4 demonstration projects.

93. The Government believes that, should it be needed, there will be future opportunities to put in place further regulation for new plant to require increased use of CCS, or otherwise limit their emissions, but that a better time to do this, will be once the Government has a better understanding of the commercial and technical viability of CCS technology. There is already a statutory requirement under the Energy Act 2010 for the Government to report

[54] According to Ernst and Young, since 2009, Spain has dropped from fifth most attractive country for investments in renewable generation to eighth, following these changes. http://www.ey.com/GL/en/Industries/Oil---Gas/Oil_Gas_Renewable_Energy_Attractiveness-Indices

on progress in decarbonising the GB electricity system and on the development and use of CCS. The first reporting period ends in 2011, with further periods running on a 3-year basis starting in 2012[55]. The Government proposes that these progress reports will incorporate a review of the role of a tighter EPS in driving further use of CCS, linked to the status of the technology. This will enable the Government to make a more informed assessment of whether additional measures or regulation are necessary, balanced with objectives on decarbonisation, energy security and consumer costs.

94. The Government is clear that unabated gas continues to have an important role to play in ensuring security of supply over the next decade. Over the longer term the UK will need gas plant to be equipped with CCS if we are to meet the Government's decarbonisation objectives. While the proposed EPS would be technology neutral, it is intended that the level will only affect coal plant, and the Government does not, at this point, consider it appropriate to specify an EPS that would affect gas plant for the following reasons:

- other reform measures will provide an effective means to decarbonise the electricity sector: the modelling suggests some new build of gas-fired power stations, and those unabated fossil plant remaining on the system will account for a decreasing proportion of the electricity mix, running at increasingly low-load factors, increasingly providing a role as back up generation; and

- an EPS for gas could introduce a number of unnecessary risks: signalling that new plant will be required to be fitted with CCS from a date in the future runs the risk of stimulating a 'dash for gas' prior to that date, or else, by creating regulatory uncertainty, could create a significant hiatus in the investment we will need this decade, putting the UK's security of supply at risk. This is particularly relevant whilst CCS remains unproven for commercial scale electricity generation.

- As with other technologies, the Government's preference is to 'grandfather' the EPS at the point of consent for new gas-fired power stations, thereby giving investors certainty that their plant will not, during their economic lifetime, be subject to tighter standards. In practice, this would mean that gas plant consented while the EPS remains at a level that does not affect their operation will not be subject to a tighter level during their economic life.

Implications for electricity market objectives

95. The Government considers that an EPS targeted on unabated coal-fired power stations can contribute to achieving the UK's decarbonisation objectives. It provides longer-term certainty to investors over regulatory measures related to coal-fired power stations. In addition, it would provide a regulatory backstop to prevent the most polluting plant from entering the system unabated, whilst also

[55] The reports must be laid before parliament within 1 years after the end of the reporting period (s5(5)).

allowing for demonstration of all CCS technologies. The wider measures set out in this consultation will be the key drivers in terms of decarbonisation.

96. At the levels proposed for consultation, the EPS is unlikely to have any significant negative impact on capacity margins and security of supply. However, to insure against unforeseen risks, the Government is proposing to build in flexibilities to mitigate the risks of short-term or longer-term shortfalls in electricity supply:

- an EPS set as an annual limit will allow for plant to operate unconstrained when demand so requires, provided it compensates for the emissions at other times, through, for example, reduced running hours. This will also enable peaking plant (e.g. OGCT) to operate. The Government does not consider this will have a material impact on overall emissions from the electricity sector because such peaking plant would be operating very short period of time, so the annual emissions would be negligible[56]; and

- exceptions to the EPS where there are short-term or longer-term energy supply emergencies. For example, in order to safeguard security of supply such an exemption would allow coal plant, under tightly defined circumstances, to turn off their CCS equipment at times of exceptional demand and thus be able to output additional electricity to the grid, or it would allow the plant to operate at a higher output (or load factor) than the constraints imposed on its operation by an EPS.

97. The Government does not believe these flexibilities will affect the ability of a targeted EPS to guard against the risk of investment in unabated coal-fired power stations. As well as the flexibilities above, the EPS needs to be designed to support the burning and co-firing of an appropriate level of biomass. One option would be to 'zero rate,' or otherwise differentiate, the emissions from the biomass fuel when calculating plant carbon dioxide emissions. The Government is seeking views on the considerations that should be taken into account.

Performance against criteria

98. The proposed options for the EPS are consistent with demonstrating CCS on around 400MW (gross) of output of a new supercritical power station, and therefore the Government does not expect any costs to the economy in addition to the costs of the CCS Demonstration Programme to be created as a result of implementing the targeted EPS.

99. The main issue for durability is investor confidence that the EPS will not constrain the operation of their power plant in the future, so as to limit investment in new plant equipped with CCS. While the method of implementation will be designed to provide certainty, there will always exist some uncertainty on future regulation. The Government will be playing

[56] See EMR Impact Assessment.

particularly close attention to this as the method for implementing the EPS is developed.

100. The Government believes that the EPS can be implemented without excessive impact on current processes. Monitoring and enforcing the EPS would seem to be closely related to the administration of the EU ETS in the UK. When implementing the EPS, the Government will be looking to keep any additional regulatory burden on operators or public bodies to a minimum.

Alternative Options

101. We have considered an alternative option of an EPS designed as the sole mechanism for the UK to meet its decarbonisation objectives. This, in principle, could be achieved by effectively imposing a running hours limit on all fossil-fuel power stations, both new and existing. This limit would be then progressively tightened such that by 2030 only fossil-fuel power stations equipped with CCS would be able to operate as baseload. The general effect of this would be to increase the electricity price to a level where it was economic for generators to invest in low-carbon generation, which typically have higher costs (and higher risks). It would create significant security of supply risks by driving early closure of existing plant and preventing new investments in flexible generation plant.

102. However, the Government does not believe that an EPS could be implemented to deliver the UK's emissions targets without a system of incentives to support investment in low-carbon generation. Such an EPS is unlikely to be viewed as a credible intervention by investors. Emissions limits would be relatively straightforward for Government to change, and the Government expects investors would discount any long-term commitment to the policy, given the risks to security of supply. Should the Government relax the policy to allow fossil-fuel power stations to operate unabated, this would undermine the economics of a range of existing low-carbon plant, by suppressing the electricity price. As such, the risk of future revenues is expected to be too great for the policy to be credible with investors.

103. It would create significant security of supply risks: such an EPS would make it unattractive to build the flexible back-up generation needed to support a low-carbon mix (which is predominantly gas-fired power stations). Investors would have no certainty over the economics of power station investments because Government would explicitly set out as a policy intention to make retrospective changes to the number of hours a power station is allowed to operate. There are other security of supply risks: namely preventing the construction of fossil-fuel power stations in the UK will not automatically mean that investment in low-carbon generation will replace it, potentially leaving the UK with insufficient generation to meet future demand. The UK is competing internationally for investment capital and developers may choose to invest in other markets with lower regulatory risks.

104. In addition, the Government considers that such an approach has a number of other unattractive implications including an NPV of -£7.7bn.

Question 12: Do you agree with the Government's assessment of the impact of an emission performance standard on the decarbonisation of the electricity sector and on security of supply risk?

Question 13: Which option do you consider most appropriate for the level of the EPS? What considerations should the Government take into account in designing derogations for projects forming part of the UK or EU demonstration programme?

Question 14: Do you agree that the EPS should be aimed at new plant, and 'grandfathered' at the point of consent? How should the Government determine the economic life of a power station for the purposes of grandfathering?

Question 15: Do you agree that the EPS should be extended to cover existing plant in the event they undergo significant life extensions or upgrades? How could the Government implement such an approach in practice?

Question 16: Do you agree with the proposed review of the EPS, incorporated into the progress reports required under the Energy Act 2010?

Question 17: How should biomass be treated for the purpose of meeting the EPS? What additional considerations should the government take into account?

Question 18: Do you agree the principle of exceptions to the EPS in the event of long-term or short-term energy shortfalls?

CHAPTER 4 – security of supply and market operation reforms

Chapter Summary:

The Coalition Agreement made a commitment to introduce a "security of supply guarantee". As part of this project, the Government has considered the contribution that incremental reforms to the current market could make to reducing future security of supply risks. The Government has also considered whether an explicit responsibility for maintaining an adequate capacity margin should be introduced. The capacity margin would then be achieved through a capacity mechanism.

The Government sees as vital the work started by Ofgem and National Grid to improve arrangements for the balancing of the system and to increase levels of liquidity in the wholesale market. These will provide important benefits to the wider operation of the GB electricity market, including improving signals for investment in new capacity, and therefore security of supply.

However, because of the increasing risks to security of supply arising from the transition to low-carbon generation, the Government is consulting on introducing a capacity mechanism to explicitly reward the provision of capacity (as opposed to only the energy from electricity generation). Such a mechanism would also be designed to reward demand-side response, to encourage the development of energy efficiency and other "smart" technologies.

The Government is minded to introduce a targeted mechanism, where an obligation would be placed on a central body to maintain a set capacity margin. This body would make an assessment of the level of spare capacity that will be provided through the energy market and then will run tenders for any additional capacity needed to make up the shortfall between the level of capacity provided by the market and the centrally determined margin. They would seek to minimise market distortion in its operation.

1. The measures set out in chapter 3 will help ensure our decarbonisation objectives are met. They will also contribute to security of supply through incentivising new generation, although they alone will not be sufficient to address all of the security of supply concerns identified in chapter 2 and through facilitating a transition to low-carbon generation could exacerbate some of the security of supply risks. This chapter therefore sets out the measures considered to improve security of supply specifically and wider market operation more generally. It firstly considers ways in which the current market arrangements could be improved. It then considers how the current market framework could be modified by the introduction of a capacity mechanism.

2. Under improving current market arrangements, the chapter considers:

- reforms to the balancing arrangements (i.e. the way that the System Operator ensures electricity supplied equals demand in a real-time basis) to improve security of supply and reduce balancing costs;

- actions to improve liquidity, i.e. increase trading in the wholesale market, which will improve security of supply, increase competition in the market and reduce barriers to entry. Liquidity is also discussed in more detail in chapter 5; and

- actions to increase the involvement of the demand side which can increase security of supply, increase competition, reduce costs and reduce emissions.

3. In addition to such reforms, a responsibility for maintaining capacity margins could be introduced to improve security of supply. The capacity mechanism section considers key design choices in implementing a mechanism that enables a desired capacity margin to be achieved:

- whether price is set in a decentralised bilateral market or by a central body;

- whether price or volume is set;

- whether the mechanism pays all, or only some resource[57].

Improving the operation of the current market

4. In the current market arrangements decisions on how much capacity is needed are taken by those parties investing in new power stations. Potential investors will consider the outlook for supply and demand for electricity and the forward price curve. Based on an assessment of these factors, they decide on whether investing in new capacity would deliver an economic return. For such a system to operate effectively, clear price signals are necessary to provide the incentives to invest. Chapter 2 explained that in the current market, these signals are not as effective as they might be.

Reforms to the balancing arrangements

5. Responsibility for ensuring the electricity system remains in balance lies with National Grid, the system operator. They incur costs in increasing supply or reducing demand to balance the system and then recover these costs through "cash out payments" paid by those parties out of balance, i.e. those who provide or use a different amount of electricity than they promised.

[57] Capacity mechanisms can be designed so that both supply side (generating capacity) and demand side (reductions in demand or Demand Side Response) can be rewarded. Therefore, the term resource is used throughout this chapter

6. There are three groups of actions relating to balancing that the Government has considered:

- reforming the calculation of cash out payments;
- Improving the System Operator (SO)'s approach to procuring reserves necessary to maintain system balance; and
- actions to better manage balancing of intermittent renewable generation.

7. Ofgem has recently consulted on whether to undertake a Significant Code Review (SCR) that would include making reforms to the cash out system and the approach taken by National Grid to maintain system balance[58]. The scope of the SCR has yet to be confirmed but it is expected to cover at least the first two groups of actions.

Calculation of cash out payments

8. For a number of reasons, the cash out price may not fully reflect the costs of ensuring supply and demand are in balance and at times will be too low. If prices in short-term markets do not fully reflect scarcity of generating capacity, forward prices will also be muted[59]. These forward prices are commonly used by developers as the basis of investment appraisals. Reforming the cash out price so that it is a truer reflection of the costs of that imbalance (i.e. to create more cost-reflective prices) should therefore give stronger signals for investments in new capacity.

9. The following are options for reform:

- **changing to a single cash out price:** There are currently different cash out prices for selling and buying electricity. Although this provides a strong incentive for balancing it may not be truly cost reflective. An alternative would be a single price (or one with a fixed spread between buy and sell);
- **changing to more marginal pricing:** The current scheme is "pay-as-bid" and the imbalance price is the average of the most expensive 500MWh of balancing actions. A scheme closer to marginal pricing would result in higher and more cost-reflective prices at times;
- **more effective allocation of reserve contract costs:** The costs associated with the SO purchasing STOR are allocated using the previous year's reserve usage as a proxy. These costs could be better targeted to the periods in which the reserve is actually used and so enhance cost reflectivity; and

[54] Ofgem has consulted industry in the prospect of conducting an electricity cashou significant code review. (http:www.ofgem.gov.uk/Licensing/IndCodes/CGR/Documents1/SCR%20open%20letter%20consultation_Aug10_final.pdf

[59] Alessandro Rubino (2009), Investment in Power generation. Deliver reliability in a competitive market (a paper produced for Ofgem Project Discovery)

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

Improvements to procuring of balancing services

10. A further way to improve cost-reflectivity of cash out and to also provide greater transparency is to introduce a reserve market. A reserve market is a short-term market (for example, day-ahead) run by the system operator to procure reserve resources. This would enable the value of reserve to be factored into the cash out prices in a way that more accurately reflect conditions on the day, and therefore cash out prices will be better targeted at the participants causing any shortfall [60]. These sharper price signals should enhance security of supply. To avoid distortion, resource that is receiving a capacity payment (e.g. under STOR) would need to bid its full costs into the reserve market. One option to ensure this would be that the SO is responsible for bidding the reserves they have contracted for into the market.

