Title: Electricity Market Reform – options for ensuring electricity security of supply and promoting investment in low-carbon generation	
Lead department or agency: DECC	**IA No:**
	Date: 12 July 2011
Other departments or agencies:	**Stage:** Final
	Source of intervention: Domestic
	Type of measure: Primary legislation
	Contact for enquiries: Paro Konar

Summary: Intervention and Options

What is the problem under consideration? Why is Government intervention necessary?

This Impact Assessment considers the impacts of measures to reduce the risks to future security of electricity supply and promote investment in low-carbon generation, while minimising costs to consumers. Current electricity market arrangements are not likely to deliver the required scale or pace of investment in low-carbon generation. Reasons include cost characteristics of low-carbon capacity (high capital cost and low operating cost) which means that it faces greater exposure to wholesale price risk than conventional fossil fuel capacity, which has a natural hedge given its price setting role. It is also considered that the carbon price is too low and its future level too uncertain to mitigate the risks associated with low-carbon investment. Our analysis also suggests that there are a number of market imperfections that are likely to pose risks to future levels of electricity security of supply. These effects are likely to be exacerbated when there are significant amounts of low-carbon intermittent generation.

What are the policy objectives and the intended effects?

The three primary policy objectives are to reform the electricity market arrangements to: ensure security of supply; drive the decarbonisation of our electricity generation; and minimise costs to the consumer. These reforms should support delivery of DECC's other objective of the 2020 renewables target. The intended effects are that sufficient generation and demand side resources will be available to ensure that supply and demand balance continues be met and there will be sufficient investment in low-carbon generation to allow decarbonisation goals to be met.

What policy options have been considered, including any alternatives to regulation? Please justify preferred option (further details in Evidence Base)

The overall policy is assessed as a package. The policy options considered for driving investment in low-carbon generation are (a) contracts for difference (FIT CFD) feed in tariff and (b) premium feed in tariff. These have been combined with measures to ensure electricity security of supply with options on (c) a targeted mechanism and (d) a market wide mechanism (both of these options are set out for consultation in the White Paper). For the purposes of this Impact Assessment, we have analysed the impacts of a Strategic Reserve form of targeted mechanism and a Reliability Market form of a market wide mechanism.

Will the policy be reviewed? It will be reviewed. **If applicable, set review date:** Month / Year **What is the basis for this review?** PIR **If applicable, set sunset clause date:** Month / Year	
Are there arrangements in place that will allow a systematic collection of monitoring information for future policy review?	Yes/No

Ministerial Sign-off

I have read the Impact Assessment and I am satisfied that, (a) it represents a fair and reasonable view of the expected costs, benefits and impact of the policy, and (b) the benefits justify the costs.

Signed by the responsible Minister: Date:12 July 2011

Summary: Analysis and Evidence Policy Option 1

"Do nothing" – maintain Renewables Obligation for incentivising investment in renewable electricity generation. No further policies to incentivise investment in other low-carbon other than current policies like the Carbon Price Floor.

Price Base Year 2009	PV Base Year 2010	Time Period Years 20	Net Benefit (Present Value (PV)) (£m)		
			Low:	High:	Best Estimate:

COSTS (£m)	Total Transition (Constant Price)	Years	Average Annual (excl. Transition) (Constant Price)	Total Cost (Present Value)
Low				
High				
Best Estimate				

Description and scale of key monetised costs by 'main affected groups'

This option is the baseline against which the other options for reform are compared so there are no costs or benefits.

Other key non-monetised costs by 'main affected groups'

Under this option, the electricity system achieves a carbon intensity of around 170gCO_2/kWh in 2030. This is considered to be insufficient to put the UK on a path to meeting its long-term decarbonisation objectives. For instance, the Committee on Climate Change has recommended 50g/kWh by 2030. The Government has not yet set a decarbonisation target beyond the third carbon budget period (2018-2022).

BENEFITS (£m)	Total Transition (Constant Price)	Years	Average Annual (excl. Transition) (Constant Price)	Total Benefit (Present Value)
Low				
High				
Best Estimate				

Description and scale of key monetised benefits by 'main affected groups'

n/a

Other key non-monetised benefits by 'main affected groups'

Under this option, there is reduced risk of investment hiatus for renewable technologies as investors are familiar with the current Renewables Obligation.

Key assumptions/sensitivities/risks **Discount rate (%)** 3.5

n/a

Direct impact on business (Equivalent Annual) (£m):			In scope of OIOO	Measure Qualifies as
Costs: **n/a**	**Benefits**: **n/a**	**Net**: **n/a**	Yes/No	IN/OUT

Summary: Analysis and Evidence Policy Option 2

Contracts for Difference (FiT CfD) Feed in Tariff on the wholesale electricity price combined with a Strategic Reserve Capacity Mechanism.

Price Base Year 2009	PV Base Year 2010	Time Period Years 20	Net Benefit (Present Value (PV)) (£m)		
			Low: -164	High: 11,766	Best Estimate: 9,600

COSTS (£m)	Total Transition (Constant Price)	Years	Average Annual (excl. Transition) (Constant Price)	Total Cost (Present Value)
Low				
High				
Best Estimate				16,230

Description and scale of key monetised costs by 'main affected groups'

Capital costs for the electricity generation sector increase by £16.1bn compared to the baseline due to higher capital costs of low-carbon technologies compared to conventional fossil fuel plant.
Some relatively minor resource costs associated with building/maintaining the additional capacity which is part of the Strategic Reserve (SR). There will be administrative costs to business and costs associated with the setting up and running of the new institutional arrangements – a central estimate of this is £130million .

Other key non-monetised costs by 'main affected groups'

Compared to PFiTs, CfDs are more complex. The success of CfDs depend on the successful implementation, which depends on decisions made on the institutions to administer the instrument and the process to determine the support levels. Further details of the non-monetised costs can be obtained in Section 3.

BENEFITS (£m)	Total Transition (Constant Price)	Years	Average Annual (excl. Transition) (Constant Price)	Total Benefit (Present Value)
Low				
High				
Best Estimate				25,800

Description and scale of key monetised benefits by 'main affected groups'

There will be £8.9bn of savings to the power sector from it having to buy fewer EU ETS allowances. In addition to this, the generation cost of electricity plant will be around £16.2bn lower due to the lower running cost of low-carbon plant. There will also be benefits related to improvements in air quality amounting to around £643m.

Other key non-monetised benefits by 'main affected groups'

FiT CfD is more effective in bringing forward investment in low-carbon generation and encouraging additional investment in the sector. In addition, Power Purchase Agreements, should become cheaper for generators in the future, making the FiT CfD a more efficient support instrument. The benefits of innovation are not included in the NPV. Further details of the non-monetised benefits can be obtained in Section 3.

Key assumptions/sensitivities/risks **Discount rate (%)** 3.5

The period considered is only up to 2030, therefore the analysis does not capture the benefits realised beyond 2030 when carbon prices could rise further.

Valuations of the costs of supply disruption (Value of lost load - VoLL) are highly uncertain. For the purposes of modelling, we have used a VoLL of £10,000/MWh. For appraisal, we have tested the impact of using a VoLL of £30,000/MWh. This, as well as sensitivities on cost of capital, are assessed in sections 3 and 4 but not for the package, and are therefore not included here.
The sensitivities above stem from an assessment under different fossil fuel price assumptions, rather than a range under central assumptions.

Direct impact on business (Equivalent Annual) (£m):			In scope of OIOO	Measure Qualifies as
Costs: 1000	**Benefits**: 1600	**Net**: 600	No	N/A

Summary: Analysis and Evidence Policy Option 3

Premium Feed in Tariff on top of the wholesale electricity price combined with a Strategic Reserve Capacity Mechanism.

Price Base Year 2009	PV Base Year 2010	Time Period Years 20	Net Benefit (Present Value (PV)) (£m)		
			Low: 1,611	High: 7,530	Best Estimate: 7,530

COSTS (£m)	Total Transition (Constant Price)	Years	Average Annual (excl. Transition) (Constant Price)	Total Cost (Present Value)
Low				
High				
Best Estimate				10,730

Description and scale of key monetised costs by 'main affected groups'

Capital costs for the electricity generation sector increase by £10.6bn compared to the baseline due to higher capital costs of low-carbon technologies compared to conventional fossil fuel plant.
Some relatively minor resource costs associated with building/maintaining the additional capacity which is part of the strategic reserve (SR). There will be administrative costs to business and costs associated with the setting up and running of the new institutional arrangements – a central estimate of this is £130million.

Other key non-monetised costs by 'main affected groups'

Not robust to fluctuations in wholesale electricity prices and unlikely to generate the additional capital influx that is required in this sector . Further details of the non-monetised costs can be obtained in Section 3.

BENEFITS (£m)	Total Transition (Constant Price)	Years	Average Annual (excl. Transition) (Constant Price)	Total Benefit (Present Value)
Low				
High				
Best Estimate				18,260

Description and scale of key monetised benefits by 'main affected groups'

There will be £6.2bn of savings to the power sector from it having to buy fewer EU ETS allowances. In addition to this, the generation cost of electricity plant will be around £11.5bn lower due to the lower running cost of low-carbon plant.

Other key non-monetised benefits by 'main affected groups'

As the PFiTs are modelled to be similar to the current system under the RO, and is likely to be easier to implement. Further details of the non-monetised benefits can be obtained in Section 3.

Key assumptions/sensitivities/risks **Discount rate (%)** 3.5

The period considered is only up to 2030, therefore the analysis does not capture the benefits realised beyond 2030 when carbon prices could rise further.
Valuations of the costs of supply disruption (Value of lost load - VoLL) are highly uncertain, For the purposes of modelling, we have used a VoLL of £10,000/MWh. For appraisal, we have tested the impact of using a VoLL of £30,000/MWh. This, as well as sensitivities on cost of capital, are assessed in sections 3 and 4 but not for the package, and are therefore not included here.
The sensitivities above stem from an assessment under different fossil fuel price assumptions, rather than a range under central assumptions.

Direct impact on business (Equivalent Annual) (£m):			In scope of OIOO	Measure Qualifies as
Costs: 300	**Benefits**: 900	**Net**: 600	No	N/A

Summary: Analysis and Evidence Policy Option 4

Feed-in Tariff Contracts for Difference (FiT CfD) on the wholesale electricity price combined with a Reliability Market

Price Base Year 2009	PV Base Year 2010	Time Period Years 20	Net Benefit (Present Value (PV)) (£m)		
			Low:	High:	Best Estimate: 8,800

COSTS (£m)	Total Transition (Constant Price)	Years	Average Annual (excl. Transition) (Constant Price)	Total Cost (Present Value)
Low				
High				
Best Estimate				16,400

Description and scale of key monetised costs by 'main affected groups'

Capital costs for the electricity generation sector increase by £16.3bn compared to the baseline due to higher capital costs of low-carbon technologies compared to conventional fossil fuel plant.
There will be administrative costs to business and costs associated with the setting up and running of the new institutional arrangements – a central estimate of this is £130million.

Other key non-monetised costs by 'main affected groups'

In addition to the modelling of costs and benefits of reliability markets , there has been a detailed qualitative assessment of this option.. These are presented in detail in Section 4.

BENEFITS (£m)	Total Transition (Constant Price)	Years	Average Annual (excl. Transition) (Constant Price)	Total Benefit (Present Value)
Low				
High				
Best Estimate				25,200

Description and scale of key monetised benefits by 'main affected groups'

There will be £9.2bn of savings to the power sector from it having to buy fewer EU ETS allowances. In addition to this, the generation cost of electricity plant will be around £15.9bn lower due to the lower running cost of low-carbon plant.