Actions to manage intermittent renewables

11. Wind generation is more exposed to being out of balance, because of the intermittent nature of the generation, and as such faces greater risk of paying cash out penalties. Some form of centralisation for variable renewable generators, such as that suggested by Ofgem[61], could allow variable renewables to face lower risks of imbalance and sell this output in the electricity market. For example it may be the case that different windfarms are out of balance in different directions (i.e. some generating more than predicted, some less), by aggregating these imbalances the overall imbalance is reduced.

12. Reducing the balancing risks for renewables could increase overall investment in renewable generation by tackling the barriers to entry that are created through cash out payments. It could also reduce the overall costs of balancing the system. Aggregation services such as this could be provided by a private company. The Government proposes to wait-and-see if such services are developed privately as a result of existing incentives to reduce balancing costs and an increasing opportunity for aggregation as the share of intermittent generation increases.

Actions to improve liquidity

13. Liquidity is an important feature of a well functioning market. Improving liquidity in the market could reduce security of supply risks as well as making

[60] Ofgem Project Discovery consultation (Feb 2010)
[61] For further details see Ofgem Project Discovery Consultation (Feb 2010) and Ofgem commissioned report by Brattle Group; An alternative trading arrangements for intermittent power, a centralised renewable market and other concepts (April 2010), http://www.ofgem.gov.uk/Pages/MoreInformation.aspx?docid=169&refer=MARKETS/WHLMKTS/DISCOVERY

significant improvements to the general operation of the GB wholesale electricity market:

- Firstly, a liquid market would give (new entrant) generators greater confidence that their product could be sold to suppliers if their generating plant is capable of producing electricity at the market clearing price. In the current system, because of the levels of vertical integration between supply and generation, it can be unattractive for new entrants

- Secondly, a liquid market makes for better price formation and stronger investment signals. As set out above, investment signals are derived both from short and long-term prices in markets, but in the GB market there is only a limited reference price over the longer-term. In such scenarios, the case for new investment is weakened, because of a lack of reliable price signals.

- Thirdly, it has been suggested[62] that poor liquidity in spot markets mean that closing out positions in a long-term contract could be difficult, resulting in a lack of long-term contracting, as discussed in chapter 2.

14. More detail on liquidity and actions to address it are given in chapter 5.

Actions to improve diversity and the demand side

15. Currently the GB market is primarily dependent on fossil fuel generation to provide the flexibility to respond to changes in demand or supply. Technologies such as demand side response, storage and interconnection offer the opportunity to have a greater diversity of technologies, so improving security of supply, as well as reducing emissions. A more dynamic demand side also increases competition and the effective functioning of the market.

16. Demand side measures (energy efficiency, Demand Side Response (DSR) and distributed generation) can reduce the need for investment in infrastructure by reducing overall need and making more efficient use of network and generation capacity. Experience from other markets (e.g. New England USA) shows that bringing demand side resources into the market can reduce the costs of the system. For example, participation of demand side resources in the first capacity auction run in the New England market (called ISO-NE), potentially saved customers as much as $280 million by lowering the price paid to all capacity resources in the market[63.] Benefits have also been seen in the other US market that has implemented this (called PJM[64]).

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[62] Why we need to fix our broken electricity market, special report, Poyry, 2008
[63] Cheryl Jenkins, Chris Neme and Shawn Enterline, Vermont Energy Investment Corporation (VEIC), “Energy Efficiency as a Resource in the ISO New England Forward Capacity Market”, ECEEE 2009 Summer Study Proceedings.
[64] PJM is a Regional Transmission Organisation (RTO) covering a large part of the eastern USA.

Demand Side Response (DSR)

17. For DSR to be fully effective the enabling technology and incentives for consumers need to be right. The main scope for immediate development lies in the industrial and commercial sectors with opportunities for aggregation of firm demand response, for example a supermarket chain being able to control usage of electricity for refrigeration across a whole network of stores. The roll out of smart and advanced meters, sharpening of the cash out price and appropriate amendment to the balancing and settlement system should facilitate the uptake of DSR[65]. Steps to improve market liquidity may also improve the ability of DSR to participate in the market by facilitating smaller trades and improving trading arrangements and price formation. Government will consider how existing measures such as the Carbon Reduction Commitment can work effectively with DSR.

18. DSR could be a particularly useful tool for Distribution Network Operators(DNOs) whose role is to manage the local electricity networks. DSR can reduce or delay the need for local network reinforcement by smoothing peaks in demand. However, the DNOs have no direct relationship with electricity consumers. Two of Ofgem's recently announced Low-Carbon Network Fund projects address this problem by promoting a partnership approach between suppliers and DNOs.

19. Domestic consumption offers more potential post 2020 with the likely electrification of heat and transport, which could significantly increase the amount of discretionary electricity use available for DSR. Increased automation via the introduction of smart appliances and widespread use of automated building energy management systems could play a vital role in assisting system balancing, empowering individuals and communities to actively participate in achieving a low-carbon future.

20. The Government welcomes Ofgem initiatives which strive to facilitate DSR across the supply chain, including the Low-Carbon Networks Fund and smart meter implementation.

Interconnection

21. The GB electricity system is currently relatively unconnected to other countries electricity systems[66]. Under the current arrangements, investments in interconnection are made on commercial terms, i.e. where developers identify an opportunity for arbitrage between markets then such investments take place. However, the nature of the investments make them high risk. As a response, Ofgem is developing a new regulated approach to interconnector investment which will be consulted on early in 2011. There is widespread industry support for Ofgem's consultation.

[65] Amendments following the smart meter roll out programme have also been proposed by Ofgem as a possible issues for examination by a Significant Code Review.
[66] There is currently about 2.5GW of interconnection capacity in the GB system, with links to the French and Irish markets.

Storage

22. As with generation investments, investments in storage are made on commercial terms. Reform of the cash out price will improve the economic case for storage, by making the costs of imbalance higher and more cost-reflective. Greater penetration of low short run marginal cost plant on the system will drive low prices at times of low demand. This should make storage a more attractive investment, because it increases the opportunity for arbitrage between periods of high and low demand. Another factor in the development of storage is the technological readiness of storage technologies (today, the only market-ready technology available for large-scale deployment is pumped storage[67]). Going forward as technologies mature, the costs will reduce, making them more economic and lower risk.

Energy efficiency

23. The European Climate Foundation Roadmap 2050 project analysis found that in order for energy efficiency to meet its full potential, it needs to be "recognised, financed and delivered on the basis that it is a power system resource"[68].

24. Government has a range of measures on energy efficiency, including the Carbon Emissions Reduction Target (CERT), and the Community Energy Saving Programme (CESP). These end in December 2012 and will be replaced by the Green Deal (see Box 9) and a new Energy Company Obligation.

25. An increase in DSR could also prove an important incentive to increasing energy efficiency across GB as a whole by increasing customers focus on how they can use energy more intelligently through use of energy management technology etc.

26. The Government believes that energy intensive sectors (EIS) need a clear understanding of how they will make the transition to the low carbon economy without significant risk of a fall in output and / or carbon leakage. The Energy Intensive Industry Strategy, is a joint project between BIS and DECC, with DEFRA involvement, which will look at greenhouse gas abatement potential in key energy intensive sectors, in light of the move to a low carbon economy. It will also assess the cumulative impact that various climate change and energy policies have on energy cost for these industries.

Box 9: The Green Deal
The UK housing stock is responsible for approximately one quarter of the UK's carbon emissions, with the energy consumption of non-domestic buildings accounting for around a further 15%. The majority of our building stock will therefore require some form of energy efficiency measure over the next two decades if we are to meet our legally binding carbon budget targets and set us

[67] There is currently approximately 3GW of pumped storage in GB, a significant proportion of which is used by National Grid to fine tune the system in the balancing mechanism.
[68] Brief on energy efficiency, ECF Roadmap 2050, (April 2010), http://www.roadmap2050.eu/attachments/files/EnergyEfficiency.pdf

on a path to 2050.

The Green Deal will enable private firms to offer all households and businesses in Britain energy efficiency improvements to their properties at no upfront cost.

At the heart of the Government's proposals is an innovative financing mechanism which allows consumers to pay back the costs over time through energy bills. This means consumers can see the savings which have been generated on the same bill as the Green Deal charge, with the payments being less than the expected savings.

The Green Deal differs from conventional lending – it is not a loan since the bill-payer is never liable for the full capital cost of the measures, only the charges which are due whilst they are paying the energy bills.

Implications for electricity market objectives

27. These measures have the potential to reduce some of the security of supply risks set out in Chapter 2. In particular, they should improve wholesale peak prices and incentives to invest in new generation. An indication of the potential impact on investment can be gained from analysis for Ofgem's Project Discovery[69], which indicated that capacity margins could be improved by 1-2% if prices were allowed to fully reflect market scarcity signals. Given the scale of estimated shortfall in capacity, these measures could have an important impact in improving the overall security of GB energy supplies.

28. However, these measures would not tackle all of the security of supply concerns outlined in chapter 2, in particular, even if the level of peak prices is improved, investors certainty in being able to capture these prices is not. So, there would potentially still be under-investment in particular in generation that is only required to run occasionally. Further, due to the cyclical nature of investment, there would continue to be a risk that capacity margins would remain low in some years.

Performance against criteria

29. These reforms enhance market functioning and reduce existing distortions, through improving market signals and removing specific barriers to technologies such as DSR. This can reduce barriers to entry and enhance competition in the sector, whilst ensuring that security of supply risks are reduced. As such, it is expected that they would have a positive impact on the wholesale market as a whole, ensuring it remains to operate cost-effectively.

30. The measures are designed to improve the incentives and signals for investment in capacity, but leave decisions on the optimum level of capacity to private sector investors. Because such investment decisions will only be made where there is a positive economic case, the risk of the economy paying for more capacity than is necessary to operate a secure electricity system is low.

[69] Ofgem Project Discovery consultation (Feb 2010)

31. While sharpening cash out prices could increase costs for renewable generation, other measures such as increasing market liquidity, and dual cash out arrangements would be of benefit.

32. The Government expects relatively low risks of unintended consequences to these measures being introduced, because the reforms would work with existing market arrangements and procedures that are relatively well understood by market participants and regulatory authorities. The reforms should allow the flexibility for the system to respond to future changes.

Conclusion on improving operation of current market

33. On balance, the Government believes that pursuing the reforms outlined above should enhance market functioning and can help reduce the security of supply risks. However, given that they do not address all of the risks to security set out in Chapter 2 and that these are set to increase as the volume of low-carbon generation increases, the Government has concluded that in addition it is necessary to introduce a capacity mechanism in order to provide greater assurance of the future security of electricity supplies.

Capacity mechanism options

34. Currently market participants decide the optimal capacity margin. An alternative is to determine the level centrally, and introduce a policy to reward the provision of capacity to ensure this margin is met – a capacity mechanism. In effect, this transfers the management of the risk associated with under-estimating capacity requirements to the government from market participants through the balancing mechanism and possibly through some reputational damage or loss of business. A capacity mechanism requires an assessment of the appropriate level of capacity and an incentive to deliver this desired level of capacity. The electricity security of supply monitoring arrangements in the Energy Bill currently before Parliament, will enable such assessments to be carried out. This section discusses the ways in which the incentive mechanism could be implemented.

35. In order to incentivise a specific level of capacity, some form of explicit payment for capacity would need to be introduced. Instead of developers receiving all their revenues from electricity sales, they receive a payment that attaches value to capacity or resource being available. This replaces volatile and uncertain scarcity rents from peak prices (that contribute to the developer's costs of providing capacity) with a constant payment rewarding capacity. There is more detail on 'scarcity rents' in the Impact Assessment, published alongside this document.

36. A capacity mechanism can improve security of supply in two ways. Firstly, by providing a regular revenue stream, it should ultimately deliver greater investment in new capacity by reducing the cost of capital. Secondly a higher (and smoother) capacity margin can be achieved than that which than an energy-only market would deliver. It can also be structured to reward demand-

side response, storage, and any other technology which can provide capacity. In particular, it is anticipated that a capacity mechanism will bring forward significant demand side response, as demonstrated by the experiences in North America discussed above.

37. There are a number of ways to implement a capacity mechanism, as summarised below:

- **capacity payment:** Reimburses all generators through a simple payment for available capacity. The level of payment is set by a central body, rather than through a competitive process;

- **capacity obligation:** an obligation on suppliers to contract with generators for a certain level of capacity or pay a buy-out price. The price for capacity is then set in a decentralised way, through these contracts;

- **capacity auction:** The capacity volume is set centrally a number of years (for example, three years) in advance. Price is determined by auction and paid to all resource (existing and new) clearing the auction. This mechanism is currently operated in the PJM and ISO-NE markets in the USA;

- **reliability option:** Also a forward auction, but is a financial market instrument (a "call option") rather than a physical instrument; generators must be available to the System Operator for dispatch above a defined strike price. This model has been proposed by several academics, but is untested; and

- **tender for targeted resource (TTR):** Capacity payments are only given to resource needed to make up any shortfall in the market. The level of payment is set through a competitive tendering process. Conditions on how the resource operates limit the market distortion.