Other key non-monetised benefits by 'main affected groups'

In addition to the modelling of costs and benefits of reliability markets , there has been a detailed qualitative assessment of this option. These are presented in detail in Section 4.

Key assumptions/sensitivities/risks **Discount rate (%)** 3.5

Valuations of the costs of supply disruption (Value of lost load - VoLL) are highly uncertain. For the purposes of modelling, we have used a VoLL of £10,000/MWh. For appraisal, we have tested the impact of using a VoLL of £30,000/MWh. This, as well as sensitivities on cost of capital, are assessed in sections 3 and 4 but not for the package, and are therefore not included here.

We do not have fossil fuel price sensitivity modelling results for this package, but the difference between the options could be of the same order of magnitude as under Policy Options 2 and 3.

Direct impact on business (Equivalent Annual) (£m):			In scope of OIOO	Measure Qualifies as
Costs: 2,200	**Benefits**: 2,600	**Net**: 400	No	N/A

Summary: Analysis and Evidence Policy Option 5

Premium Feed in Tariff on top of the wholesale electricity price combined with a Reliability Market

Price Base Year 2009	PV Base Year 2010	Time Period Years 20	Net Benefit (Present Value (PV)) (£m)		
			Low:	High:	Best Estimate: 7,700

COSTS (£m)	Total Transition (Constant Price)	Years	Average Annual (excl. Transition) (Constant Price)	Total Cost (Present Value)
Low				
High				
Best Estimate				10,500

Description and scale of key monetised costs by 'main affected groups'

Capital costs for the electricity generation sector increase by £10.4bn compared to the baseline due to higher capital costs of low-carbon technologies compared to conventional fossil fuel plant.
There will be administrative costs to business and costs associated with the setting up and running of the new institutional arrangements – a central estimate of this is £130million.

Other key non-monetised costs by 'main affected groups'

In addition to the modelling of costs and benefits of Strategic Reserve, there has been a detailed qualitative assessment of this option. These are presented in detail in Section 4.

BENEFITS (£m)	Total Transition (Constant Price)	Years	Average Annual (excl. Transition) (Constant Price)	Total Benefit (Present Value)
Low				
High				
Best Estimate				18,200

Description and scale of key monetised benefits by 'main affected groups'

There will be £6.2bn of savings to the power sector from it having to buy fewer EU ETS allowances. In addition to this, the generation cost of electricity plant will be around £11.9bn lower due to the lower running cost of low-carbon plant.

Other key non-monetised benefits by 'main affected groups'

In addition to the modelling of costs and benefits of Strategic Reserve, there has been a detailed qualitative assessment of this option. These are presented in detail in Section 4.

Key assumptions/sensitivities/risks **Discount rate (%)** 3.5

Valuations of the costs of supply disruption (Value of lost load - VoLL) are highly uncertain. For the purposes of modelling, we have used a VoLL of £10,000/MWh. For appraisal, we have tested the impact of using a VoLL of £30,000/MWh. This, as well as sensitivities on cost of capital, are assessed in sections 3 and 4 but not for the package, and are therefore not included here.

We do not have fossil fuel price sensitivity modelling results for this package, but the difference between the options could be of the same order of magnitude as under Policy Options 2 and 3.

Direct impact on business (Equivalent Annual) (£m):			In scope of OIOO	Measure Qualifies as
Costs: 1,700	**Benefits**: 2,600	**Net**: 900	No	N/A

Enforcement, Implementation and Wider Impacts

<table>
<tr><td colspan="3">What is the geographic coverage of the policy/option?</td><td colspan="3">Great Britain</td></tr>
<tr><td colspan="3">From what date will the policy be implemented?</td><td colspan="3">2014</td></tr>
<tr><td colspan="3">Which organisation(s) will enforce the policy?</td><td colspan="3">DECC/TBC post White paper (WP)</td></tr>
<tr><td colspan="3">What is the annual change in enforcement cost (£m)?</td><td colspan="3">N/A (TBC post WP)</td></tr>
<tr><td colspan="3">Does enforcement comply with Hampton principles?</td><td colspan="3">Yes</td></tr>
<tr><td colspan="3">Does implementation go beyond minimum EU requirements?</td><td colspan="3">No</td></tr>
<tr><td colspan="3">What is the CO_2 equivalent change in greenhouse gas emissions?
(Million tonnes CO_2 equivalent)</td><td colspan="2">Traded:
N/A</td><td>Non-traded:
N/A</td></tr>
<tr><td colspan="3">Does the proposal have an impact on competition?</td><td colspan="3">Yes</td></tr>
<tr><td colspan="3">What proportion (%) of Total PV costs/benefits is directly attributable to primary legislation, if applicable?</td><td colspan="2">Costs:
100%</td><td>Benefits:
100%</td></tr>
<tr><td>Distribution of annual cost (%) by organisation size
(excl. Transition) (Constant Price)</td><td>Micro</td><td>< 20</td><td>Small</td><td>Medium</td><td>Large</td></tr>
<tr><td>Are any of these organisations exempt?</td><td>No</td><td>No</td><td>No</td><td>No</td><td>No</td></tr>
</table>

Specific Impact Tests: Checklist

Set out in the table below where information on any SITs undertaken as part of the analysis of the policy options can be found in the evidence base. For guidance on how to complete each test, double-click on the link for the guidance provided by the relevant department.

Please note this checklist is not intended to list each and every statutory consideration that departments should take into account when deciding which policy option to follow. It is the responsibility of departments to make sure that their duties are complied with.

Does your policy option/proposal have an impact on…?	**Impact**	**Page ref within IA**
Statutory equality duties[1] Statutory Equality Duties Impact Test guidance	No	130
Economic impacts		
Competition Competition Assessment Impact Test guidance	Yes	129
Small firms Small Firms Impact Test guidance	No	124
Environmental impacts		
Greenhouse gas assessment Greenhouse Gas Assessment Impact Test guidance	Yes	128-129
Wider environmental issues Wider Environmental Issues Impact Test guidance	Yes	128-129
Social impacts		
Health and well-being Health and Well-being Impact Test guidance	Yes	128-129
Human rights Human Rights Impact Test guidance	No	130
Justice system Justice Impact Test guidance	No	130
Rural proofing Rural Proofing Impact Test guidance	No	119, 130
Sustainable development Sustainable Development Impact Test guidance	Yes	130-131

[1] Race, disability and gender Impact assessments are statutory requirements for relevant policies. Equality statutory requirements will be expanded 2011, once the Equality Bill comes into force. Statutory equality duties part of the Equality Bill apply to GB only. The Toolkit provides advice on statutory equality duties for public authorities with a remit in Northern Ireland.

Evidence Base (for summary sheets)

Section 1 Executive Summary

1.1 Rationale for Intervention

1.1.1 Low levels of investment in low-carbon generation

1. While the UK is on target to reduce its greenhouse gas emissions in 2020 by at least 34% on 1990 levels, in line with carbon budgets and the EU target, the longer-term goals are more challenging. The electricity system needs to be largely decarbonised during the 2030s, particularly if it is to play its part in decarbonising the heat and transport sectors in the 2030s and beyond.
2. This transition to a low-carbon electricity system presents significant challenges for the current market arrangements. Currently, investment in low-carbon plant is higher-risk than investment in conventional fossil fuel-fired plant because low-carbon plant are price takers and have very high up-front investment costs: generators are exposed to risks that they cannot control, such as fossil fuel and carbon prices. This revenue uncertainty is mitigated to some extent by the Renewables Obligation (RO), under which generators of renewable electricity receive an additional revenue stream. However, while the RO could be used to meet the longer-term decarbonisation goals it would not be the most cost-effective way to do so.
3. Under the current system, support has to be high enough to compensate low-carbon generators for this revenue risk, and less investment is coming forward than would otherwise be the case.

1.1.2 Risks to future security of supply

4. The GB electricity market is about to undergo unprecedented changes. While some of these changes can contribute to improving security of supply, such as increased use of Demand Side Response (DSR), some changes also pose increased risks to security of supply – in particular, the retirement of existing plant, and the increased proportion of intermittent and less flexible generation on the system. In this context, a Capacity Mechanism will be needed to ensure 'resource adequacy' - that there is sufficient reliable and diverse capacity to meet demand over longer periods, for example during winter anti-cyclonic conditions.
5. There is a trade-off between the cost of new capacity and security of supply. There is an optimal level of security of supply at which point increased investment in generation capacity becomes more expensive than the value of the marginal reduction in energy demand not being met (known as energy unserved). Estimates of this optimal level are highly uncertain and very dependent on estimates assigned to the consumer valuations of supply disruption or lost load (VOLL - value of lost load).
6. There are a number of market failures which exist in the electricity market which mean that investment in electricity generation is likely to be sub-optimal from society's point of view. These include the following:
   - *Reliability is a public good:* Consumers cannot, at present, buy reliability of electricity supply for themselves without providing it for everyone else, hence there is little incentive for generation companies to provide it.

- *Prices in the energy-only market do not send the correct market signals to ensure optimal security of supply[2]:* An energy-only market should allow prices to reflect the costs of providing energy, and at times when the system is short and there is energy unserved, prices should rise to the average value of lost load (VoLL). This ensures that investment in generation is remunerated and signals the requirement for new entry. However in practice prices may not rise to sufficiently high levels creating a problem of "missing money". These are due to: (a) the System Operator taking certain actions in the balancing market which can dull price signals; (b) the current methods of calculating prices of system imbalance not representing the marginal cost of generating electricity; (c) Government or regulators in some situations may not allow prices to rise as high as VoLL.
- *There are barriers to entry in the electricity market which could lead to under-investment and insufficient capacity:* A key feature of the current GB arrangements is a lack of liquidity in wholesale electricity markets[3]. This lack of liquidity means that potential new entrants in the generation side cannot be sure of the electricity prices that are being achieved in the energy market. This makes new investment more uncertain and costly and therefore acts as an barrier to new entry.

7. These market and regulatory failures will exacerbate the risks to security of supply when there is a significant amount of low-carbon intermittent generation on the system. This is because it will be necessary to have flexible generation to meet demand when, for example, the wind is not blowing. This flexible generation will cover its costs by running only a small fraction of the time and therefore will be reliant on being able to capture these very high prices at such times. If there is investor uncertainty towards achieving those prices then investment in such flexible generation may not be forthcoming.
8. Whilst Ofgem has proposed reforms to the energy-only market to help increase security of supply, these may not be sufficient to guarantee the desired level of security of supply. Evidence from the modelling undertaken for the Electricity Market Reform programme suggests that even in a perfect energy-only market, we could still expect increased risks to electricity demand not being met (resulting in unserved energy). Given this, and the risk that outcomes will in fact be worse than the modelled result because investors will not have confidence that prices will rise sufficiently high, there is a rationale for intervening to provide increased security of electricity supply.

1.2 Low-carbon options

9. The options for driving investment in low-carbon generation that have been considered are:

- A Premium Feed-in Tariff (PFiT), where all low-carbon generation receives a static premium payment on top of the wholesale electricity price.
- A Feed-in Tariff with Contracts for Difference (FiT CfD) for all low-carbon generation, guaranteeing all low-carbon generation a strike price for the electricity they produce, settled against an indicator of the wholesale electricity price.

10. The Emissions Performance Standard forms part of the package to address the low-carbon objectives and is assessed in a separate Impact Assessment.