38. While there are a number of broad types of capacity mechanism, the Government has identified three main design choices for a mechanism:

- whether price is set by a central body or in a decentralised bi-lateral market;

- whether price or volume is set; and

- whether the mechanism is market-wide or targeted, i.e. whether it pays all or only some resource.

Box 10: Capacity mechanism examples

Capacity payment: All Island Single Electricity Market of Ireland and Northern Ireland

The All Island electricity market is a day ahead pool, with explicit capacity payments based on availability. The amount of the capacity payments is set by a determination of the level needed to reimburse the full capital expenditure of the newest peaking plant over the life of that plant and the required target margin.

Capacity payments are made to generators based on a measure of their availability. The payment is broken into three sections, a fixed amount based on forecast demand, a variable amount based on expected levels of scarcity and an ex post payment based on actual scarcity. This mix provides a balance between providing certainty and reducing gaming. Payments are funded by charges levied on suppliers based upon their electricity consumption.

Capacity obligation: based on UK Renewables Obligation

A capacity obligation would be an obligation on suppliers to procure sufficient capacity from generators. The price of capacity is set in bilateral contracts between suppliers and generators, the obligation is on suppliers to procure sufficient capacity.

At the start of the year generators are issued with capacity certificates to reflect their de-rated capacity. Suppliers work in conjunction with the SO to calculate their peak customer demand plus the centrally-determined margin. Suppliers are then obliged to purchase capacity certificates to cover this capacity. At gate closure suppliers demonstrate they have purchased sufficient capacity to meet their customer demand plus margin by presenting capacity certificates. Generators notify not only of their intention to run or availability, but also their contracted capacity obligation.

Capacity auction: Reliability Pricing Model in PJM

The current PJM market (PJM is a Regional Transmission Organisation serving much of the North East USA) is a pool, with a forward capacity auction called Reliability Pricing Model. Demand side response and energy efficiency measures (negawatts) compete in the auction alongside generating capacity. All contracted resource receive the auction clearing price for the periods they are available, which is paid by an obligation on suppliers.

The independent SO holds a capacity auction three years in advance. To reduce gaming the required capacity is not fixed absolutely, i.e. at low prices the SO intentionally procures excess capacity, at high prices it procures less than target, leaving some to be procured in incremental auctions up to the delivery year.

Tender for targeted resource: Peak Load Reserve in Sweden

In Sweden, the SO is responsible for maintaining a maximum level of reserve during the winter period (2000MW), which is only used in extraordinary circumstances.

The SO runs a procurement exercise, the Peak Load Reserve (PLR) action, offering a price for sufficient reserve to come forward. The supplier receives compensation to remain on standby and is also paid when activated. PLR normally sits outside the market; the SO controls the reserve and is only offered on the rare occasions when there is insufficient supply to meet electricity demand. At these times the reserve is first offered into the commercial markets to allow a market based solution. PLR is offered at a price point which is just above the highest bid made in the market which did not achieve an increase in volume of capacity.

The cost of maintaining this PLR is recovered by the SO from a levy on the balancing responsible parties paid as a volume related fee. Any profit made by the SO in bidding the PLR into the market is recycled.

Setting the price centrally or bilaterally

39. The price of capacity can either be set centrally (through a payment or auction) or determined by the market (through a capacity obligation imposed on electricity suppliers, who are required to contract for a certain amount of capacity in addition to their expected demand). This choice is only applicable for market-wide mechanisms: targeted mechanisms by their nature need to be centrally determined.

Implications for objectives

40. Both options should enable a given level of capacity margin to be achieved. However, the interrelation between capacity reserves and reserves needed for the balancing mechanism will be significant as intermittency increases. Having both set centrally rather than one set bilaterally and one centrally will make this easier to manage.

Performance against criteria

41. The capacity obligation leaves more decision making to market participants, who may be better able to make such decisions. Further, because it is closest to our current market arrangements, it has a slightly lower risks of unexpected outcomes and would be compatible with existing institutional arrangements.

42. However, experience of other obligations and our current bilateral electricity trading arrangements suggest that a centralised approach has a number of advantages. A centrally-set price and contracts will be more transparent than in a capacity obligation, giving a lower risk of double payments and gaming. There will be fewer barriers to entry than in a capacity obligation, which would reinforce the current advantages of vertical integration.

Setting the price or the volume

43. A central body could ensure sufficient capacity is procured by either setting a price of capacity with the aim of ensuring it receives sufficient volume (a capacity payment), or by setting the volume of capacity required and allow the market to discover the price (a capacity obligation, auction or targeted tender).

Implications for objectives

44. Both setting price or setting volume options should enable a given level of capacity margin to be achieved. However, there is more certainty of getting a desired capacity margin if volume is set.

Performance against criteria

45. Setting the price for capacity centrally is initially attractive because it is relatively straightforward to determine and the approach is and more transparent than other mechanisms and is compatible with existing institutional arrangements. However, there is significant risk of either over-paying or of not obtaining the desired level of capacity, as the level of payment is extremely difficult to set correctly. This is demonstrated in the modelling undertaken for this project[70]. When the level of payment was set at a level needed to incentivise new entry peaking plant and deliver a capacity margin of 10%, it resulted in margins well above this (figure 9 below). Scaling the payment by 70% gave similar capacity margins in a more efficient way, but in scenarios where new build was needed this level of payment would then be too low leading to low margins. This is contrasted with experience to date, of capacity auctions in PJM and NE-ISO and competitive tendering for STOR in which the competitive process enables price discovery, which allows the level of payment to flex with changes in the generation mix.

A market-wide or targeted capacity mechanism

46. Typically capacity mechanisms pay all generators the same (termed market-wide capacity mechanisms in this document), as all generators would otherwise receive the scarcity rents that the capacity payment replaces. However, capacity payments could be paid to only some generators (e.g. the peaking plant that is only used for a small number of hours each year) if any resulting market distortion (i.e. reduction in peak prices) can be effectively mitigated. This document refers to such an approach as a targeted capacity mechanism.

A market wide capacity mechanism

47. There are a number of different types of market-wide capacity mechanism: capacity obligations, capacity payments, capacity auctions and reliability

[70] Op cit, Redpoint (Dec 2010)

options. This section discusses them in general terms, comparing them to a targeted capacity mechanism. For modelling purposes the Government has used a capacity payment scheme (although the preference remains for a capacity auction approach).

48. If support to low-carbon generation is given as a payment based on availability (i.e. for de-rated capacity) then it may be appropriate combine this with a capacity mechanism. One instrument could then be used to reward both decarbonisation and capacity, with a higher payment for capacity that also delivers low-carbon, as proposed by Dieter Helm[71].

A targeted capacity mechanism

49. Under a targeted capacity mechanism, capacity payments are only made to those generators that provide the additional capacity needed to make up any anticipated shortfall in the capacity margin.

50. A central body would be required to estimate the likely shortfall of capacity provided by the market compared with the centrally-determined requirement, and therefore the amount of capacity for which they should tender. A range of different types of resource could be procured and offered different payments and/or lengths of contracts as necessary. The tendering process would determine the level of the capacity payment. The contracts would also need to set out how utilisation costs would be paid for and the circumstances in which the resource procured would be used. This will need to be very clearly defined in order to ensure the rest of the market can function effectively.

51. There are two main ways in which the resource (whether supply or demand side) could be dispatched:

- **last resort dispatch** (strategic reserve): the resource is only used after all other resource has been exhausted (similar to the Swedish market, Box 9); and

- **economic dispatch** (extending STOR Short Term Operating Reserve): the resource is used when required to by the System Operator. It is dispatched when it is cost effective to do so, which may be before all other options are exhausted.

52. It may be possible to take different approaches for different types of resource (e.g. to treat DSR differently to generation capacity).

53. Last resort dispatch would minimise market distortion. Economic dispatch could reduce overall costs because capacity is expected to have higher utilisation rates, but risks greater market distortion. This would need to be mitigated by including these actions in the cash out price in a cost-reflective

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

way. The choice between these approaches is a complex trade-off. For simplicity, the Government has modelled the first approach.

Implications for objectives

54. The modelling undertaken for the project suggests that both a market-wide and targeted capacity mechanism could have a significant impact on the capacity margin, and both could be designed to incentivise demand side resources, and therefore could contribute to decarbonisation targets.

55. Figures 9 and 10 show the effect on the capacity margin of a market-wide mechanism and targeted capacity mechanism respectively [72]. Both were modelled on achieving a 10% margin. Figure 9 shows that a higher than targeted margin was achieved, but the Government attributes this primarily to the fact that a capacity payment scheme was used rather than an auction model (where the central body would be able to better control volumes of capacity being supported through the mechanism).

56. The main difference between the two approaches is the type of the resulting additional capacity:

- in the modelled market-wide capacity mechanism, this was entirely existing plant that no longer chose to close under new EU environmental legislation (the Industrial Emissions Directive) as this was the lowest-cost option for generators, allowing them to maximise returns from the mechanism; and

- in the targeted capacity mechanism, the central body would choose the mix and so there was also some new-build OCGT (simulated in the modelling, by forcing certain technological outcomes). This gives greater flexibility in the type of resource supported which may be advantageous depending on future market developments (for example if needed to provide back-up for intermittent generation).

[72] A fixed FIT option has been used to demonstrate the impact of a market-wide capacity mechanism because there are less complex interactions with a fixed FIT which decouples the low-carbon generation from the market.
[73] EMR Redpoint simulations (2010)

Figure 9: De-rated capacity margins with a capacity payment for all[73]

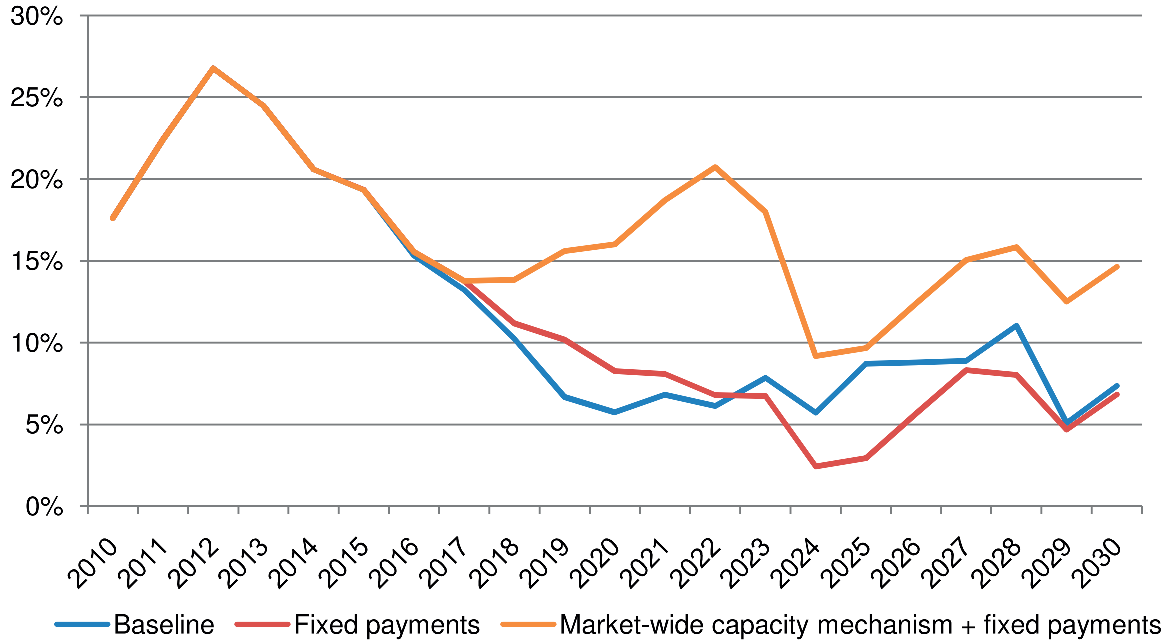
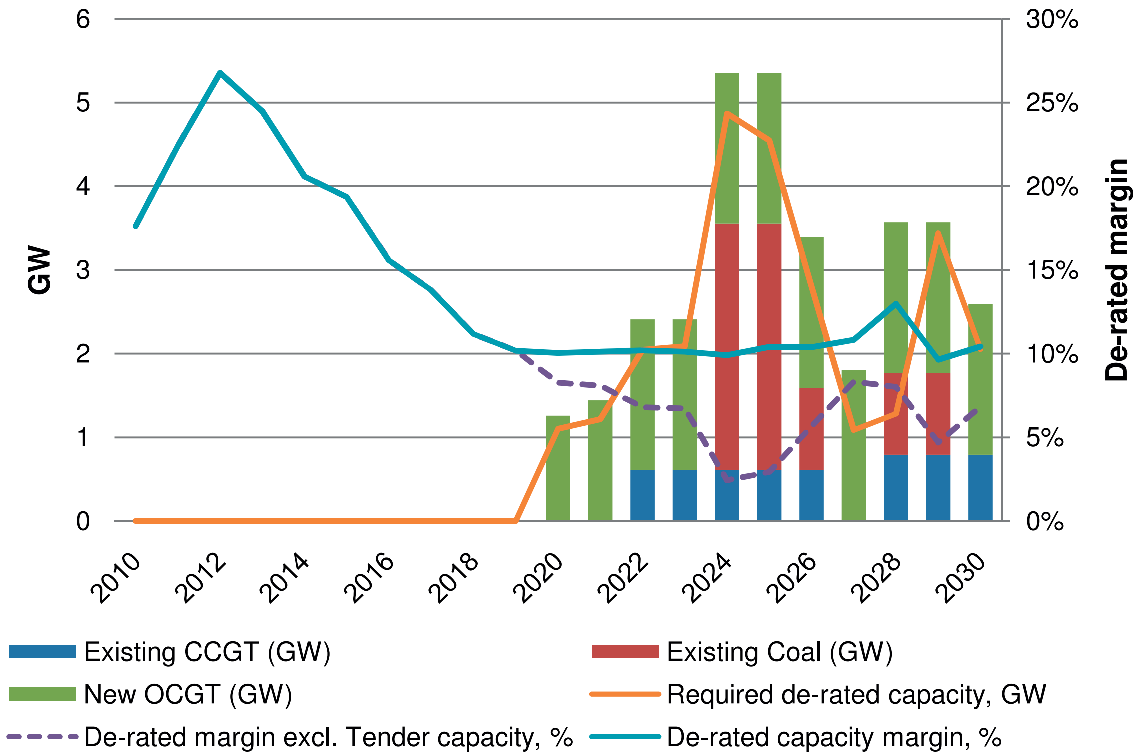


Figure 10: Impact of targeted capacity mechanism on de-rated capacity margin[74]



57. In the figure above, the purple line shows the expected capacity margin without a capacity intervention, which is below 10% during the 2020s. The green line shows how much capacity (in GW) would be needed to bring this

[74] EMR Redpoint simulation showing market-wide fixed payments and targeted capacity tender

margin up to 10%. The blue line shows the effect on the capacity margin of tendering for this amount of capacity with the targeted capacity mechanism. The margin is now around the targeted level during the 2020s. The bar charts show the break-down of the different types of resource that have been procured in this example (new OCGT and existing gas and coal plants).