[2] Some of the reasons for this might be classified as regulatory failures rather than market failures.
[3] This has been identified by OFGEM as a feature of the GB market. Most recently in: The Retail Market Review – Findings and initial proposals, 21 March 2011

11. The EMR White Paper gives further detail on the decision to implement the FiT CfD and the rationale for this. The preference for a FiT CfD over a PFiT was based on the FiT CfD's ability to promote static and dynamic efficiency through allocating risk efficiently between investors, consumers and the Government. This is achieved by allocating risk to those parties best able to manage or control it. For example, the FiT CfD insulates investors in low-carbon generation from fossil fuel price risk, which they are unable to control, but maintains exposure to a fluctuating wholesale price for those technologies that are able to respond to this signal in their operational decisions.

12. The Premium FiT and the FiT CfD assign risks differently between generators and consumers, as a consequence of the proportion of revenue that that is uncertain. In this respect, the PFiT has a very similar effect to the Renewables Obligation (and they are considered the same for modelling purposes), but the FiT CfD gives greater revenue certainty. This implies that:

- Cost of capital is lower under a FiT CfD than under a Premium FiT. This can be quantified: financing costs are expected to be lower by £2.5bn over the period to 2030 as a whole under a FiT CfD than a Premium FiT.
- Power Purchase Agreements, under which generators currently forfeit some of the value of the electricity in order to be insulated against risk, including price risk, should become cheaper for generators in the future, making the FiT CfD a more efficient support instrument. This cannot be quantified due to a lack of available data.
- Consumers are effectively committed to the decarbonisation targets by implicitly entering into a contract with generators.

13. In addition, the FiT CfD is more effective in bringing forward investment in low-carbon generation. Again, this impact cannot be quantified but qualitative conclusions can be drawn.

14. Promoting efficiency and minimising costs to society has been the main principle in the detailed design of the FiT CfD. For example, by using a year-ahead index for baseload technologies, generators have an incentive to carry out their maintenance when demand is low. Equally, using an unaveraged day-index for intermittent technologies means that risks are allocated efficiently: for example wind generators have an incentive to forecast their output for the following day but do not face uncertainty about the longer-term impacts of large amounts of wind on the system.

1.3 Security of Supply options

15. As part of the EMR White Paper we are consulting on options for a Capacity Mechanism. There are two broad options on the table which are:

- A **targeted mechanism**, with a proposed model of a **Strategic Reserve**, a development of the lead option from the consultation document which aims to mitigate concerns raised by stakeholders. This comprises centrally procured capacity which is removed from the energy market and only utilised in certain circumstances;
- A **market-wide mechanism** in the form of a **Capacity Market,** in which all providers willing to offer capacity (whether in the form of generation or non-generation technologies and approaches such as storage or DSR) can sell that capacity, and the total volume of capacity required is purchased. There are several forms of Capacity Market, depending on the nature of the 'capacity' and how it is bought and sold. In particular, there are a number of ways to purchase capacity – including through a central auction or a supplier obligation. One form of a Capacity Market is a **Reliability Market**. We recognise that there are other forms of market-wide mechanisms, such as those which set price in

order to incentivise sufficient volume (Capacity Payments), and these remain under equal consideration.

1.3.1 Analytical messages

(a) Costs and Benefits

16. The modelled differences in cost between the net welfare impacts of a Strategic Reserve or a Reliability Market are relatively low in absolute terms compared to other EMR proposals. This is not surprising as both a targeted or a market-wide Capacity Mechanism are at least theoretically capable of producing exactly the same outcome if designed efficiently. Any differences are likely to be due to the way that either mechanism is designed.

Table 1: Change in welfare relative to a scenario with no Capacity Mechanism, NPV 2010-2030, £m (2009 real)

Option	Strategic Reserve	Reliability Market
Change in Welfare (NPV) – FiT CfD scenario	**-643**	**-837**
Change in Welfare (NPV) – Premium FiT scenario	**-652**	**-141**

17. Modelling indicates a net cost associated with either Capacity Mechanism. This is because, for modelling purposes, we have applied a security standard of 10% which is somewhat higher than the value of capacity implied by a VoLL of £10,000/MWh. By imposing a constraint that margins are increased to 10%, this will by definition lead to a negative NPV in the modelling. Note that the argument for a Capacity Mechanism rests on the fact that the theoretically perfect market (which is assumed in the modelling), does not exist in practice and just as importantly, investors do not have confidence that prices will be allowed to rise sufficiently high to stimulate that investment. These market and regulatory failures are discussed in paragraph 6 and in more detail in section 4.1 . The NPV is sensitive to the assumptions made around the Value of Lost Load (VoLL). If a higher estimate of VoLL is used in the appraisal, then both mechanisms compared can have a positive Net Present Value (NPV).

(b) Non monetised costs and benefits

18. In addition to the modelling, there has been a detailed qualitative assessment of the two options. These are presented in detail in Section 4 . A high level summary of the qualitative analysis is presented below.

19. A **Strategic Reserve** has a well understood design, has been implemented in several markets, and could straightforwardly be implemented here. From a practical perspective, the mechanism scores highly. However, this model may be less effective in providing the desired level of security because it is likely to be difficult to design without distorting incentives in the electricity market. It may be less effective in incentivising the wider use of non-generation approaches such as demand side participation compared to a market-wide solution and it may be less compatible with increasing inter-system trade[4]. It would also be difficult for this mechanism to be designed to help mitigate the effects of short-term market power without also having an impact on security of supply.

[4] Inter-system trade is used here to refer to interconnection. See Section 4 for further details.

20. The **Reliability Market** form of a Capacity Market is likely to achieve the required security of supply, is potentially more compatible with a longer-term move to a more responsive demand side, mitigates exploitation of market power in the energy market, and is efficient. It also has potential to more strongly incentivise non-generation responses to system adequacy issues such as DSR. However, this is likely to be a larger intervention in our current market, and could also present design challenges. It would need further development and stakeholder input before it could be ensured to work. It also introduces interactions with the FiT CfD, which are likely to make designing the Reliability Market more difficult.

1.4 Cost-benefit Analysis of the Policy Package

1.4.1 Net welfare effects

21. In undertaking the cost-benefit analysis of the options, for which the outcomes of the policy packages are compared to a baseline, it was possible to monetise some costs and benefits but not all. The detailed operational efficiency considerations that have driven the proposed design of the FiT CfD, for example, are not captured in the modelling.
22. The packages modelled includes a low-carbon instrument (the FiT CfD or the PFiT) and a capacity instrument (a Reliability Market or Strategic Reserve), combined with an Emissions Performance Standard.
23. The modelling process set the packages to reach the same illustrative level of decarbonisation of the power sector by 2030 (emission sector intensity of 100gCO_2/kWh) to see how each instrument would reach it and at what cost. Note that the 100g target is more stringent than the baseline and the differences in net welfare are a result both of efficiencies and of the different decarbonisation outcomes.
24. Net welfare is higher with a FiT CfD than a Premium FiT, and it is highest when combined with a strategic reserve.
25. This is driven primarily by the difference between the Premium FiT and the FiT CfD. The different levels of revenue certainty imply different deployment paths over the period, which lead to different combinations of construction and generation costs as well as different savings in carbon costs due to earlier decarbonisation under a FiT CfD.

Table 2: Change in welfare relative to baseline, NPV 2010-2030, £m (2009 real)

£m *Relative to updated baseline(incl. CPF)*	**FiT CfD – Strategic Reserve**	**FiT CfD – Reliability Mechanism**	**Premium FiT - Strategic Reserve**	**Premium FiT - Reliability Mechanism**
Carbon costs	8,860	9,160	6,240	6,180
Generation costs	16,230	15,870	11,460	11,890
Capital costs	-16,070	-16,290	-10,650	-10,360
Unserved energy	120	150	120	130
Demand side response	-40	20	-30	20
Change in	**9,100**	**8,910**	**7,150**	**7,850**

Welfare				

26. These results have been tested under different fossil fuel price assumptions. These show that under high fossil fuel prices, the changes in NPV versus the baseline are £11,270m for the CfD and £5,780 for the PFiT , whereas in a low fossil fuel price scenario the changes are -£660m and £1,230 respectively. Both mechanisms have a higher NPV when fossil fuel are higher and a lower NPV when they are lower. The difference between the mechanisms in each scenario

1.4.2 Bills

27. The FiT CfD package will result in a period of higher investment in low-carbon plant in the 2020s and as a result could lead to slightly increased bills in the short term, compared to the increase in bills in the absence of the electricity reform package where one continues with current policies like the Renewables Obligation and the Carbon Price Floor.
28. In the baseline average domestic bills rise by approximately £200 by 2030. This increase is driven by increases in wholesale prices, network costs, as well as environmental policies such as the Renewables Obligation.
29. Under FiT CfD, the increase in average domestic bills could be limited to £160. For the period up to 2030 as a whole, average bills could be around one to two per cent (or £6 to £10) lower than the baseline. Average domestic bills with the PFiT packages are up to one per cent higher than in the baseline.

1.4.3 Rents

30. Under a FiT CfD, the low-carbon generator receives a top-up payment in periods where wholesale prices are lower than the strike price. As wholesale prices increase the size of these payments reduces and may even become negative, a payment from the generator back to the consumer.
31. Generators receive a stable rate of return irrespective of fossil fuel prices, so that they are insulated from being over- or under-rewarded. The CfD insulates consumers from the possibility of excessive rents and generators from the possibility of low revenues.
32. Under a Premium FiT, however, producers receive all future increases in wholesale prices without any change to the top-up payment, but also face the risk of lower profits under low future fossil fuel prices. Given that all DECC fossil fuel price scenarios show prices increasing in the future, the results nonetheless show that rents are higher under a Premium FiT than a FiT CfD under all scenarios.

1.4.4 Institutional and process design

33. Successful implementation, which depends on decisions made on the institutions to administer the instrument and the process to determine the support levels, will generate benefits that have not been reflected in this IA.
34. The White Paper sets out the key criteria and considerations to determine the appropriate institutional framework. It also sets out an indicative model for delivery on which the full details will be confirmed later in the year. This Impact Assessment contains some illustrative cost estimates for these potential institutional arrangements.
35. Further detail on the process for level setting is given in Annex H: Level Setting.

36. The process design proposals must work alongside related market reforms, in particular the Ofgem liquidity and cashout reviews and future developments on market coupling. The Government supports these reforms.

Section 2 Introduction

2.1 Objective of the Impact Assessment

37. The policy objectives for Electricity Market Reform (EMR) are threefold. Recognising the challenges posed by an increase of intermittent renewables and the retirement of a quarter of the existing fleet in the next decade, the first aim of this programme is to ensure security of supply for the GB electricity system towards the end of the decade and beyond. The second aim is to introduce changes to the current electricity market arrangements so that the Government's decarbonisation objectives as well as the 2020 renewables target can be met. The third aim is to minimise cost impacts for consumers.

38. This Impact Assessment (IA) presents an evaluation of the proposals contained in the Electricity Market Reform White Paper together with an overview of the transitional arrangements and devolution issues. The main sections presented in the IA evaluate the following aspects:

- Options for supporting low-carbon generation – Feed-in Tariffs based on a contracts for difference (FiT CfD) and premium payments (PFiT). FiT CfD are the preferred policy instrument and details of the instrument design and its implementation are also presented.

- Options to ensure security of supply – As part of the EMR White Paper we are consulting on two options for a Capacity Mechanism. The first of these is a strategic reserve, with the second being a more market-based approach to a Capacity Mechanism. Because of the variety of design choices available for a market-wide Capacity Mechanism, it has been assumed that the market-wide approach is a Reliability Market.

- Package analysis – The implications of the EMR package as a whole which takes into consideration the interactions between options where applicable.

39. These options have been assessed against a counterfactual, as described in section 2.2 .

40. The Emissions Performance Standard (EPS - which sets an annual limit on the amount of CO_2 a plant can emit, equivalent to a set emissions intensity factor for a plant operating at baseload) is also part of the EMR set of policy reforms. However it has been evaluated in a separate IA, as the options for the design and level at which the EPS should be introduced (as presented in the EMR White Paper) have been designed such that it will not be binding on the low-carbon incentives or security of supply options.

41. It is important to note that the EMR measures are at different stages in the policy development process. Following the EMR consultation[5] the preferred low-carbon support option (FiT CfD) has been further developed with the key instrument design and implementation challenges addressed. Both this IA and the White Paper present further details on these aspects for the FiT CfD instrument. The security of supply components of the reform proposals are subject to further consultation. This is because, whilst the EMR consultation indicated that Government was minded to introduce a targeted Capacity Mechanism, a significant proportion of stakeholders expressed strong concerns about the introduction of such a mechanism and its impact on the wider market. Therefore to address these concerns, the Government has further

[5] http://www.decc.gov.uk/en/content/cms/consultations/emr/emr.aspx

developed the options for a potential Capacity Mechanism and will consult on these through the EMR White Paper.

2.1.1 Changes since the Consultation Document Impact Assessment

42. Since the EMR consultation IA there have been further policy developments, namely the announcement of a Carbon Price Floor (CPF) policy[6] and changes to the cost assumptions around the delivery of renewables. As a result there are differences in the baseline between the EMR consultation IA and this EMR White Paper IA. Annex E provides further details on the updated modelling assumptions.

43. While the EPS is incorporated in the modelling of packages, due to it being designed to not be binding on the other policies it has been assessed as part of a separate IA.

2.2 Counterfactual for the analysis

44. The counterfactual for the EMR policy proposals as presented in this Impact Assessment is not just the electricity market arrangements as they are currently set, the counterfactual also includes policies which the Government has committed itself to delivering, such as the Carbon Price Floor policy announced in Budget 2011.

2.2.1 Current market arrangements

45. The current market arrangements are considered to be, for the purpose of this Impact Assessment, the current GB electricity market and the policies that affect it. More detail on how the GB wholesale market operates and the proposed reforms to the functioning and the operation of the wholesale market are set out in the EMR White Paper. For the purpose of this assessment the current market arrangements are the counterfactual and it reflects the philosophy underlying the British Electricity Trading and Transmission Arrangements (BETTA) that electricity should be treated as other commodities in terms of market arrangements. The focus of BETTA is around an energy-only electricity market with bilateral trading between market participants.

46. Under BETTA, generators sell their electricity to suppliers bilaterally, rather than through a centralised pool. Parties have financial incentives to balance their contractual and physical positions. The final responsibility for maintaining a physical balance between generation and demand lies with National Grid, which achieves this through a Balancing Mechanism.

47. Wholesale trading under BETTA can be characterised by the following elements:

- forwards and futures markets, that allow contracts for electricity to be struck up to several years ahead;
- short-term ‘spot’ power exchanges, enabling participants to ‘fine-tune’ their contracts up until Gate Closure ;
- a Balancing Mechanism, which opens at Gate Closure, in which National Grid as System Operator (SO) accepts offers and bids for electricity to enable it to balance the transmission system; and
- a settlement process for charging participants whose contracted positions do not match their metered volumes of electricity, for the settlement of accepted Balancing Mechanism offers and bids, and for recovering the SO’s costs of balancing the system.

[6] ‘Carbon Price Floor consultation: the Government response’, HM Treasury and HMRC, March 2011.

48. As an energy-only market, energy itself is the principal traded product. However, a range of different products exist within the market:

- **Energy** – A range of multiple overlapping markets for physical delivery (with scope for financial initiatives) of electricity that operate from several years out right up to 1 hour before real time, after which a centrally run Balancing Mechanism operates;
- **Capacity** – There is no separate Capacity Mechanism for recovery of generator fixed costs with signals for capacity only provided by expectations about peak wholesale energy prices (and imbalance arrangements);
- **Flexibility** – Short-term operating reserve (STOR) provides a revenue stream for generators that are contracted by National Grid to provide flexibility from four hours ahead of real time, all non-STOR generators must recover fixed costs from the wholesale energy market;
- **Renewable** - The Renewables Obligation (RO) is primary source of support for (eligible) renewables (although fixed FITs are available for small generators) effectively acting like a premium payment on top of wholesale electricity prices under the headroom arrangements;
- **Low-Carbon** – Support for low-carbon generation includes funding for carbon capture and storage (CCS) demonstration plants, the impact of the Carbon Price Floor (CPF), CCS requirement of 300MW (net) on new coal plant and CCS-readiness requirements for new combustion plant;
- **European Union Emissions Trading System (EU ETS**) - The power generation sector and energy intensive industries7 have had 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;
- **Carbon Price Floor (CPF)** – CPF was introduced in the Budget in March 2011 (and to be implemented from 1 April 2013) to provide an effective floor to carbon prices (so supplementing the EU ETS with carbon taxation on all fossil fuels used in electricity generation8). The profile of the carbon price feeds in to the long-term expectations of wholesale electricity prices and carbon costs (where applicable). The profile for carbon prices start at £16/tCO2 and take a linear path to £30/tCO2 (2013 – 2020) and then a linear patch to £70/tCO2 (2020 – 2030)

49. The baseline also includes environmental regulations which have an impact on the electricity market and would persist under the 'do nothing option'. These regulations are as follows:

- **Large Combustion Plant Directive (LCPD)** – The LCPD is applied to the power sector (and other industries) to limit SOx, NOx and particulate emissions (from coal and oil-fired generation); and
- **Industrial Emissions Directive (IED)** – The IED introduces tighter emissions limits, particularly for NOx, from 2016 (which will affect gas plant as well as coal and oil plant).

50. Therefore, in the counterfactual, we assume that the current energy-only market remains in place which operates within regulatory environmental limits and alongside the Carbon Price Floor mechanism (following its recent implementation). The RO is the main explicit support

[7] From 2010 aviation will also be included

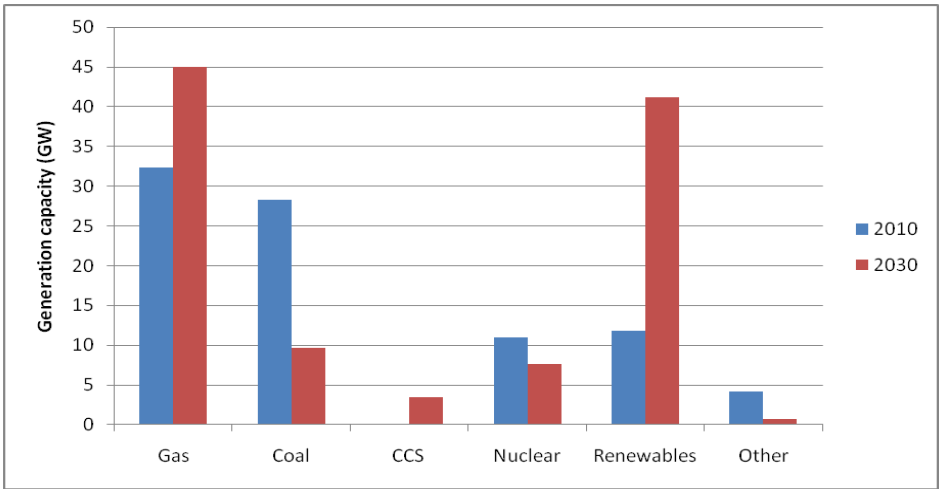
[8] With the expectation that the taxation will be fully passed through to generators and then into wholesale electricity prices.

mechanism for renewable generation, and with the exception of CCS, there's no particular additional low-carbon support mechanisms.

51. We note that there are additional initiatives which have the potential to revise the baselines. These include Ofgem's cash out and liquidity reviews and European market coupling initiative, details of which are summarised in Annex G. Our quantitative assessment of the policy options does not reflect potential reforms in respect of these related initiatives. However, we do consider these developments and their interactions with the EMR policy options on a qualitative basis.

52. Under the baseline described above, the evolution in generation capacity mix from 2010 to 2030, based on modelling projections is shown in Figure 1.

Figure 1: Baseline capacity mix (GW)

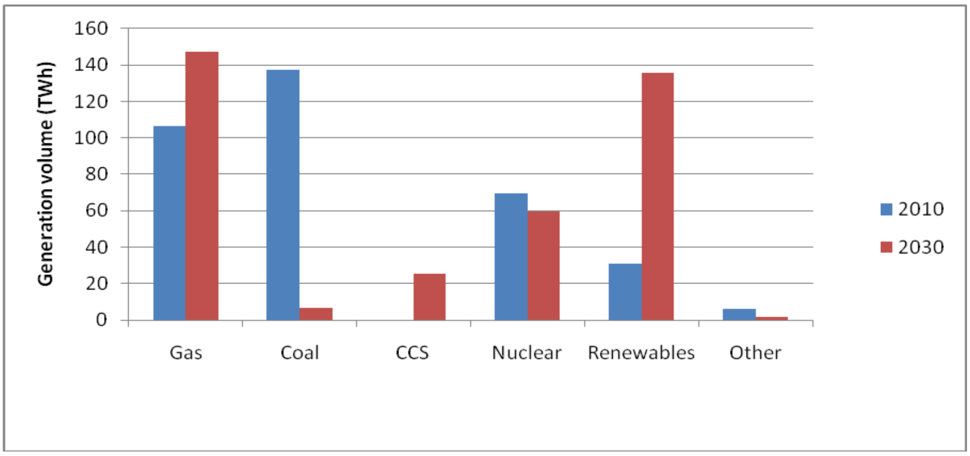


Source: EMR Redpoint analysis

53. It is notable that in the baseline gas-fired generation capacity is projected to increase to around 45GW by 2030. Low-carbon generation is also projected to increase, with total low-carbon capacity at around 50GW. By 2030, fossil fuel fired plant is projected to account for around 55% of total capacity.

54. Figure 2 shows the baseline generation volume mix in 2010 and 2030. By 2030, low-carbon generation is expected to account for approximately 60% of overall output.

Figure 2: Baseline generation mix (TWh)



Source: EMR Redpoint analysis

2.2.2 Government targets and implication for the electricity sector

2.2.2.i Greenhouse gas targets

55. The UK has a target to reduce its carbon dioxide emissions by at least 34% from 1990 levels by 2020, in line with the EU target. Over the longer term, to 2050, it has an ambitious climate change target which will require at least an 80% reduction in emissions across the whole economy. The Committee on Climate Change (CCC) have suggested this can be achieved most cost-effectively if the electricity system makes early progress in decarbonising, allowing transport and heat to be electrified and decarbonised in parallel.

2.2.2.ii Renewables targets

56. A supporting objective is to ensure that an EU target for 15% renewable energy consumption across the UK economy is achieved by 2020. This is likely to mean that around 30% of electricity generated will have to come from renewables by 2020.