58. A further distinction between the models is the greater risk of market distortion in the targeted capacity mechanism. There are two potential effects:

- **Effect on peak prices:** in the ‘economic dispatch’ model, if the capacity payments made are not accurately fed into the ‘cash out’ price other capacity will not achieve an adequate return. In the last-resort model, peak prices should be largely unchanged as the resource is only provided when all other available generation is in use;

- **‘Slippery slope’ effect:** if being in the capacity mechanism and receiving a capacity payment is more attractive than remaining wholly in the market , it could lead to lack of investment outside of the mechanism, meaning that the central body has to procure ever more generating capacity.

59. These distortions could undermine the mechanism’s ability to ensure secure supplies of energy. However, to some extent these can be mitigated through design (as demonstrated by the Swedish Peak Load Reserve, which is based on a last-resort model). The Government also considers the risks to be relatively small because the modelling suggests that there is a limited need for the central agency to have to procure significant capacity to maintain a margin of about 10% (5GW in the period to 2030).

Performance against criteria

60. The overall cost of a capacity mechanism depends on the level of the target margin chosen. Costs will result from the generation costs incurred by existing plant that would otherwise have closed and any build costs and generation costs of new plant incentivised. This will be offset by the benefits of the additional security of supply provided and by savings from reduced costs of capital from lower investor uncertainty. For illustration, the modelling undertaken for the project, with a target margin of 10%, showed that in overall net welfare terms a market-wide capacity mechanism had a negative NPV impact of £0.78bn[75] and £0.7bn for a targeted capacity mechanism. However, a positive NPV would result if a higher value was placed on security of supply or if a lower target margin had been chosen.

61. The modelling did not include the potential for new DSR providers. Based on international experience (discussed above), costs could be lower if this was included. DSR would also improve competition, and have a further beneficial effect on security of supply through increasing diversity of resources.

[75] Refer to Impact Assessment for further details. This was done by comparing against a fixed FIT option without a capacity mechanism.

62. The impact of a capacity mechanism on consumer bills is expected to be small. In the modelling, the market-wide capacity mechanism added around 1% to the average annual household electricity bill, in the period to 2030. The effect of a targeted capacity mechanism would be minimal. The modelling illustrates the differences between the options; the bill impact will depend on what level of target was chosen. A market-wide capacity mechanism pays the same capacity payment to all types of resource. However, they may not have equal value in terms of maintaining security of supply. A targeted capacity mechanism can run different tenders for different types of resource need, and so pay different prices. This is expected to result in lower rents/producer surplus than under a market-wide capacity mechanism. This is demonstrated in the modelling of the policy: existing plant was given a lower level of capacity payment than new plant. This resulted in a saving of £0.2bn in NPV terms, compared to paying all plant the same.

63. In addition to the direct cost of the mechanism, it would also create **administrative costs** to operate. Based on the running costs of PJM and of the Renewables Obligation it is estimated that a full capacity auction cost could cost between £3-£10 million per year to run the auction and provide additional market monitoring[76].

64. **Rent-seeking opportunities** could arise depending on the means of implementation. In particular, there are risks to gaming which arise from Government taking on the risk of there being insufficient capacity on the system, and setting a target level for capacity. These risks have been largely overcome in PJM and ISO-NE largely through a significant centralised role in setting detailed rules for the capacity mechanism and high levels of market monitoring[77]. This would be harder to achieve in GB's bilateral market arrangements. The effect should be lower in a target capacity mechanism compared to a full capacity mechanism as there are fewer participants.

65. Under current arrangements resource covers all its costs through revenue from selling electricity[78]. The capacity mechanism splits this into two revenue streams – one for capacity and one for electricity. To avoid **overcompensation** or "double payments" the revenues received from the electricity price should be reduced, corresponding to the increase from the capacity payment. This reduction has been assumed to happen in the modelling. In practice, competition and liquidity should help drive the electricity price down so that double payments are avoided. This is supported by experience in the PJM market, but this cannot be guaranteed. As such, wider market reforms to increase competition would also be needed to ensure this. But to fully address these issues, more significant change such as a centralised trading arrangement (a pool) would be needed, and so there would be added pressure to make this type of disruptive change. The overcompensation risk should be lower in a target capacity mechanism compared to a full capacity mechanism as there are fewer participants.

[76] See EMR Impact Assessment.
[77] Communication with Monitoring Analytics, Pennsylvania and PJM State of the Market Report 2009, http://www.monitoringanalytics.com/reports/PJM_State_of_the_Market/2009.shtml.
[78] In addition, they may get revenue from providing ancillary services to the SO.

66. Introducing a market-wide capacity mechanism would be a fundamental change to the UK electricity system, therefore there is a significant risk of unintended consequences. As a targeted capacity mechanism is a relatively small intervention in the market – with an estimated 5GW of capacity required to 2030 to maintain margins at 10% - it would be likely to have lower implementation risks. Further, the targeted capacity mechanism draws on experience with our own STOR arrangements and the Swedish Peak Load Reserve, which is closer to the GB market than PJM or ISO-NE, where a market-wide approach is adopted.

67. There is a risk of an investment hiatus during implementation of a market-wide capacity mechanism, given the scale of change, although as the outlook suggests capacity margins will remain high for several years this ought not to be significant. With a targeted capacity mechanism there is the possibility of investment hiatus, as many generators may choose to "wait and see" either because the returns from generation in the capacity market are more attractive than in the energy market or in anticipation that government will eventually move to a market-wide capacity mechanism.

68. A targeted capacity mechanism would be more flexible to respond to future changes than a market-wide capacity mechanism because it has more opportunity for the design to evolve, making it durable and more able to adapt to be compatible with European markets as interconnection increases.

69. Overall, the Government's initial preference is for a targeted capacity mechanism, subject to market distortion being successfully mitigated through implementation. While a market-wide mechanism avoids potential market distortion it is a considerable intervention in the market. This leads to a significant risk of unintended consequences, market disruption and a lengthy implementation phase. Further, by paying all resource the same there is a risk that the 'right' type of flexible resource is not incentivised and that windfalls are given to some generators. A targeted capacity mechanism is a significantly smaller intervention and, if necessary, can target different types of resource, so that these risks are reduced. On balance, and drawing on evidence of successful implementation in markets such as Sweden, the Government believes that the targeted capacity mechanism is more attractive

Further design questions

70. Further design questions include the role of DSR, energy efficiency, storage and resource located across an interconnector and whether the mechanism should have a locational element.

DSR, storage and capacity through interconnection

71. The Government recognises that there are significant advantages in ensuring that DSR can play a full part in the electricity market. This is a key criterion in the design of any capacity mechanism. We believe this should be possible in any of the designs discussed above. For example, the Swedish Peak Load

Reserve has seen the amount of DSR offered increase annually, now accounting for 23% of total reserves[79] in comparison with a 10% contribution to GB's STOR requirement[80]. It is also anticipated that storage would be able to participate in any capacity mechanism.

72. Experience in the US markets shows that it is possible to run a capacity mechanism in one market that calls on resource in another market, even if that does not have a capacity mechanism, without unintended consequences. For example, PJM trades with MISO (an adjacent market that does not have a capacity mechanism); a condition of the capacity payment is a recall provision that avoids double payments. However, under market coupling, it may not be possible to reserve interconnector capacity. More detailed consideration of these issues will be needed during the period ahead of the White Paper.

Energy efficiency

73. A capacity mechanism can be designed to reward energy efficiency for the permanent reduction in demand that it offers. For example, in PJM and ISO-NE energy efficiency is rewarded with a capacity payment in the market-wide forward capacity auctions. For example, in the PJM 2012/13 auction, the first PJM auction in which energy efficiency is eligible for a capacity payment, 568.9 MW of energy efficiency measures cleared the auction, 0.4% of the market[81].

74. Under a targeted capacity mechanism, energy efficiency measures, although not contributing to the flexibility of the system, could potentially be rewarded for the reduction in demand offered at peak hours. This revenue would not cover the full costs of the resource, just as capacity payments are not a full revenue stream for generators. Instead, it would supplement the current revenue streams, as discussed in Section X above.

75. The Government recognises that this is more complex than including other demand side technologies. For example, there may be unintended consequences of differentiating energy efficiency in the electricity sector from energy efficiency. Also, wider energy efficiency would be "running" at all times, and not as a "last resort" and so has the potential for greater market distortion. However, given the advantages of putting increasing supply and reducing demand on an equal footing, this possibility should be explored further.

Locational elements in a capacity mechanism

76. At times of system tightness, it is more efficient if the additional resource that is provided to the system is located close to areas of high demand. This minimises system losses and avoids any network constraints on congested areas of the network. A capacity mechanism could provide greater reward for capacity that is available at times of tightness in geographical locations where

[79] Enhancement of Demand Response, Nordel Demand Response Group, 18 April 2006.
[80] National Grid.
[81] The Role of Forward Capacity Markets in Increasing Demand-Side and Other Low-Carbon Resources: Experience and Prospects, Meg Gottstein and Lisa Schwartz, The Regulatory Assistance Project , available at: http://www.raponline.org/ForwardCapacityMarkets

demand is high. For example, in the market-wide capacity auction in Pennsylvania, New Jersey and Maryland (PJM) there are separate capacity auctions for locations that are experiencing distribution or transmission bottle-necks in the delivery of electricity to customers. Different auctions could be held for different geographical areas, so that resource in an area of high demand receive a price that is reflective of demand in that area.

77. The targeted capacity mechanism is likely to cover only a small amount of resource and only flexible technologies such as DSR, as discussed above. This would mean that the locational impact would not impact on resource such as wind and nuclear generation that is limited in where it can locate,. However it would mean, for example, that DSR was targeted at those geographical areas in which it could provide most benefit.

Conclusion on capacity mechanisms

78. The Government is committed to ensuring that the market enables an adequate return to be made on efficient levels of capacity, including that which is only occasionally needed. It also recognises that in this area, a programme of improvements by Ofgem and Government is likely to be the most appropriate approach, including changes to balancing arrangements, improvements to liquidity and transferring the responsibility for ensuring an adequate capacity margin from the market to Government. This programme of work will also need to consider how best to minimise the opportunity for successful rent-seeking behaviour by market participants.

79. Fulfilling this responsibility will require the introduction of a capacity mechanism. The Government is proposing the following design preferences for a capacity mechanism:

- a centralised system (i.e. an obligation on a single central body such as the system operator) rather than decentralised system;
- an approach in which volume is set rather than the price of capacity;
- a targeted approach, rather than offering payments to all generators

Question 19: Do you agree with the assessment of the pros and cons of introducing a capacity mechanism?

Question 20: Do you agree with the Government's preferred policy of introducing a capacity mechanism in addition to the improvements to the current market?

Question 21: What do you think the impacts of introducing a targeted capacity mechanism will be on prices in the wholesale electricity market?

Question 22: Do you agree with Government's preference for a the design of a capacity mechanism:

- **a central body holding the responsibility;**
- **volume based, not price based; and**
- **a targeted mechanism, rather than market-wide.**

Question 23: What do you think the impact of introducing a capacity mechanism would be on incentives to invest in demand-side response, storage, interconnection and energy efficiency? Will the preferred package of options allow these technologies to play more of a role?

Question 24: Which of the two models of targeted capacity mechanism would you prefer to see implemented:

- **Last-resort dispatch; or**
- **Economic dispatch.**

Question 25: Do you think there should be a locational element to capacity pricing?

CHAPTER 5 – Analysis of packages

Chapter Summary:

Premium feed-in tariffs and Contracts for Difference combine well with carbon price support: payments from government can be reduced as the wholesale electricity price is higher and generators would be receiving a higher proportion of their revenues from the wholesale price. This has two important consequences: firstly, it reduces the liabilities for investors before the premium payment is made or the CfD settled; secondly, benefits for the public finances because it reduces flows from government to generators.

However, combining a premium FIT with the carbon price support mechanism makes it more difficult to accurately set the level of support for low-carbon generators and avoid either under- or over-rewarding their investments. As such, the modelling suggests that the most cost-effective combination would be a contract for difference and the carbon-price support mechanism.

Payments to low-carbon generation under fixed feed-in tariffs do not change with the introduction of carbon price support as there is no link to the wholesale electricity price. There is therefore limited interaction, however the Government does not consider this package to be coherent: the main inconsistencies arise from the combination of an intervention designed to correct market failures and then allow market forces to determine outcomes (the carbon price support mechanism) with a more centrally determined approach (fixed payments).