2.2.2.iii Decarbonisation ambitions

57. The Committee on Climate Change (CCC), in their latest recommendations for the UK's fourth carbon budget (published December 7, 2010)[9] have suggested meeting longer-term decarbonisation goals is achieved, most cost-effectively, by an emissions intensity of around 50gCO_2/kWh for the electricity sector by 2030.The EMR modelling suggests in the absence of any intervention (the "do nothing" case) the emissions intensity would be around 170gCO_2/kWh by 2030; this is largely because investors' foresight of the rising carbon price is limited (see Annex E).
58. For the purposes of this project, and for consistency with the modelling undertaken for the EMR consultation (which took place before CCC revised its recommendation from 100gCO_2/kWh to 50gCO_2/kWh) we have also used an indicative goal of 100gCO_2/kWh in 2030 to compare the impacts of the different options.
59. Though modelling has used a scenario of 100gCO_2/kWh in 2030, the proposed market reforms could be used to meet different levels of decarbonisation. To address the CCC's latest recommendation of an emissions intensity 50gCO_2/kWh in 2030, a sensitivity analysis with more rapid decarbonisation has also been undertaken to test the robustness of the EMR policy measures (see section 3.6.4)

2.3 Rationale for intervention

60. The rationale for intervention for low-carbon generation and security of supply is discussed in section 3.2.2 and 4.1 respectively.

2.4 Policy Options

61. As well as continuing with the counterfactual (or the "do nothing option") as described in Section 2.1.1 above, the additional options which are assessed in this Impact Assessment are presented below.

[9] http://www.theccc.org.uk/reports/fourth-carbon-budget

2.4.1 Options for incentivising low-carbon generation

62. The options for driving investment in low-carbon generation that have been considered are:

- Premium Feed-in-Tariff (PFiT), such that all low-carbon generation receives a static premium payment on top of the wholesale electricity price.
- A Feed-in-Tariff with Contracts for Difference (FiT CfD) for all low-carbon generation, guaranteeing all low-carbon generation a strike price for the electricity they produce. The FiT CfD would be settled against an indicator of the wholesale electricity price. This is a two-way FiT CfD allowing the agency managing the scheme on behalf of Government to claw back the difference, if the average electricity price is higher than the strike price.

2.4.2 Options for ensuring security of supply

63. The options for mitigating against risks to electricity security of supply include:

- A Strategic Reserve - This is an amount of generating capacity which is held outside of the normal market.
- Reliability Market – A market-based mechanism rewarding all reliable capacity through reliability contracts. Such reliability contracts are essentially financial instruments which preserve the economic incentives to be available at times of system scarcity.

2.4.3 Preferred policy option

64. The Government's preferred policy option for low-carbon support is a FiT CfD and further details of its design and implementation are discussed in later sections of this IA and are also presented in the EMR White Paper. With regards to the options for security of supply these will be subject to further consultation through the EMR White Paper.

2.4.4 EMR Packages

65. The Impact Assessment for the EMR Consultation document assessed the impacts of these options both in terms of how they drive investment individually as well the costs and benefits of using some of them in packages. This Impact Assessment takes a similar approach, however the overall assessment considers the options in packages. Taking this approach enables this assessment to present the interactions of the options as well as present an overview of the intervention on the electricity market as a whole[10]. The packages under consideration are:

- Package 1: Contracts for Difference (FiT CfD), Strategic Reserve (SR), EPS
- Package 2: Contracts for Difference, a Reliability Market (RM), EPS
- Package 3: Premium Feed-in Tariff (PFiT), Strategic Reserve, EPS
- Package 4: Premium Feed-in Tariff, a Reliability Market, EPS

2.5 Approach to assessing the Options

66. The costs and benefits of the policy options have been assessed through:

- Qualitative analysis by DECC, HMT and Infrastructure UK;
- Quantitative analysis undertaken using a dynamic model of the GB electricity market, developed by Redpoint Energy, which simulates investment and generation behaviour. This

[10] It should also be noted, although EPS is part of the EMR policy package, as mentioned previously it is designed to not be binding on the other policy options and so has been evaluated separately.

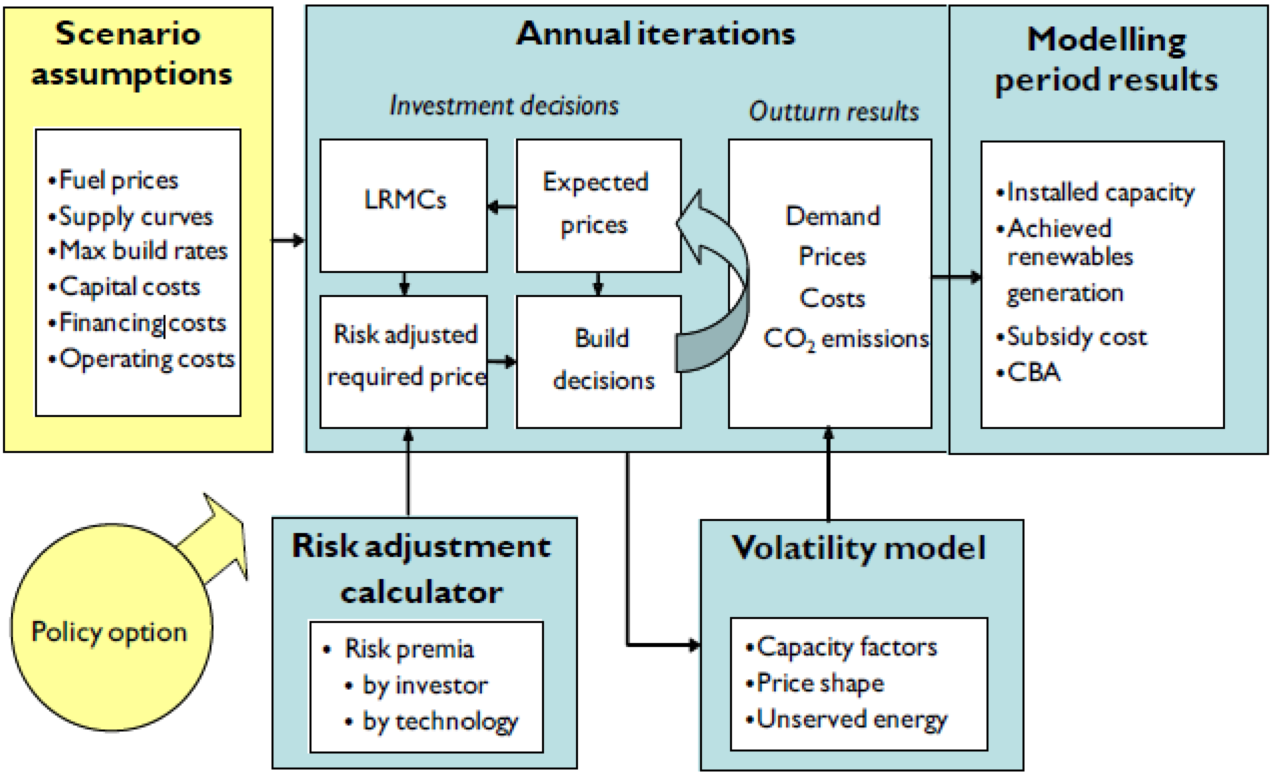
model is a simplification of how investment decisions are made in reality and the results presented in this Impact Assessment should be regarded as illustrative of the potential impacts of the options – See Box 1 below for a description of the Redpoint Energy Dynamic Model. Further detail on modelling assumptions can be found in Annex D.

- Qualitative analysis by Cambridge Economic Policy Associates (CEPA) on cost of capital effects, published alongside this Impact Assessment.
- DECC engagement with electricity sector experts to advise on FiT CfD design and implementation issues and Poyry Management Consulting to advise on electricity wholesale market implications. In addition industry experts from Ofgem, Deloitte and Centrica also advised DECC on various aspects of the project.
- Consultation responses were evaluated, particularly those with direct relevance to the analysis. The majority of the respondents were interested in the modelling of financial decisions. There was significant variance in views but a number of respondents suggested that the analysis should reflect further the complexity of real-world financial decision making, qualitatively if not quantitatively.
- Further stakeholder consultation[11] was undertaken for this Impact Assessment to sufficiently consider the views of new investors such as banks, private equity and infrastructure funds, pension funds, and other investors, who will all be needed for raising finance, given that traditional vertically integrated utilities and independent power producers are capital constrained.

67. The IA considers first the options for policies to incentivise investment in low-carbon generation, against a baseline of current policies (Section 3). Section 4 presents the options for security of supply in a world in which electricity is decarbonised, hence against a baseline which contains a low-carbon instrument. The policy packages as a whole are analysed in Section 5 .

[11] For example with the Low Carbon Finance group, an informal group of senior renewable and conventional energy financiers from across the financial sector.

Box 1: Redpoint Energy Dynamic Model



Section 3 Low-Carbon Support

68. This section considers the options for the support of low-carbon generation. Due to the nature of the proposed instrument and the importance of the detailed design decisions, the section is divided into two parts.

69. Part A compares the costs and benefits of FiT CfD and Premium FiT versus the do nothing option, and shows why the FiT CfD is the preferred instrument, and that this conclusion is robust to changes in input assumptions.

70. The FiT CfD being the preferred option presumes that it can be designed to work. Section B outlines the design questions specific to a FiT CfD, as well as what choices have been made on key design parameters and why.

71. In particular, Part A considers:

- The Do Nothing option
- The rationale for intervention
- A generic description of the policy instruments under consideration
- Impacts of the options

72. Part B elaborates on detailed design of the FiT CfD instrument:

- Specific design principles
- The key design components and the options being assessed
- Evaluation of the design options

Part A: Assessment of the policy options

3.2 Current market arrangements and do nothing option

3.2.1 Do Nothing option

73. The UK is on target to reduce its carbon dioxide emissions in line with the EU target. The main mechanism for driving decarbonisation in the electricity sector is the EU emissions trading scheme (EU ETS). The RO, together with the carbon price, is driving investment in renewables so that the electricity sector can play its part in achieving the renewables target in 2020.

74. As discussed above, the Committee on Climate Change[12] recommends that the electricity system needs to be largely decarbonised by the 2030s, particularly if it is to play its part in decarbonising the heat and transport sectors, in order to be on the right path to the 2050 target. In their latest recommendations, this equates to an emissions intensity of around 50gCO_2/kWh. While the modelling was based on a carbon intensity target of 100g, a 50g sensitivity is discussed in section 3.6.4 .

75. This transition to a low-carbon system presents significant challenges for the current market arrangements, under which, without any other form of Government intervention, there is consensus that the UK will not be on the required decarbonisation path to 2050. Modelling for the EMR by Redpoint Energy suggests that the emissions intensity in 2030 under a 'do nothing'

[12] CCC, *Meeting carbon budgets - the need for a step change*, October 2009

scenario will be around 170gCO_2/kWh. There are also concerns that the high proportion of intermittent renewables on the system will lead to issues with security of supply; this is discussed in detail in Section 4 .

76. The 'do nothing option' retains the current market arrangements described in section 2.2.1 . That is, the existing wholesale electricity trading arrangements are maintained in their current form, the Carbon Price Floor is implemented in accordance with the March 2011 Budget announcement and the RO remains the prime support mechanism for renewable generators (with no explicit support mechanisms for other forms of low-carbon generation beyond those for CCS). Under this baseline, fossil fuel plant is projected to account for over 50% of capacity and around 40% of generation in 2030, with low-carbon plant providing around 40% of capacity and 50% of output.