`Interactions between all the policies to provide low-carbon generation revenue support (feed-in tariff and carbon price support) and a targeted capacity mechanism are limited and are not significantly altered by the choice of decarbonisation mechanism.

The targeted EPS has very limited interactions with the other mechanisms.

1. This section considers the impacts of combining each of the three types of feed-in tariff with an Emissions Performance Standard designed to prevent the operation of new coal-fired power stations, a capacity mechanism focussed on ensuring sufficient capacity will be available and carbon price support, to make a package of market reform. For the purposes of this project, the Government has assumed a moderate level of carbon price support (£30/tCO_2, which is also the central case in the separate HM Treasury/HMRC consultation).

2. The following three packages are therefore considered here:

- **Package: option 1** – CPS, EPS, targeted capacity mechanism.
- **Package: option 2 –** Premium payment, targeted capacity mec**h**anism, CPS, EPS
- **Package: option 3 –** CfD, targeted capacity mechanism, CPS, EPS
- **Package: option 4 –** Fixed payment, targeted capacity mechanism, CPS, EPS

3. Final decisions on the carbon price support, including the initial levels will be taken at Budget 2011. For the purposes of the modelling undertaken for this project, the carbon price support mechanism has targeted so the combined carbon price (with the EU ETS) reaches £30t/CO_2 by 2020. This is indicative, and respondents should not draw conclusions about future decisions to be taken on the future trajectory for the carbon price support mechanism,

4. This chapter will assess the coherence of each of the packages and also the implications for the final Government energy market objective: affordability. This will be achieved through an analysis of the expected impact on electricity bills up to 2030.

5. The effectiveness of the reform packages is also reliant on action being taken to improve liquidity. This chapter therefore concludes with a discussion of liquidity issues and actions need to resolve them.

Overall impact on energy market objectives

Decarbonisation

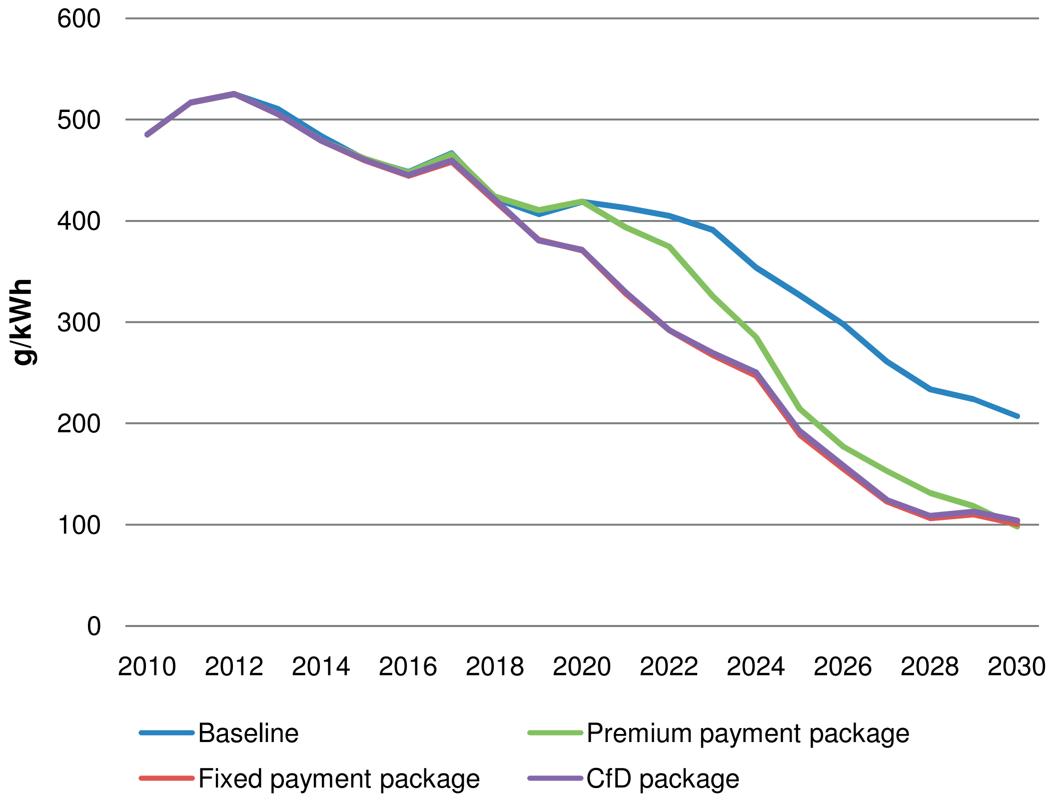
6. The modelling suggests that all four of the packages set out above are capable of delivering the 2030 decarbonisation level of 100gCO_2/KWh if the incentives are set at the right levels. Figure 10 below shows the decarbonisation trajectory under each of the packages. The modelling indicates that there is more investment sooner with the packages that include the fixed payment and CfD options because (as discussed in chapter 3) the lower risks and consequent cost of capital means that low-carbon projects are economic earlier in the period (given a rising carbon price).

7. The Government has not modelled the bill and price impacts of package one (which does not have a feed-in tariff) in the same way as for the other packages. This reflects the Government position that the carbon price support mechanism should be part of a package of reforms to encourage low-carbon investment and not the sole policy tool for driving emission reductions in the electricity sector. This is also in line with the Coalition Agreement commitment

to introduce a system of feed-in tariffs (to work alongside the carbon price support mechanism).

8. The fixed payment and CfD packages result in a higher take-up of CCS by 2030 than under the premium payment package (7GW and 2GW respectively). The reasons for this are discussed below. The fixed payments and CfD packages would be more cost-effective if the incentives in these options were set to bring on nuclear rather than CCS.

Figure 11: Decarbonisation trajectory under each package compared with the baseline case



Security of supply

9. The modelling shows that in all of the reform packages, the risks to security of supply are low as the targeted capacity margin of at least 10% is maintained throughout the period to 2030. This is a direct result of the inclusion of the targeted capacity mechanism in all of the lead packages.

Affordability

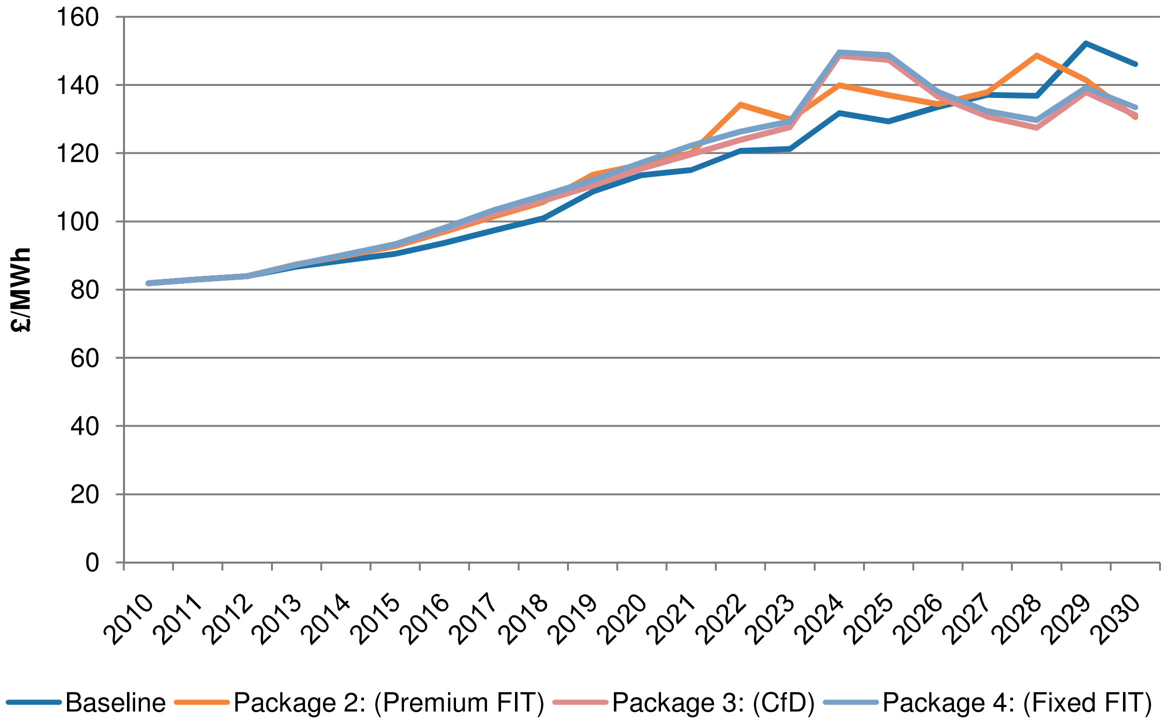
10. The Government is committed to minimising costs to consumers and subsequent impacts on fuel poverty in the transition to a low-carbon energy system. The costs to consumers arising from the transformation of electricity to low-carbon play a critical part in the overall costs.

11. The impact of these reforms on household bills to 2020 will be broadly in line with existing plans as set out in the Annual Energy Statement[82]. In the longer run to 2030, while no targets or trajectories have been set for this period yet, the Government believes the lead package of reforms would deliver an effective pathway to 2050, security of supply and consumer bills that are lower than continuing with existing policies. With an illustrative decarbonisation benchmark of 100gCO2/kWh in 2030[83], the lead package of reforms would result in a period of higher investment in the 2020s and household bills would then be 4% (around £29/year) lower in the five year period up to 2030 than continuing with existing policies despite delivering a higher level of ambition. The actual level of impact depends on the rate of decarbonisation among other things and since this has not yet been set it is not possible to be more definite at this stage. The key conclusion the Government draws from the modelling is the trend in bill impacts: small impacts on bills in the near term, but in the longer-term bills are expected to fall by 2030, despite delivering more low-carbon investment. The individual bill numbers in any given year are less insightful because they will be affected by other issues in the sector, such as the capacity margin in that particular year which will also affect wholesale prices.

12. The impact of the reform package on business bills to 2020 will also be broadly in line with existing plans as set out in the Annual Energy Statement, though the reform package may have a small impact on bills up to 2020 (2% higher). While no decarbonisation trajectory has been set the impact in the longer term to 2030 might, on the basis of the modelled benchmark of 100g/kWh lead to somewhat higher bills in the short term as more investment flows through into low carbon, and then bills that are 5% lower (£77,000) in the 5 year period to 2030 than continuing current policies (despite delivering a higher level of ambition). Impacts on different sizes and different kinds of businesses will of course be different than this average. Further analysis of the impact of this reform package on businesses will be undertaken for the White Paper.

[82] DECC Annual Energy Statement and Estimated impacts of energy and climate change policies on energy prices and bills, July 2010

Figure 12: Time weighted consumer electricity prices (£/MWh, real 2009 prices)



Source: Redpoint analysis, 2010

Distributional impacts

13. Increases in average domestic electricity bills can have disproportional impacts on consumers on low incomes. Lower-income households, although facing a lower absolute increase in their electricity bill due to lower levels of consumption, will expend a larger proportion of their expenditure on electricity compared with the average household.

14. Distributional analysis provides insights into the affordability of the reform options for different households by looking at the increase in the electricity bill as a percentage of total household expenditure, when compared to the baseline. This analysis shows that the highest impact is on households in the lowest income deciles in all EMR options, although the additional impact on bills from the proposed market reforms compared with the baseline is very small. Under all packages, the impact is less than a 0.2% increase in bills.

15. It should be noted that the same level of renewables is achieved in the baseline in 2020 as under the EMR options, therefore the overall impact of the options compared to the baseline are relatively small and largely driven by the impacts of carbon price support.

16. The Government is taking steps to mitigate the impacts of the decarbonisation of the economy on the lowest income deciles through initiatives such as the

Green Deal. The Government is taking steps to mitigate the impacts of the decarbonisation of the economy on the lowest income deciles through initiatives such as the Green Deal. As part of its energy intensive industries strategy, Government will also carefully assess the cost of energy and climate change policies, including the proposals set out in this Consultation, on energy using businesses and commercial customers.

Overall coherence of reform package

17. This section of the consultation document is designed to assess whether the proposed reforms are complementary when combined into an overall package. There are a number of factors which are similar in all of the reform packages, most importantly:

- **impact of an EPS:** It sends a clear regulatory signal to investors, in addition to the economic signals from the carbon price. It has very limited interaction with any of the other policy options. It also provides an absolute backstop to prevent new construction of the most carbon intensive type of power station;

- **impact of the carbon price support on existing generators:** Regardless of its role in changing investor behaviour with regards new power stations, which differs depending the model of feed-in tariff, the carbon price support mechanism has an important impact on the dispatch decisions of existing generators in all the packages. All other things being equal, supporting the carbon price will increase the relative attractiveness of lower emitting plant, for example encouraging coal to gas switching. The modelling shows that the impact of this on overall emissions can be significant, with cumulative emissions from the GB electricity system up to 5% lower across the period to 2030[84]. As a result, the emissions in each package are lowered with the addition of the carbon price support mechanism (targeted at a combined carbon price level in 2020 of £30t/CO_2;;

- **impact of the targeted capacity mechanism:** The impact is similar under each package in that it results in the capacity margin being maintained at a pre-determined level. However, in different packages, the amount of generation that is procured by the system operator through this mechanism will differ; and

- **combined impact of the capacity mechanism and carbon price support:** the carbon price support policy improves the security of supply outlook for all scenarios because it pushes up wholesale prices, making additional investment in capacity economic. As such, this reduces the amount of capacity that is tendered through the targeted capacity mechanism. However, the modelling shows this effect is relatively small. The addition of the carbon price support into a package on average increases capacity margins by

[84] Op cit, Redpoint (Dec 2010

0.5%[85]. As such this does not affect the rationale for specific interventions on security of supply.

Package 1 – Carbon price support + EPS + capacity mechanism

18. In package 1, the carbon price support alone drives investment in low-carbon generation, whilst at the same time (as discussed above) it restricts the development and operation of unabated fossil fuel generation.

19. As explained in chapter 3, the impact of the carbon price support mechanism is sensitive to the degree of credibility that it may have with developers and financiers. In addition, given the comparatively limited impact that carbon prices have on the electricity price, for example a 50% increase in the carbon price is expected to result in only a 15% increase in electricity price[86]. The level at which the carbon price support would need to be set at to deliver all the low-carbon investment needed on its own require a combined carbon price level of £50t/CO_2 by 2020 would be required,. This would mean increasing the level of the price support mechanism quickly and to a relatively high level.

20. While this combination of policies would be an expensive way to deliver decarbonisation and security of supply, the combination of interventions is coherent. The focus on this package is on using Government policy levers to alter prices in the electricity market to reflect the Government's objectives, and then to allow market forces to decide how these objectives should be made. For example, generators would decide on what type of generating station to build, based on their view of the economics in a world which valued the contribution of individual low-carbon technologies equally.

Package 2 - Premium payments + carbon price support + EPS + capacity mechanism

21. The Government also considers package 2 to be coherent: carbon price support and premium payments are complementary as they both drive investors to increase their expectations of future revenues. Such revenues would either come from an increased electricity price (through the carbon price support mechanism) or additional revenues from the FIT support scheme. In practice, increases in carbon prices would allow lower support payments through the premium FIT scheme.

22. Carbon price support also provides more certainty around the rising carbon price. As discussed in chapter three, there is a link between expectations of forward electricity prices and levels of support needed under a premium FIT model to make low-carbon generation attractive. and therefore reduces the potential for excessive rents to producers and associated higher costs for consumers. Greater certainty over a rising carbon price in the future should make it easier to more accurately set the levels of the premium FIT and

[85] Op cit, Redpoint (Dec 2010).
[86] Op cit, Redpoint (Dec 2010

therefore reduces the potential for producers to earn more than an economic return on their investments at the expense of consumers. Providing greater certainty of a future rising carbon and as such electricity price, will reduce the level of support payment required by generators before they decide to proceed with new low-carbon generation projects. This will reduce the flows from the Government to generators through the FIT, reducing the impact on public finances.

23. However, combining the instruments together does not eliminate all risks to over (or under-) rewarding low-carbon generators. Once the level of support is set for the premium FIT, it does not change in response to changes in the electricity price. This means that if the Government changed the carbon price support mechanism to increase the target carbon price, it would push up the electricity price, but existing generators would continue to receive the same level of support under the premium FIT. This would enable them to earn a more than economic return on their investment, unfairly, at the expense of the consumer. If the electricity price were lower than expected, for example because the Government reduced the target carbon price in the carbon price support mechanism, generators may be under-rewarded. Government would find it difficult to retrospectively adjust the premium FIT rates to respond to either under or over-rewarding investment – without significantly increasing uncertainty for investors..

24. Combining a carbon price support mechanism with the premium payments package leads to lower financing costs when compared to premium payments used in isolation. This is because the carbon price support mechanism provides additional certainty to investors about the revenues they will receive from the wholesale electricity price and therefore reduces their cost of capital. This is in addition to the increased revenue certainty that the premium FIT payments provide. This effect is relatively small and is illustrated by the modelling that shows that when the same decarbonisation and technology profiles are achieved, premium payments are £4bn[87] more expensive than fixed payments and CfD, but with carbon price support the additional cost is reduced to £3.3bn.

25. An important difference between this package and packages three and four, is that Government's ability to target specific technologies is reduced. This is because with carbon price support, low-carbon generation obtains a higher proportion of its revenue from the wholesale electricity price. This makes it harder to set premium payments that effectively differentiate between technologies. This is demonstrated in the modelling when premium payments resulted in less CCS coming forward than under the CfD and fixed payment packages; in effect generators are choosing instead to build lower-cost technologies such as nuclear.

[87] NPV 2010-2030, £m (2009 real)

Package 3 - Contracts for difference + carbon price support + EPS + capacity mechanism

26. The Government considers this package to be the most coherent and also the most cost-effective. Carbon price support and CfD are complementary: as carbon price support pushes up average wholesale electricity prices, it reduces the revenues that flow from the Government to generators when the CfD is settled. In effect, the carbon price support mechanism reduces the size of extra support that is channelled through Government. This is has two important consequences:

- Firstly there is a positive impact on investment decisions: it reduces the liabilities for investors before the CfD is settled as they are getting a higher proportion of their revenues from the wholesale price. Carbon price support and CfD are both therefore contributing to this positive investment decision.

- Secondly, there are important considerations for public finances as the flows from government to generators would be lower than without carbon price support.

Package 4 - Fixed payments + carbon price support + EPS + capacity mechanism

27. In contrast to the above packages, at this stage the Government does not consider this package to be coherent. The main inconsistencies arise from the combination of a intervention designed to correct market failures and then allow market forces to determine outcomes (the carbon price support mechanism) with a more centrally determined approach (the fixed payment system).

28. Having said that, there is limited interaction between the fixed FIT schemes and the carbon price support mechanism. This is because generators with fixed FIT contracts do not receive any of their revenues from the wholesale electricity price and are therefore unaffected by changes in its level. The impact of the carbon price support mechanism is limited to changing behaviour of existing fossil-fuel generators and switching to lower emission fuels, or bringing forward plant closure dates.

29. The Government also considers this an unattractive reform package because of the loss of the signals for efficiency which are unavoidable with the introduction of a fixed FIT scheme.

Box 11: High Demand Scenario

In current DECC scenarios, the central case for electricity demand is expected to rise slightly in the period to 2030 (7% over 2010 levels). The increase is driven by a move towards the use of electricity in the heat and transport sectors, which is offset to some extent by improvements in efficiency.

However , it is possible there will be a greater than expected shift into electricity from the heat and transport sectors will be more marked, particularly in the late 2020s, which would result in a higher level of electricity demand. To investigate the impacts of higher electricity demand, the modelling tested the EMR packages against a higher demand scenario consistent with CCC recommendations. Under this scenario demand increases by around 9% by 2020 and then more rapidly to 2030 when it is around 30% higher than demand in 2010.

This analysis shows that both packages two and three are able to deliver sufficient low-carbon investment so the grid carbon intensity level of 100gCO_2/KWh in 2030 is achieved.

Net welfare under the CfD package is positive under this scenario at £6.6bn (2010 to 2030 real). If the decarbonisation and technology profiles achieved in the premium payments package were identical to the CfD package, the NPV would be £2.5bn. The Government draws the following conclusion from this scenario analysis: the more investment needed to meet the Government's decarbonisation objectives, the more significant the benefits from a reduction in the cost of capital between packages 3 and 2 become. Similarly, if demand were below central expectations, the difference in net welfare is expected to be smaller.

Actions to improve liquidity

30. Liquidity is an important feature of a well functioning market and is important both to the functioning of feed-in tariffs and capacity mechanisms. It is the ability to quickly buy or sell a desired commodity or financial instrument without causing a significant change in its price and without incurring significant transaction costs. A key feature of a liquid market is that it has a large number of buyers and sellers willing to transact at all times, and a liquid market is one which is characterised by a significant volume of individual trades. Liquid markets offer a range of important benefits, including:

- allowing parties to better manage long-term risk and provide long-term price signals about future market development, which inform investment decisions and promote long term security of supply;

- increasing confidence in traded prices (a large number of gas and electricity supply contracts between buyers and sellers are referenced to market prices), which also inform investment decisions; and

- facilitating new entry in generation and supply by allowing new entrants to buy and sell electricity to match their output and customer base with confidence.

31. As discussed in chapters 3 and 4, these benefits are particularly important in the context of the EMR reforms because:

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

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

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

32. Liquidity in the wholesale electricity market is low in comparison with both other commodity markets in GB and electricity markets in a number of other European countries[88]. Analysis by Ofgem has identified low liquidity as one of the most important barriers to entry in GB supply markets. Subsequent investigations have found that existing small and independent suppliers struggle to access the forward products that they need to meet customer demand and manage wholesale market related risks[89].

33. In response to the above findings, in June 2009 Ofgem announced a programme of work to increase liquidity in the wholesale electricity market. Ofgem has urged the industry to take its own actions to improve liquidity, and will is monitoring the developments to see if progress is sufficient. If progress by Spring 2011 is inadequate, Ofgem intends to bring forward measures to improve matters.

34. Ofgem have set out four possible measures to achieve this:

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

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

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[88] Ofgem discussion paper: Liquidity in the GB wholesale energy markets (June 09), http://www.ofgem.gov.uk/MARKETS/WHLMKTS/COMPANDEFF/Documents1/Liquidity%20in%20the%20GB%20wholesale%20energy%20markets.pdf

[89] Liquidity Proposals for the GB wholesale electricity market, Ofgem consultation (2010)

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

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

35. Ofgem have set out their proposals for the next stages of their liquidity work in their open letter[90] published 3rd December. They will:

- align their work on liquidity with wider market developments including EMR;

- continue to develop the detailed design of their options for intervention;

- continue to monitor the market, with a view to publishing their next assessment in Spring 2011; and

- continue to press for further development of a liquid wholesale market.

36. We anticipate that Ofgem will wish to act rapidly to address liquidity to ensure that the market is able to operate as effectively as possible both before and after the introduction of the EMR reforms and that they will set out their proposals approach as part of their assessment in Spring 2011.

Conclusion

37. Based on the analysis undertaken as part of the electricity market reform project, the Government has identified a preferred package of reforms: Package 3. This package consists of:

- a carbon price support mechanism to address the fundamental market failure: the lack of a stable, certain and sufficiently high carbon price to drive investment in the power sector;

- a feed-in tariff with a contract for difference for low-carbon technologies to reflect that on its own the carbon price is unlikely to give the incentives to build the scale of low-carbon generation needed at the pace demanded by the UK's renewable and decarbonisation targets. The modelling indicates it is the most cost-effective way of supporting low-carbon generation investment;

[90] Ofgem open letter: Liquidity in the GB power market update and next steps, 3 December 2010, http://www.ofgem.gov.uk/Pages/MoreInformation.aspx?docid=163&refer=MARKETS/WHLMKTS/COMPANDEFF

- the use of regulation in the form of a targeted emissions performance standard to prevent the construction and operation of new coal-fired power stations, the most carbon intensive form of electricity generation; and

- action to improve the quality of signals for investment in the new flexible capacity needed to ensure continued security of supply as the sector decarbonises. This would be through a combination of improving the incentives in the existing energy market, combined with a targeted capacity mechanism designed to ensure sufficient generation is available to meet demand.

38. Implementing reforms to cash out and liquidity is the responsibility of the regulator and Ofgem has already begun work. The Government is keen for this work to be progressed in parallel with the wider Electricity Market Reform because it should bring benefits to consumers in its own right, as well as supporting market reforms. It is also important to ensure that these reforms are taken together as a whole because they interact. For example, measures to improve liquidity will offset some of the risks of cash out reforms.

39. However, the Government recognises that there remain some outstanding implementation and design issues. Therefore, if these cannot be resolved the Government will consider alternatives. As such the Government considers package 2, where a system of premium FITs replaces the CfD to be a credible alternative, Based on the evidence to date, the Government is unattracted to introducing a package that relies solely on the carbon price to drive investment (Package 1) or the introduction of a fixed FIT system (Package 4).

Question 26: Do you agree with the Government's preferred package of options (carbon price support, feed-in tariff (CfD or premium), emission performance standard, peak capacity tender)? Why?

Question 27: What are your views on the alternative package that Government has described?

Question 28: Will the proposed package of options have wider impacts on the electricity system that have not been identified in this document, for example on electricity networks?

Question 29: How do you see the different elements of the preferred package interacting? Are these interactions different for other packages?

Chapter 6 – Implementation Issues

Chapter Summary:

Reforming the electricity market gives rise to significant implementation questions. These range from defining the capabilities we will require in the bodies that should be tasked with various roles in the market, through to the detailed parameters of how the proposed reform mechanisms will function.

Key principles and design questions will need to be addressed for each of the policy mechanisms by the time of the White Paper in 2011, informed by the findings of this consultation. Specific policy attributes to be considered include contract lengths, alignment of incentives and choice of market indices for reference, as well as the approach to price setting. The latter raises questions regarding the use of auctions or tenders for the FIT and targeted capacity mechanism.

Government is aware that it is important to ensure a smooth transition. The aim is that transition will occur on a timetable to ensure the UK remains on course to meet its renewable and decarbonisation targets, minimises uncertainty for investors and smoothly transitions responsibilities across bodies. There will be necessary changes to the Renewables Obligation during transition to a new market framework. The Government recognises that it is equally important that the system honours existing commitments.

The Government intends to take final decisions for the reform package by the time of the White Paper in 2011. Following the White Paper, and in parallel to taking the necessary legislative powers, the more detailed aspects can be developed and then ultimately codified with the intention of the new scheme taking effect around 2013/2014, although exact timings cannot be determined in advance of decisions on future Legislative Programmes.

1. The implementation questions range from defining the capabilities we will require in the bodies that should be tasked with various roles in the market through to the detailed parameters of how the proposed reform mechanisms will function.

2. Efforts to develop an effective implementation approach fall into three broad categories:

- **instrument design:** how the proposed policy instruments function and are to be structured;

- **institutional capability and framework:** identifying the skills needed for the timely introduction and efficient operation of the mechanisms and which institutions are best placed to administer the market in future.