3.2.2 Rationale for intervention

77. Whilst the UK is on target to reduce its greenhouse gas emissions in 2020 by 34% on 1990 levels, in line with carbon budgets and the EU target, the longer-term goals are more challenging. The electricity system needs to be substantially decarbonised during the 2030s, particularly if it is to play its part in decarbonising the heat and transport sectors in the 2030s and beyond.

78. However, there are reasons to believe that the current market arrangements will not deliver decarbonisation at lowest cost.

79. Cost structures differ between low-carbon and conventional generation capacity investments. Low-carbon investments are typically characterised by high capital costs and low operational costs, while fossil-fuelled investments tend to have relatively low capital costs and high operational costs. The current electricity market was developed in an environment where large-scale fossil fuel plant made up the bulk of the existing and prospective generation capacity, which presents a particular challenge for investment in low-carbon generation.

80. Under the current arrangements, the electricity price is set by the costs of the marginal generator, which is typically a flexible fossil fuel-fired plant. There are currently no scalable low-carbon alternatives to flexible plant. Fossil fuel generation therefore sets the price for all generation in the market, including low-marginal cost low-carbon generation such as nuclear and wind. This means that the electricity price, and hence wholesale electricity market revenue, is typically better correlated with the costs of a fossil fuel-fired plant than it is to the costs of low-carbon plant.

81. Non price-setting plant is therefore exposed to changes in the input costs, including both fuel and carbon, of price-setting plant. If these costs increase, revenues for non-price setting plant increase; if they decline, revenues for non-price setting plant also decline. Therefore whilst non price-setting plant can benefit from increases in the input costs of price-setting plant - costs which the price-setting plant can pass through - they are exposed to lower fuel or carbon prices in a way that price-setting plant are not. As a consequence, investment in conventional capacity is less risky than investment in low-carbon capacity.

82. Under the current market arrangements, mechanisms such as the Renewables Obligation have been introduced to improve the risk-reward balance associated with renewable investment by providing an explicit revenue stream that is not dependent upon the wholesale electricity price. However, given the longer-term decarbonisation objectives, more is needed to provide an

environment that is sufficiently attractive for low-carbon investment and to do so at lowest cost for consumers. The carbon price is unlikely to be strong enough to drive the necessary decarbonisation alone as even with the inclusion of the Carbon Price Floor, our do-nothing scenario (i.e. continuing with current policies) only leads to a carbon emission intensity of the power sector of 170g/kWh in 2030. This is largely driven by the fact that investors lack perfect foresight of the rising carbon price.

83. It is possible that for some technologies, the market will find ways of managing some elements of the revenue uncertainty, such as through contracting between generators and suppliers or through vertical integration. However this may result in unnecessarily high costs for consumers given the costs suppliers incur in managing this uncertainty.

84. As a result, the Government believes that the current arrangements will not be sufficient to support the required new investments in renewables, nuclear and CCS, and ensure these are delivered cost-effectively, as well as providing appropriate signals for investment in new and existing fossil fuel plant. The general consensus is, therefore, that revisions need to be made in order to deliver a sustainable low-carbon generation mix.

3.2.3 Cost-effectiveness of RO in meeting longer-term decarbonisation

85. Whilst the RO could be used to meet the longer-term decarbonisation goals it would not be the most cost-effective way to do this. If the RO were adjusted to include all low-carbon technologies to achieve the longer-term goals, it would in essence become a Premium Feed-in-Tariff (PFiT) and the analysis presented in this IA suggests this would not be the most cost-effective mechanism relative to a Feed-in-Tariff based on Contracts for Difference (FiT CfD).

3.3 Overview of the proposed instruments

3.3.1 Option 1: Contract for Difference

86. A FiT CfD is an instrument which guarantees the generator a price (the strike price) for each unit of electricity sold.

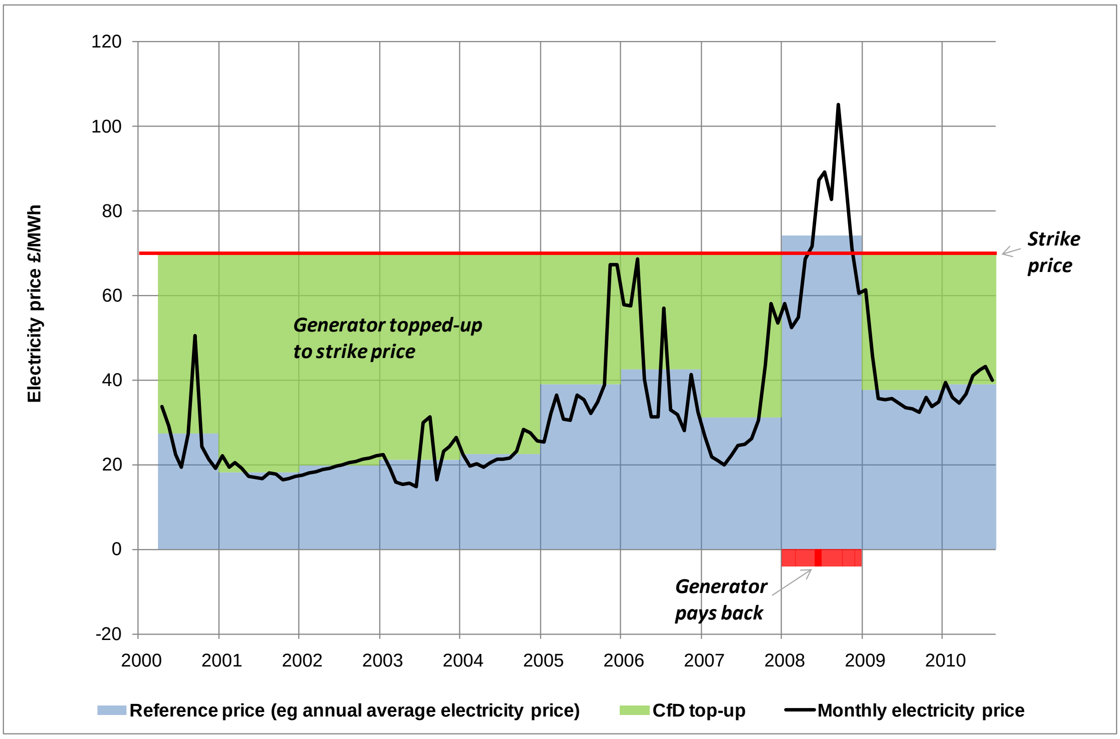
87. Generators' revenue consists of two revenue streams. The first is the variable revenues from the electricity the generator sells in the wholesale market, which is what conventional generators receive under the current system. The second revenue stream is a top-up payment calculated as the difference between the market wholesale price (the reference price) and an agreed strike price.

88. Design specifications such as the strike price or the averaging period of the reference price can be technology specific; hence the instrument can look very different for different kinds of generation, as discussed further in Part B of this section.

89. If in any period the reference price is lower than the strike price the generator receives a payment to make up the difference. Under a two-way FiT CfD, if the reference price is above the strike price the generator pays back the difference. An example payment schedule, with an average annual reference price, is illustrated in Figure 3 below.

90. Further detail on the detailed design of the instrument is given in Part B of this section.

Figure 3: Example Contract for Difference Payment Schedule

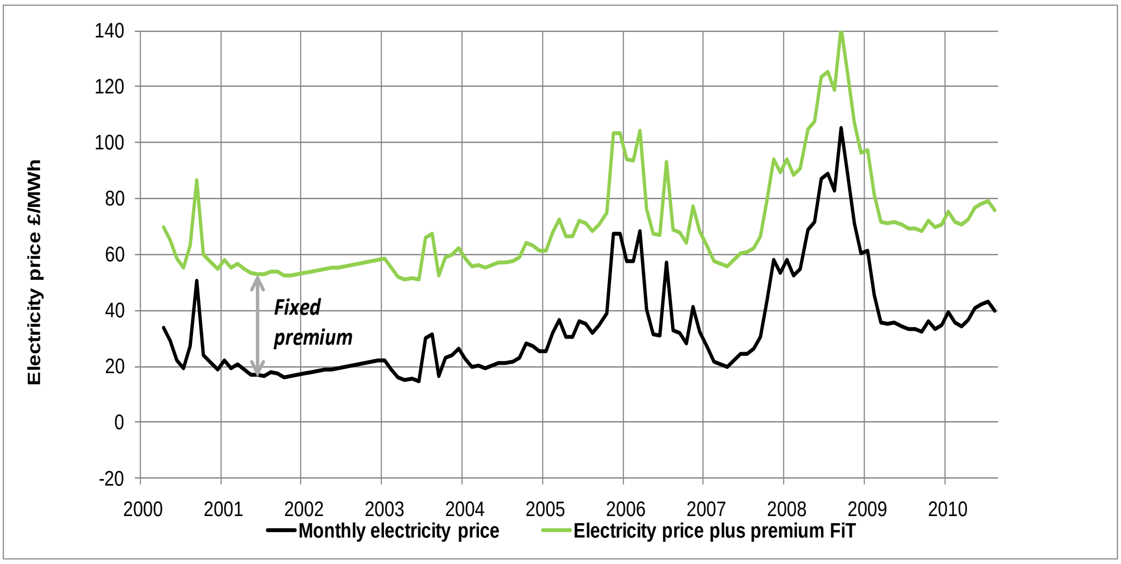


3.3.2 Option 2: Premium Feed-in Tariff

91. A premium feed-in tariff is a static payment for the generator on top of the wholesale price they receive for selling electricity. The payments are designed to account for the additional costs of low-carbon generation relative to cheaper fossil fuel generation. An example payment schedule is illustrated in Figure 4.

92. Similar to the FiT CfD, the Premium FiT gives no offtake guarantee.

Figure 4: Example Premium Feed-in Tariff Payment Schedule



3.4 Preferred option and rationale

93. The preference for a FiT CfD over a PFiT is based on the ability of the FiT CfD to promote static and dynamic efficiency through allocating risk efficiently between investors, consumers and Government. This is achieved by allocating risk to those parties best able to manage or control it. For example, the FiT CfD insulates investors from fossil fuel price risk, which they are unable to control, but maintains exposure to a fluctuating wholesale price for those technologies that are able to respond to this signal in their operational decisions.

94. The Premium FiT and the FiT CfD both change the risk allocation between generators and consumers by reducing the proportion on revenue that is uncertain. In this respect, the PFIT has a very similar effect to the Renewables Obligation, but the FiT CfD gives greater revenue certainty. This implies:

- Cost of capital is lower under a FiT CfD than under a PFiT. This can be quantified: financing costs are lower by £2.5bn over the period under a FiT CfD than a Premium FiT.
- Power Purchase Agreements, under which generators currently forfeit some of the value of the electricity in order to be insulated against risk, including price risk, should become cheaper in the future, making the FiT CfD a more efficient support instrument. This cannot be quantified due to a lack of available data.
- Consumers are effectively committed to the decarbonisation targets by implicitly entering into a contract with generators.

95. In addition, the FiT CfD is more effective in bringing forward investment in low-carbon generation. Again, this impact cannot be quantified but qualitative conclusions can be drawn. This is further discussed in the report by CEPA published alongside this IA.

3.5 Efficiency implications of the options

3.5.1 Efficiency of risk allocation

96. Both the FiT CfD and the Premium FiT transfer revenue risk away from low-carbon generators to give them more certainty in their returns. This should in principle lead to lower financing costs and a higher likelihood that any particular project will proceed.

97. Both policy options reduce the risk faced by generators, but in different ways; Table 3 gives an overview of types of risk for generators under EMR proposals. It is important to distinguish between the risk of volatile prices and the risk that stems from uncertainty about long-term wholesale price trends.

98. While the FiT CfD removes price risk by giving a long-term strike price, the Premium FiT dampens the risk from wholesale price movements by reducing the proportion of revenue that is subject to this risk (compared to no support – the current RO system works in much the same way as the Premium FiTs proposed).

Table 3 Impact of EMR options on revenue risk for investors in low-carbon, compared to baseline

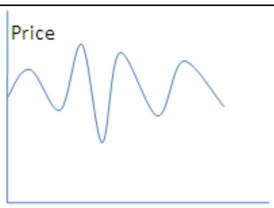
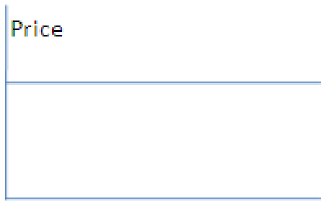
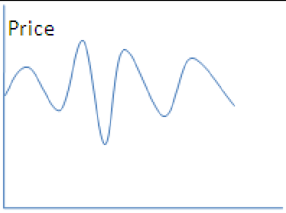
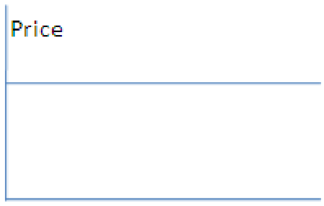
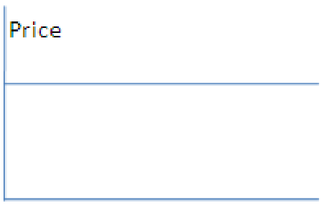
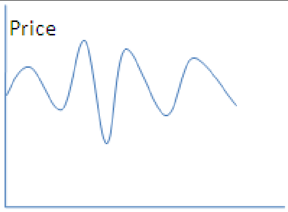
Element of revenue risk	FiT CfD	Premium FiT
Electricity price risk	Largely removed	Dampened
Volume risk	No change	No change
Balancing risk	No change	No change

Cannibalisation risk[13]	Reduced	No change

99. This means that FiT CfDs and Premium FiTs allocate risks between generators and consumers in different ways. As illustrated in Table 4 below, a Premium FiT leaves some exposure to the wholesale price with generators, leading to revenue, and consumer bills, being subject to both volatility and long-term price uncertainty; if fossil fuel prices are higher/ lower in the future than anticipated, this will affect both.

100. A FiT CfD, in contrast, insulates generators and consumers from both short-term volatility and the impacts of long-term price trends; higher- or lower-than expected gas prices have no effect on price received by the generator or bills paid by consumers. This means that consumers will be shielded from longer-term wholesale price increases, but also that they will not gain from longer-term wholesale price decreases. Changes in wholesale prices only affect the amount of support paid out by Government; hence the price risk is borne by Government balance sheets.

Table 4: Risk allocation under FiT CfDs and Premium FiTs

	Premium	FiT CfD
Revenue for generators		
Bills for consumers		
Government support payments		

101. A FiT CfD therefore effectively commits consumers to decarbonisation by establishing an implicit contract with generators whereby consumers, in order to meet these targets, forsake the opportunity of low bills in the future if gas prices were low; generators, in turn, forsake the opportunity of high profits in a high gas price scenario in return for being shielded from low gas prices.

102. This is welfare neutral as long as consumers do not have a preference for being exposed to the possibility of higher or lower future prices. There is no concrete evidence to suggest that consumers would welcome such risk insulation, but neither is there evidence that consumers would prefer risk exposure.

[13] The electricity price will be driven down by high volumes of wind.

103. Currently, generators are exposed to wholesale price risk and manage this through a range of strategies, for example diversification or buying financial products. This risk management is costly, and adds to the overall cost of supplying electricity. This issue is further discussed below.

3.5.2 Efficiency gains from improved terms of Power Purchase Agreements

104. A Power Purchase Agreement (PPA) is a contract between a generator (who supplies the electricity) and an offtaker (who buys the electricity). The terms of the PPA can differ, reflecting how much risk remains with the generator and how much is borne by the offtaker; the generator pays the offtaker to take on risk.

105. The argument set out in this section suggests that given that the FiT CfD decreases revenue risk for the generator, the terms of the PPA should improve in the generator's favour, leaving him with more value and hence lower requirements for support, resulting in a saving for consumers.

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

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

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

108. There is a case that, if designed appropriately, relative to the ROCs, the FiT CfD could reduce the need for the scale of discounts under PPAs associated with providing a price floor and to deal with cannibalisation; so with a FiT CfD in place, the generator would not need a PPA to manage revenue risk, whereas under the PFIT he would. This would make the PPA under the PFIT more expensive to the generator.

109. More detail on evidence on the size of discounts and its components can be found in the CEPA report published alongside this document.

3.5.3 Incentives for market entry and exit

110. The core objective at the heart of generation investment decisions is to earn a profit. There is nothing to suggest that the package of EMR proposals will change this ultimate objective. But the EMR proposals will alter the environment within which generation investment decisions are made.

111. The proposals are specifically designed to support investment in a sustainable generation mix by providing a more predictable revenue stream for potential investors in the capacity required to deliver policy goals. The proposals are not, in general, intended to have a significant impact upon wholesale electricity prices. Rather, to provide increased revenue certainty, the proposals protect particular types of generation from exposure to energy price variability and create price certainty for non-energy products, such as capacity and low-carbon or renewable generation.

112. Finally, given the extent of change being proposed, we recognise that the market and investment community will need to understand how the revised arrangements will operate and their implications for them. This is essential for the future operation of the arrangements and its importance for future investment cannot be underestimated. Steps to aid market and investor understanding of the package will be invaluable in helping to compress the time required to become comfortable enough to commit funding to projects under the revised arrangements.

113. The FiT CfD can reduce revenue uncertainty for prospective low-carbon generators. While revenue from the wholesale market remains an important revenue stream, FiT CfD generators are, assuming they can secure the relevant reference price for their output, effectively insulated from variations in the wholesale price. Overall revenue expectations are, instead, based upon the agreed FiT CfD strike price. In the short term, this provides an effective hedge to the impact of variations in fossil fuel prices on wholesale prices and, in the longer term, to the effect of the carbon price dropping out of the wholesale price as the system de-carbonises. If investors are confident that they are able to secure contracts with an appropriate strike price, then low-carbon investment should be forthcoming.

114. The Premium FiT and RO vintaging instruments provide eligible generators with certainty regarding the expected price for low carbon/renewable products. However, they are not insulated (as under the FiT CfD) from variability in wholesale market price. This means that these generators are able, if running, to capture upside linked to periods of high wholesale prices, whilst also facing downside exposure if producing in periods of low prices. This is equivalent to the present situation under the RO. Investments are expected to be undertaken in cases where risk-adjusted expectations of wholesale capture prices plus administered low carbon/renewable product values provide an adequate revenue stream in combination.

3.5.4 Incentives for market participants to compete

115. The EMR proposals will have a bearing upon competition throughout investment, trading and operational timescales.

116. Decisions in respect of setting support prices (be it the FiT CfD strike price or the Premium FiT) for different technologies or projects will affect competition to invest and obtain low-carbon support contracts. For instance, administered prices have the potential to be set at inappropriate levels, tilting the balance between different projects/technologies, while some technologies may be excluded under competitive technology neutral allocation processes. In addition, any disparities between support levels for equivalent renewable technologies under the vintaged RO and a FIT may affect their relative competitiveness. Clearly, only low-carbon projects that are able to secure FIT contracts will be able to participate in the market. Market entry for low-carbon generation will, therefore, be effectively contingent upon holding a FIT. This could present a risk for potential investors, which may pose a barrier to entry.

117. The proposals may also affect competition in trading. The FiT CfD is expected to concentrate trading activity into the relevant reference market. This may, therefore, reduce trading activity in non-reference windows as trades will increasingly be diverted to the reference periods. Given the reference market for baseload FiT CfD plant, this should, in principle, increase competition in the seasonal/annual products. However, whilst the potential to 'beat the market' and secure the best possible price is genuine, a low wholesale price is not an issue as long as others have a similarly low price. As they will get topped up via difference payment, it is arguable that the key objective for these plant will be to match the market to avoid losing out relative to equivalent

plant. The herding instinct may, therefore, prove to be the more powerful driver. If this is the case, the competition benefits of a concentration of trading activity may not be realised.

118. The same is likely to apply in the day-ahead market, with the incentive to match the market arguably more important than beating the market price. However, the day-ahead market has the potential to be volatile given that variation in intermittent generation may make the market unbalanced. If there is significant intermittent volume (relative to demand), it will be a buyer's market. Conversely, if there is limited intermittent volume (relative to demand), it will be a seller's market of which intermittent generators (FiT CfD and RO alike) have only a small share. The implication is that intermittent generation is unlikely to be on the 'right' side of the market and will capture prices lower than the average day-ahead price (if a PPA is in place, this is likely to be reflected in the contract pricing also). FiT CfD contracted capacity will receive a top-up price to effectively compensate for this, intermittent generation under the RO is not in this position.

119. In operational timescales, competition in the balancing mechanism may also be affected by the proposals. If FIT generators received support payments based on availability, rather than metered output, in the event that they are constrained down by the system operator, they would not need to reflect lost support payments in their bid prices for the constrained period (although if the constraint affects availability over a longer period, bid prices may seek to recover lost payments over the extended period). The implication is that bid prices for these plants should more closely reflect the physical costs of reducing generation and are less likely to be negative. This suggests that parties will compete on the basis of generation related costs rather than support payments. Remuneration for capacity under the RO will remain production based, however, so bid prices for these plants are expected to continue to reflect lost support payments.

120. Under the FiT CfD options, support payment levels will be known ahead of gate closure (year-ahead for baseload and day-ahead for intermittent). If FiT CfD generators with low/zero short-run marginal costs have uncontracted capacity at gate closure (this will exclude generation whose contracted volume is based on its actual metered output via, for example, a PPA) and the support payment is positive, they could submit offers into the balancing mechanism at low or negative prices as a means to secure additional revenue. In contrast to the bid stack, this could alter the merit order of the offer stack.

3.5.5 Incentives to trade: liquidity

121. The EMR proposals do not alter the requirement for generators to sell their output into the market either via contractual offtake arrangements, forward trading, the balancing mechanism or imbalance. But patterns of trading activity are likely to change. The instruments involving FiT CfDs have the greatest effect on trading behaviour.

122. For new renewable and low-carbon generation, the support schemes remove one of the perceived advantages of the PPAs because the co-products of electricity (e.g. renewable and low-carbon) are no longer only attractive to a particular type of counterparty (i.e. electricity suppliers under the RO). In theory, this could make other contracting strategies, such as wholesale market trading more attractive increasing the range of possible counterparties (beyond suppliers) and hence intensifying competition. However, the appetite to do this in practice will depend on the attitude to risk of the generator, and the importance of imbalance

exposure, and the ability of the generators to manage this (whereas under a PPA, the imbalance risk is normally left with the off-taker).

123. If FiT CfD generators sell their output through an offtake agreement such as a PPA rather than trading activity, it is likely that the price within the PPA will be based upon the FiT CfD reference price. This would protect them from price and volume risk, however the offtaker may charge a premium for this depending on how well placed they are to handle the associated price (e.g. access to reference market) and volume risk.

124. The expectation is that FiT CfD plant will seek to trade in the market from which the reference price is determined in order to mitigate potential basis risk. For baseload plant, this is expected to concentrate trading activity into seasonal/annual products over the 12 month period leading up to the relevant delivery period, whilst potentially reducing activity in other products. The effect will be to divert trading activity and liquidity into the relevant reference market and away from alternative markets.