- **ensuring a smooth transition:** how policy development and institutional change can be managed in order to minimise disruption for market participants.

3. Work on the carbon price support mechanism is led by HM Treasury, and is subject to a separate consultation which includes a consideration of how the mechanism would be implemented in practice[91]. The implementation of that mechanism will be considered separately. This consultation is seeking views on the remaining three elements of the preferred reform package.

Instrument design

The role of auctions in setting feed-in tariff support levels

4. A major challenge with any feed-in tariff system is setting the correct level of support for technologies or projects. Support should be sufficient to provide an economic return that is high enough for generators to invest in low-carbon projects but not so high that generators earn unnecessarily high returns at the expense of consumers.

5. The level of low-carbon revenue support can be set by either of the following:

- **government:** this is how support levels under the Renewables Obligation are set. In practice, this involves collecting cost and deployment data and modelling the electricity market. A range of factors are considered, including impact on consumers and contribution to our targets.

- an **auction/tender**: a well-designed auction is capable of revealing bidders' underlying costs to Government, provided there is sufficient competitive tension.

6. When the government sets the support level it takes account of deployment costs, projected income and having regard to the need to meet our legally binding targets.

7. The current process for setting banding levels for support under the Renewables Obligation could be used to set the strike price under a CfD. This involves Government assessing costs and deployment potential (usually through the use of independent consultants), and modelling this alongside expected income (i.e. electricity price, gate fees and other support such as Levy Exemption Certificates) and a number of other factors, such as the impact an individual technology is expected to have on achieving our targets.

[91] http://www.hm-treasury.gov.uk/consult_index.htm

8. This can be a complex way to set support levels, and relies on accurate data. It does not have the price revelation properties of an auction based system, and could lead to over or under-compensation. However, it has the key advantage that we could implement it with relative ease, and we have a track record in setting support levels for renewable technologies in this way.

9. The Government is attracted to a greater use of auctioning as a mechanism to set the level of feed-in tariff support, regardless of the specific model for FIT chosen in the White Paper next year. The price discovery characteristics of an auction should enable financial support to be set at a level just high enough to lead to deployment but not high enough to lead to excessive profits, with bids driven down by competition.

10. However, adopting an auction-based approach would require Government to determine what share of the electricity mix should be low-carbon and may require Government to have a view on the breakdown of technologies within the low-carbon mix. Leaving decisions on technology choice to individual investors – who are directly exposed to the risk of making poor decisions, could lead to a lower-cost and lower-risk technology mix.

11. There are a number of issues to consider before introducing auctioning as the mechanism to set the support level for any feed-in tariff system. Realising the potential benefits of an auction depends on its specific design. During the consultation process the Government will consider whether and how an auction could be designed for the low-carbon generating sector. The issues under consideration include:

- scope for competitive tension in any auctions given that sites, technologies (also if first-of-a-kind), and developers' levels of readiness may differ significantly;

- the ability of market participants to realistically price and bid for new technologies and/or technologies that have not been deployed in the UK for many years;

- the risks of gaming of any auction. For example risk may arise where there are limited allowable sites for low-carbon generation (for example nuclear and Round Three offshore wind);

- the advantages and disadvantages of generic auctions for low-carbon technology compared with technology-specific auctions;

- the practicalities of running project-specific auctions, or auctions to establish the value of support for technology classes;

- implementation issues and the impact on the renewables targets and low-carbon investment plans because successful auction design requires significant preparation;

- potential impact of auction design on incentives and barriers to new entry to the GB electricity market;

- transaction costs associated with participating in an auction. This could be a particular issue for some technologies where the project size is smaller and there are more individual generators. If the costs and complexity of participation are high, then generators may choose not to participate; and

- empty auction room risk – in the absence of an obligation to build there is no requirement for any firm to participate in an auction. If investors view Government's ambitions as impractical there is a risk they choose not to participate or only bid requiring high levels of support.

12. Government is interested in supporting the market to bring forward a portfolio of low-carbon technologies because a diverse technology mix is a prudent approach in a world where future technology costs are unknown and uncertain. Having a diverse technology mix will avoid dependence on a single technology which may have significant flaws or be more expensive than first expected. A diverse technology mix will enable the country to benefit from cost developments in technologies which might become much more cost-competitive over time such as certain renewables technologies.

13. Currently GB utilities have an incentive to invest in a diverse technology mix as a hedge against risks such as technology failure or unexpected changes in deployment or fuel costs. In an auction-based approach, where Government determines the amount of low-carbon generation for the electricity system, rather than leaving the decision to the market, the question of ensuring a diverse mix requires more direct intervention. In such a system the Government would need to decide whether to run:

- a single auction for all technologies; or

- separate auctions for different technologies

14. Having one auction for all low-carbon technologies would maximise competition between technologies, allowing investors (who are driven by maximising the return on their investments) to determine the most cost-effective low-carbon technologies. However, this could on the other hand lead to a "winner takes all" outcome where the current lowest cost technology would win all the bids and dominate the technology mix. This would not be good for encouraging early stage, high cost technologies such as renewables.

15. Having technology-specific auctions would enable different tariffs to be set for different technologies but could lead to insufficient competition (not enough bidders) and would probably entail the Government having to specify how much capacity from each technology was wanted (i.e. how many GW of onshore wind, offshore wind, nuclear etc).

16. One way to provide differentiation in support for individual low-carbon technologies within an auction approach, and replicate the benefits of allowing investors to choose the technology mix, could be to have a technology neutral auction for a single tariff level for all low-carbon generation and then to offer technology specific premiums on top to early stage technologies with higher costs such as offshore wind. This would give additional revenue certainty to the lower cost and more mature low-carbon technologies but would allow Government to recognise that innovation in earlier stage, higher-cost technologies is a legitimate objective in its own right.

Box 12: Auctions for feed-in tariffs

Offshore wind tenders in Denmark

The Danish Energy Authority has run four auctions for three offshore wind sites (one was re-tendered). The principal criterion determining allocation was the amount of the feed-in price per kWh of electricity produced that applicants requested in order to carry out the project.

A detailed seabed assessment is undertaken prior to bidding by the System Operator, who is also responsible for providing grid connection, which reduces risk to the generator significantly. In order to minimise the risk of non-delivery bidders undergo rigorous pre-qualification procedures to assess their financial viability, and fines are imposed for time overruns or withdrawals from projects.

Offshore wind tenders in the Netherlands

The Netherlands operate tender based procurements for a FIT with CfD for offshore wind. Winners are determined on the basis of the tariff level they propose. Bidders need to provide financial guarantees, and a fixed penalty is applied for non-delivery or late delivery.

Non Fossil Fuel Obligation

The NFFO is an example of where tenders have been used in the UK renewables industry. It illustrates how auctions can deliver efficiencies, but also that scheme design is critical for successful deployment.

The Non-Fossil Fuel Levy was established with the purpose of supporting nuclear and stimulating renewable energy, requiring electricity companies to contract for certain amounts of generating capacity from renewable sources.

Renewable project developers could bid for the level of fixed feed-in tariff at which they would be prepared to build and operate. The auctions were run by the electricity regulator on a technology banded basis, stacking the offers in cost order and setting the strike price to give an appropriate quantity at a reasonable price. All generators offering below the strike price for their technology received a power purchase agreement for the order duration at the strike price.

In practice, the effectiveness of the orders in terms of new generation development was mixed. The tender rules meant that developers did not start the planning consent process until after the tender had concluded and many failed to secure consent. No penalties were established for failure to deliver, so many more projects were not built whether due to cost estimates proving optimistic, finance being difficult to secure or technology shortcomings. Critics also cite a “winners’ curse” whereby bidders tended to be optimistic and subsequently regretted their bid, but payment at the strike price for the early Orders meant that this effect would have been marginal.

Tendering for, and using, targeted resource

17. Chapter 4 highlights the risk of market distortion arising from a targeted capacity mechanism and the effect this mechanism can have on peak prices, as well as the 'slippery slope' effect. During the consultation process the Government will consider whether and how it is possible to mitigate these and other impacts effectively. Issues that need to be considered include:

- What types of plant would be eligible to enter the contract:
    - existing generation;
    - that which would otherwise close;
    - new or upgraded plant.

  How could these be defined?

- The risks of investors not building with the expectation of then getting a tender instead. How could the mechanism be designed to minimise this?

- Whether it is desirable or possible to use the 'economic dispatch' model rather than the 'last-resort' model, including whether the necessary cash out reform is needed

- The interactions with the procurement of reserves for balancing purposes (both STOR and through the balancing mechanism) and any changes to these arrangements that result from forthcoming review.

- Interactions with EU markets in particular in terms of impact on market coupling.

- Impact on and benefits for DSR, energy efficiency, storage, interconnection and distributed generation. Are further measures also needed in these areas?

Institutional capability and framework

18. Any of the packages proposed in chapter 5 would result in changes to the roles and responsibilities of the organisations charged with ensuring the smooth functioning of the electricity market and in particular the preferred package will create a range of new responsibilities and change a number of existing functions. Between now and the White Paper, the Government will define these changes and seek a future institutional framework which will ensure continued functioning of the electricity markets.

19. The Government is undertaking two other reviews which could have an impact on the future institutional framework:

- **Delivery Landscape review:** the Annual Energy Statement published earlier this year set out that the Government would consider how best to streamline the existing delivery channels for energy and climate change policy. The findings of this work will be published next year. The Government is working to ensure any proposals for changing the delivery landscape is aligned with the delivery requirements of the proposed market reforms covered in this consultation document;

- **Ofgem Review:** this review of the independent economic regulator was launched in July 2010 and the Government intends to report its findings in 2011, alongside the White Paper. This review focuses on Ofgem's role as an independent economic regulator. It was launched in July 2010 and the Government intends to report its findings in 2011, alongside the White Paper. The Government remains committed to ensuring that Great Britain has an effective energy regulatory framework overseen by an independent regulator and, following a call for evidence, the Review is focusing on the clarity of the role of the regulator and, in particular, how their role should relate to that of Government and other bodies in the regulatory landscape.

20. The Government's approach will be to define the set of activities and capabilities required in the reformed electricity market and determine the arrangement of institutions best placed to undertake these activities. In particular, care would be taken to define the required nature and future role of the System Operator. The Government will seek to create an institutional framework that is cost-efficient, effective and once implemented, creates stability for market participants and opportunity for new entrants.

Ensuring a smooth transition

21. The Government recognises that as a result of its commitment to reform the electricity market, there is uncertainty in the market which is preventing participants from taking decisions to invest in new low-carbon electricity generation. The Government is committed to publishing conclusions to this work in a White Paper next Spring and a swift implementation of all reforms.

22. In particular, the Government will seek to:

- Ensure that implementation proceeds on a timetable that enables investors to bring forward the renewable, coal CCS, gas and nuclear projects they are proposing so that UK maintains secure of supplies of electricity and remains on course to meet its renewable and decarbonisation targets;

- Minimises uncertainty for investors during the transition; and

- Smoothly transitions responsibilities across bodies, where responsibilities are reallocated.

Implementation Timeline

23. The Government is committed, subject to Parliamentary time and the complexity of the design issues, to the following implementation timeline for the reform of the electricity market:

- Late Spring 2011 – Publication of White Paper with final reform proposals;

- 2011 onwards – Aim to establish new powers in Primary Legislation; exact timings cannot be determined in advance of decisions on future Legislative Programmes; and

- 2013/14 – Secondary legislation in place, codes and licenses modified and new schemes take effect.

Legal and regulatory factors

24. The options proposed will be taken forward in accordance with the Government's obligations under EU law, including the terms of any necessary state aid approvals.

25. In addition to EU law, the options proposed may interact with UK law.

26. The Government also recognises the need to consider the regulation and treatment of proposed financial instruments under prevailing financial and accounting regulations. The Government will consider these factors as it proceeds with the Electricity Market Reform measures.

Devolution

27. Since April 2005 under the Energy Act 2004, the British Electricity Trading and Transmission Arrangements (BETTA) have covered England, Wales and Scotland. Certain powers have been executively devolved to Scotland, notably some aspects of the Renewables Obligation and the granting of consent to large electricity generation under Section 36 of the Electricity Act 1989. The generation, supply and distribution of electricity in Northern Ireland are fully devolved and operate under the Single Electricity Market of the Island of Ireland.

28. The Renewables Obligation (RO), the current support mechanism for large scale renewable electricity generation in UK, is executively devolved for Scotland and fully devolved to Northern Ireland. The introduction and orderly transition to a new mechanism, will require detailed discussion with the Devolved Administrations depending on its territorial and technological scope. The Government is committed to working closely with the Devolved Administrations to ensure the investment framework for low-carbon generation across the UK remains attractive.

29. Scotland in particular has a leading role in the production of renewable electricity. In 2009, according to Energy Trends, 48% of UK renewable

generating capacity was located in Scotland, while the latest RO Annual Report shows 35% of renewable electricity from Scottish generators.

Market reform and the Renewables Obligation

30. Reforming the electricity market will necessitate changes to the Renewables Obligation, during transition to the new market framework. The Government recognises that investors are making decisions now on the basis of the support available under the RO mechanism and will require clarity about when the new system will be introduced and how existing investment plans will be affected. Equally important are those investment decisions which have already been taken on the basis of support available under the RO.

31. While the detail of any transition will need to be developed in more detail, once final decisions have been taken on the final proposals for market reform, there are several principles which will underpin the transition process:

- **Grandfathering:** the Government recognises the importance of honouring commitments given to provide generators with a particular level of support, as part of maintaining investor confidence.

- **Accelerating the RO banding review:** bands for renewable technologies are reviewed at regular intervals to ensure that as innovations come in and market conditions within sectors change and evolve, developers continue to receive the correct level of support necessary to maintain investment in the renewables industry. Speeding up the current review this will give earlier notice of support levels for projects that will accredit between 1 April 2013 and 31 March 2017; the Government is committed to consulting on bands in Summer 2011, with a Government response in Autumn 2011, to give developers clarity of the support available under the existing regime while the new legislative powers are taken for the proposed FIT regime to be introduced.

- **Maintaining the RO until 2017 for new projects**: this would allow those developers who are making initial plans now under the RO to avoid disruption and continue with projects while the new arrangements are being developed. The Government is interested in hearing views on whether to give developers a choice over which scheme to register with to receive support;

- **Working with the devolved administrations**: the Government, and the Devolved Administrations are committed to working together to create a transparent investment climate for developers across the UK; and

- **Fuelled renewables**: as part of this transition, the Government will also be considering the implications for those technologies which are not currently grandfathered in England and Wales, such as co-firing of biomass, bioliquids, energy crops and CHP. We continue to apply sustainability standards to biomass and bioliquids under the new support framework.

Question 30: What do you think are the main implementation risks for the Government's preferred package? Are these risks different for the other packages being considered?

Question 31: Do you have views on the role that auctions or tenders can play in setting the price for a feed-in tariff, compared to administratively determined support levels?

- **Can auctions or tenders deliver competitive market prices that appropriately reflect the risks and uncertainties of new or emerging technologies?**

- **Should auctions, tenders or the administrative approach to setting levels be technology neutral or technology specific?**

- **How should the different costs of each technology be reflected? Should there be a single contract for difference on the electricity price for all low-carbon and a series of technology different premiums on top?**

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

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

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

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

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

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

ANNEX A Renewables: Maintaining investor confidence during the implementation of the Government's new market mechanism

1. Renewable electricity is key to our low-carbon energy future and is a vital component of the UK's diverse energy mix. The UK has some of the best natural renewable energy resources in Europe, and we recognise the importance of maintaining industry confidence and creating stable conditions for investment, in order to deploy renewable electricity to the levels needed to meet our 2020 targets and beyond.

2. Until 2017 we propose to support renewable investments using the following measures:

- Banding Review accelerated to give early certainty on RO tariff levels

- New support mechanism introduced in 2013 or 2014.

- RO maintained so schemes can accredit under the RO until 2017.

- Seeking views on whether to offer a choice of support mechanisms up to April 2017.

- Eligible Schemes accrediting after 31 March 2017 will receive support under the new scheme.

3. The current Renewables Obligation (RO) is designed to provide up to 20 years' support for large scale renewable electricity projects, and will run until 2037. We propose that the RO will remain open until 31 March 2017, the point at which the length of support offered begins to reduce.

4. This document consults on options for the future structure of the UK electricity market, and within this, how we will support renewable energy. Government recognises that there is a significant existing Renewable Electricity investor community, and we aim to prevent a hiatus in renewables investment. We are therefore seeking industry views on the best means to transition to a new scheme.

5. After 31 March 2017 our aim is that projects receiving support under the RO should continue to receive support in line with our current grandfathering

policy. The RO system would be 'vintaged' to ensure this. We are consulting on the best means to 'vintage' the RO.

Renewables support up to 2017

Banding Review Timetable

6. On 10 December 2010 we announced a new, faster timetable for the Renewables Obligation Banding Review, which will give earlier notice of support levels for generation that will accredit between 1 April 2013 and 31 March 2017 (and for those technologies that are not currently grandfathered).

7. We will consult on RO Banding Levels for 2013-2017 from Summer 2011. The full timetable for the new Banding Review will be:

February 2011	Completed review of costs and potential deployment
May 2011	Completed modelling of different Banding Scenarios
Summer 2011	Announce Banding Scenario to industry for consultation
Autumn 2011	Government response
April 2013	New bands brought into force

Maintaining the Banded RO

8. As stated in the Coalition Agreement, we will maintain a banded RO system. We propose that new renewable electricity generating stations will be able to accredit under the RO until 31 March 2017, the point at which the length of support available under the RO would otherwise have begun to decline.

9. We are consulting on a new mechanism to support all low-carbon. The Government's ambition is to introduce a new feed-in tariff for low-carbon in 2013/14 subject to parliamentary time. This means that projects making the decision to invest after the new scheme is introduced will know what form of support they should receive should they accredit after 31 March 2017.

10. Accreditation under the RO will be available until 31 March 2017. Subject to industry views, the Government proposes to either:

    a. Accredit all new renewable electricity capacity before 1 April 2017 in the RO system

    or

    b. Offer a choice of the RO or the new support mechanism for new renewable electricity capacity accrediting after the introduction of EMR in 2013/14, but before 1 April 2017

11. We will consult on the indication of RO Banding Levels for April 2013 by Summer 2011, and confirm by Government Response in Autumn 2011.

RO only until 2017

12. If we accredited all renewable electricity capacity under the RO until 31 March 2017, and under the new EMR mechanism thereafter, this would mean that there was only ever one support mechanism for new renewable electricity available at a single time.

Choice of RO or new system between 2013 and 2017

13. Offering a choice of mechanism might reassure investors who are considering developing projects before tariff levels under the new system are known. Those investors who would only invest under a new scheme which gave more revenue certainty would have the opportunity to do so at an earlier stage.

14. There would be additional administrative complexity in having two mechanisms open to accreditation simultaneously, but having the option may provide additional certainty, and we would welcome views on this.

'Vintaging' the RO in 2017

15. We propose to close the RO to new accreditation from 1 April 2017. All projects accredited under the RO would receive their full 20 years' support (subject to the end dates set in the RO). Therefore, the entire RO system would be 'vintaged' from 1 April 2017.

16. 'Vintaging' the RO system would effectively mean that it would no longer be open to accreditation for new stations. The RO would continue to operate, but support levels in terms of number of ROCs will not change (subject to a decision on grandfathering technologies, as discussed below).

17. The closure of the RO to new investment 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.

Technologies not currently grandfathered

18. Some technologies are not currently grandfathered under the RO – co-firing, bioliquids, CHP, and energy crops. We are now considering whether bioliquids produced from wastes and advanced conversion technologies should be grandfathered.

19. Grandfathering is the policy intention to maintain a fixed level of support for the full lifetime of a generating station's eligibility for the RO, from the point of accreditation. In 2008, following consultation on banding and grandfathering, grandfathering was introduced for all 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. In particular:

- Generators entering the market in different years could receive different levels of support, yet would compete for the same fuel stock, thereby potentially distorting the market (as one would be able to pay more than the other).

- Equally, if fuel prices went down, existing generators would be over-compensated at the cost to the consumer; whilst if fuel prices went up the projects would no longer be economic.

20. Following representations from a number of developers, suggesting that the lack of grandfathering meant that lenders and equity providers were withholding investment for biomass plants, the previous administration launched a consultation in March 2010. Working extensively with industry and the finance community to assess the evidence we concluded that a greater degree of revenue certainty was needed to bring biomass forward and in the Government Response to Biomass Grandfathering the current administration set out our decision to:

- Grandfather Anaerobic Digestion, Advanced Conversion Technologies, Dedicated Biomass using solid biomass or biogas and Energy from Waste;

- Not to grandfather Bioliquids, Energy Crop uplift or CHP, but to make a more detailed assessment of bioliquids using wastes and advanced conversion technologies; and

- To continue our policy not to grandfather co-firing.

21. We will consider whether the remaining technologies and feedstocks should be grandfathered by 2017. There is therefore a risk that grandfathering them at the support levels existing at 1 April 2013 for the remainder of their lifetimes may over- or under-compensate those technologies. If we do not grandfather them, there is a risk that investors may be reluctant to invest.

22. In the event of over-compensation this would mean that the value for money of the RO is reduced and consumers pay too much for generation from these technologies. In the event of under-compensation this would mean that those

technologies are not sufficiently incentivised to generate. This could have implications for renewables deployment to 2020 if generation does not come forward as expected.

23. In the event that we chose not to grandfather some or all of the technologies mentioned above, there would be a requirement to periodically review their level of support by way of scheduled Banding Reviews post 1 April 2017. On the current expected schedule we would carry out a banding review for existing installations in these technologies for support they receive from 1 April 2017 to 31 March 2021, and at four-yearly intervals thereafter.

24. We would be grateful for views on these options.

Devolved Administrations

25. Currently the RO schemes for England & Wales, Northern Ireland and Scotland all operate in unison. While there are some minor differences in support levels, all three obligations are implemented in the same way and the buyout funds are unified.

26. Government policy on support for renewables is executively devolved to Scotland and fully devolved to Northern Ireland. Therefore, they have control over their RO mechanisms, and can decide whether to follow the England & Wales mechanism in its choice of transition option and closing to new accreditation from 1 April 2017.

27. Scottish Ministers have publicly stated their support for the current RO system, but will consider their position on the wider EMR proposals. The extent of any new support scheme for low-carbon as regards Scotland and Northern Ireland will be subject to discussions between UK and Scottish and Northern Irish Ministers, and to the final design of the new scheme itself.

28. Government recognises the benefits of a unified system that provides ROC price stability and a fair distribution of costs across UK consumers. In the event that Devolved administrations decided to pursue a separate policy, we would need to consider the implications of this for the operation of the RO going forward. Further details will be in the Government's White Paper in Spring.

Devolved Administrations: which technologies are grandfathered

29. As the RO is a devolved policy, Devolved Administrations have authority over which technologies are grandfathered in their current system. In England and Wales co-firing, bioliquids, CHP, and energy crops are not grandfathered. In Scotland, grandfathering for biomass and waste technologies is subject to a Scottish Government consultation taking place this autumn.

30. In the event that the Devolved Administrations opted to close down the RO as we propose for England and Wales, they will have the further option as to

whether to grandfather the technologies in the same way as proposed for England and Wales.

Calculating the Obligation in the Grandfathered System

31. As the grandfathered RO continues to operate it would be necessary to continue to set the Obligation level.

32. The Obligation level for the RO is currently set with reference to two Calculations, A and B.

33. Calculation A sets the Obligation level by using the fixed targets contained in Schedule 1 of the Renewables Obligation Order 2009 (rising to 0.154 ROCs/MWH in 2015/16), applied to DECC projections of the expected licensed supply level.

34. Calculation B involves the Secretary of State for Energy and Climate Change estimating the amount of ROCs which are likely to be issued during the Obligation Period being calculated, and then adding 10% 'headroom'. The larger of the two results for A and B determines the Obligation level.

35. While we could continue to carry out these two calculations, after 2015/16 the fixed targets are flat at 15.4%. Under the current system it is expected that in 2016/17 the RO will be set by Calculation B as the level of generation will be higher than 15.4% and will continue to increase until at least 31 March 2017. However, this is uncertain and depends on the amount of new renewables capacity that comes forward between now and then. If Calculation A is lower than Calculation B in 2017/18, then we would expect Calculation A to continue to be lower than Calculation B from that point, on until significant amounts of capacity start to leave the RO as it decommissions or reaches the 20-year limit on support.

36. There are therefore a number of options for calculating the obligation for a grandfathered RO:

Continue using both calculations

37. Under this option, Government could extend the fixed targets beyond 2015/16 and continue to use both Calculations to set the obligation going forward.

38. However, following the expected level of decline following 2027, the fixed targets would become substantially higher than the level of capacity, increasing the ROC price, but without the potential for it to attract new investment, thus providing unnecessary subsidy.

From 2017/18 use Calculation B – 'Headroom' - Only

39. Calculation B would be more likely to allow us to take account of the decline in the amount of capacity as it occurs after 2027. However, retaining Calculation

B would require continued resource in DECC to carry out the annual calculations and publication of the obligation level.

40. It also risks the obligation being set too high or too low due to plant retiring before the end of its 20 years' support, or because of flawed assumptions about the amount of capacity likely to come forward and the load factors for that year. Too high would mean that excess rents were paid, too low and the ROC price might crash with the consequent effects on investment in generation accredited under the RO. This risk exists currently but may be exacerbated as the size of the obligation shrinks post 2027.

41. Industry have also expressed their ongoing concern that they need as much clarity on the obligation level as early as possible.

Move to a 'Fixed ROC' system

42. An alternative to the transition process outlined above would be to change the existing RO to a 'Fixed ROC' system at the next banding review implementation date.

43. This would involve fixing the price of a ROC and requiring Ofgem (or another delivery agent) to buy the ROCs, funded through a levy on energy suppliers. The Fixed ROC scheme would then, as outlined above, remain open to new accreditation until 1 April 2017 when it would close and be replaced by the new scheme.

44. Introducing a Fixed ROC system would mean that the scheme no longer operated through placing an obligation on energy suppliers. This would remove the requirement to carry out an annual obligation-setting exercise and need for a buy-out mechanism with associated revenue recycling. The reformed scheme would give generators a guaranteed price for the ROC through to 2037, indexed to inflation.

45. There would be a number of implementation issues, for example the impact on current Power Purchase Agreements, the impact on suppliers in paying for a levy which would need to be paid more frequently than annually. We would be grateful for any views on this. We would also need to consider the potential impact of this option on the public finances before taking it forward.

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

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

Question 36: We propose that accreditation under the RO would remain open until 31 March 2017. The Government's ambition is to introduce the new FIT for

low-carbon in 2013/14 (subject to Parliamentary time). Which of these options do you favour:

- **All new renewable electricity capacity accrediting before 1 April 2017 accredits under the RO;**

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

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

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

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

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

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

- **Continue using both target and headroom**

- **Use Calculation B (Headroom) only from 2017**

- **Fix the price of a ROC for existing and new generation**