125. For intermittent FiT CfD plant, the driver to trade in the reference market also exists. In this case, trade will be focused into the day-ahead market. Again, this should, in principle, divert trading activity into this window, increasing liquidity and opportunities for all players to fine-tune positions close to real-time. However, the day-ahead market has the potential to be volatile given that variation in intermittent generation may make the market unbalanced i.e. a buyer's market in periods of high intermittent generation (relative to demand) and a seller's market in periods of low intermittent generation (relative to demand). This could have implications for competition as discussed further in Section 3.5.4 .

126. Owners of conventional capacity do not have the same constraints as the FiT CfD capacity and are arguably in the best position to arbitrage between the different markets and benefit from trading activity. They can trade ahead to secure contracted sales volume backed by reliable, controllable generation capacity. Conventional capacity has, to a greater extent than baseload FiT CfD plant, the ability to choose whether to trade in the year-ahead markets depending upon price expectations or to trade in alternative markets/re-trade. As real-time approaches, anticipated volumes of intermittent generation can be projected more accurately and conventional generators have the option to arbitrage positions traded further ahead and, for example, buy surplus intermittent generation relatively cheaply and back-off its own capacity.

3.5.6 Innovation

127. The incentives for technological innovation stem from the potential rewards of cost reductions. Technology-specific long-term contracts may dampen these; the extent to which premium payments do depends on the size of the payment relative to the electricity price.

128. The impacts of FiT CfDs and premium payments can be reduced through the way that payments are set and whether they are open to all technologies. An auction system could be open to all technologies and therefore technology neutral. Innovation should reduce project costs and lower strike price requirements, improving prospects of securing contracts via an auction. This is clearly depends on the design of the auction system: the impacts on innovation and therefore the efficiency of the electricity system over time need to be carefully considered in the implementation of these options. An important consideration in terms of innovation, if the incentives are set by Government, is the built-in expectations of the declining low-carbon

payments. It is also important that the mechanism does not lock out future technologies or developments to existing technologies.

129. It should be noted that the signals for innovation for balancing technologies, including demand side response and storage will still be dependent on the wholesale price signal and revenue potential associated with a potential Capacity Mechanism.

3.5.7 Availability of finance

130. The FiT CfD may also have an impact on the availability of capital. Given the need for low-carbon generation financing of around £70 - 75bn by 2020, this is a substantive benefit.

131. The FiT CfD, by giving greater revenue certainty, may be more effective than the Premium FiT in attracting new sources of capital, in particular institutional investors, to the sector, the main benefit of which is that it will allow the debt capital provided by project finance lenders to be recycled into new investments.

132. This is discussed further in the report by CEPA published alongside this Impact Assessment.

3.6 Cost-benefit analysis

3.6.1 Net welfare

133. The impact on net welfare of the two options for FITs has been assessed by combining the two options for FITs with the two options for Capacity Mechanisms to form four packages of EMR policies:

- Package 1: Feed-in Tariffs with Contracts for Difference + Strategic Reserve
- Package 2: Feed-in Tariffs with Contracts for Difference + Reliability Market
- Package 3: Premium Feed-in-Tariff + Strategic Reserve
- Package 4: Premium Feed-in-Tariff + Reliability Market

134. Table 5 summarises the results of the modelling in terms of the change in net welfare under each one of the options between 2010 and 2030[14].

Table 5: Change in net welfare relative to baseline, NPV 2010-2030, £m (2009 real)

£m *Relative to updated baseline(incl. CPF)*	**FiT CfD - SR** CPF	**FiT CfD - RM** CPF	**Premium FiT - SR** CPF	**Premium FiT - RM** CPF
Carbon costs	8,860	9,160	6,240	6,180
Generation costs	16,230	15,870	11,460	11,890
Capital costs	-16,070	-16,290	-10,650	-10,360
Unserved energy	120	150	120	130
Demand side response	-40	20	-30	20
Change in Net Welfare	**9,100**	**8,910**	**7,150**	**7,850**

135. The impact on net welfare of the EMR policies is due to the packages' impact on investment and generation decisions in the electricity market. EMR proposals incentivise investment in low-carbon plant. Investment in low-carbon plant typically leads to relatively higher capital costs

[14] It should be noted that Redpoint apply discounting from year 1,which is different from the Green Book approach.

and lower generation costs compared to a scenario with a higher share of fossil fuel-fired generation plant. This is because low-carbon plant have higher up-front capital/construction costs (but lower generation costs) than conventional fossil fuel generation. There are also obviously savings in carbon costs in a low-carbon electricity system.

136. Overall, the analysis shows that even though the packages will lead to relatively higher capital costs, this increased cost will be offset by a reduction in generation costs and carbon costs, which means that the packages have a net benefit.

137. The FiT CfD performs better than the Premium FiT in net welfare terms, regardless of the security of supply option it is considered in a policy package with.

138. More detailed discussion of the results can be found in section 5.1.1.i .

3.6.2 Sensitivity to fossil fuel price assumptions

139. It is necessary to assess whether the conclusions derived under central assumptions hold under different states of the world.

140. One FiT CfD and one Premium FiT package (each combined with a Strategic Reserve mechanism) were tested for key sensitivities to assess the robustness of the packages. It is important to note that the results of the sensitivity analysis on the two packages with a Reliability Market Capacity Mechanism might have yielded different results in absolute terms.

141. In order to bring out the differences between the packages in terms of cost and benefits, the packages were modelled so that they would meet the same renewable electricity penetration and carbon intensity of the grid as assumed in the central case modelling.

3.6.2.i Fossil fuel prices

142. Future fossil fuel prices are inherently uncertain. Therefore, the Baseline, Premium FiT and FIT CFD packages, the latter two with a Strategic Reserve Capacity Mechanism, were modelled under central, high and low fossil fuel and carbon price scenarios.

143. It must be noted that unlike the approach taken for modelling fossil fuel price sensitivities for the EMR consultation document, this analysis is based on a modelling approach in which it was *imposed* on the packages to meet a 100g/kWh carbon intensity of the power sector.

144. Table 6 below shows the trajectory of fossil fuel price assumptions under the low, central and high scenarios used in this modelling.

Table 6: Fossil fuel price assumptions under low, central and high scenarios[15]

	Gas (p/therm)	Coal (£/tonne)	Oil ($/bbl)
	Low		
2015	34.0	32.0	59.3
2020	34.5	32.0	61.4
2025	35.0	32.0	61.4
2030	35.4	32.0	61.4
	Central		
2015	64.8	51.1	76.7
2020	68.5	51.1	81.8

[15] Sourced from DECC's 2010 Updated Energy Projections. Further details on trajectories of prices are provided in Annex A.

2025	72.3	51.1	86.9
2030	76.1	51.1	92.0
High			
2015	85.0	63.9	104.1
2020	98.7	63.9	122.7
2025	98.7	63.9	122.7
2030	98.7	63.9	122.7

(a) High fossil fuel prices

145. In the high fossil fuel price scenario, the carbon intensity of the power sector reaches around 100gCO_2/kWh in 2030 in the baseline scenario, without imposing this on the model (as is done for the EMR packages modelling). There is an overall positive net impact of both the FiT CfD (£11.3bn) and Premium FiT packages (£5.8bn), compared to the baseline.

Table 7: Change in net welfare relative to the updated baseline with high fossil fuel prices, NPV 2010-2030 £m (2009 real)

£m *Relative to high FF baseline*	**FiT CfD - SR, High FF** CPF, EPS	**Premium FiT - SR, High FF** CPF, EPS
Carbon costs	6,440	1,850
Generation costs	10,730	3,470
Capital costs	-6,120	240
Unserved energy	190	190
Demand side response	40	30
Change in Net Welfare	**11,270**	**5,780**

146. In the FiT CfD package in particular, there are savings in carbon costs as decarbonisation is much more rapid than in the baseline. There are savings in generation costs as there is less output from gas plant and more from coal and CCS plant (which has lower fuel costs than gas plant). Capital costs, on the other hand, are higher in the FiT CfD package due to more build of CCS capacity.

147. There is a very positive impact on consumer surplus in the FiT CfD package under high fossil fuel prices. This is due to lower electricity prices (for non-FiT CfD plant) and much lower low-carbon support payments needed in the FiT CfD package, driven by nuclear coming on earlier. In fact, the low-carbon support payments are negative in the years 2027-2030, which is passed through to consumer bills.

148. It should be noted that, as with the central fossil fuel price assumption results presented above, the modelling does not restrict the packages to meet the same electricity generation mix.

(b) Low fossil fuel prices

149. For the reason outlined above, the three scenarios were also modelled using low fossil fuel price assumptions.

150. In the low fossil fuel price scenario, the updated baseline scenario reaches a carbon intensity of around 190g CO_2/kWh in 2030, which is higher than under central fossil fuel price assumptions (170g CO_2/kWh in 2030).

Table 8: Change in net welfare relative to the updated baseline under low fossil fuel prices, NPV 2010-2030 £m (2009 real)

£m *Relative to low FF baseline*	**FiT CfD - SR, Low FF** CPF, EPS	**Premium FiT – SR, Low FF** CPF, EPS
Carbon costs	3,390	2,470
Generation costs	10,930	8,570
Capital costs	-15,150	-10,000
Unserved energy	190	190
Demand side response	-30	0
Change in Net Welfare	**-660**	**1,230**

151. The change in overall net benefit for the FiT CfD package is -£0.7bn compared to the baseline under low fossil fuel prices. This is explained by the fact that whilst the baseline scenario has largely new CCGT build (which has relatively low capital costs) there is more new nuclear with PFiT s or FiT CfDs and, in the case of the FiT CfD package, CCS build. The higher capital costs associated with the FiT CfD package's build profile (£15bn) outweigh the savings realised with lower cost of EU ETS allowances and generation of electricity.

152. In the Premium FiT package, the increase in capital costs relative to the baseline is around £5bn lower than in the FiT CfD scenario. This is because in this scenario, there is around 5GW more new low cost gas plant built than in the FiT CfD scenario, and less new build of high capital cost technologies. Whilst carbon cost and generation cost savings are also lower in the Premium FiT scenario than in the FiT CfD scenario, there is an overall *positive* impact of the Premium FiT package of £1.2bn relative to the baseline.

153. Overall, the fossil fuel price sensitivity analysis shows that in terms of impact on net welfare, the FiT CfD option for reform is considerably better than the Premium FiT options under high fossil fuel prices. In the case of low fossil fuel prices, however, the NPV is higher under the Premium FiT package, but the difference between the packages are much less in a low fossil fuel scenario than in the high fossil fuel scenario. Therefore, if one does not assume that one fossil fuel scenario is more likely than the other, on balance, the FiT CfD option is preferable to a Premium FiT option.

154. In addition, there are distributional implications of the options, discussed below.

3.6.3 High and low hurdle rate reductions

155. In the Redpoint model, the higher revenue certainty for generators achieved by the FiT CfD versus the Premium FiT results in lower return requirements for investors. It is important to note that the reductions are generated by the model and are not an input assumption.

156. These hurdle rate reductions (shown in Table 9 below) lead, through lower financing costs, to savings in technology costs. When the Premium FiT hurdle rates are applied to the generation mix achieved with a FiT CfD, the technology costs are £2.5bn higher over the period to 2030: this is the saving achieved by lower hurdle rates.

Table 9: Summary Redpoint hurdle rate reductions

	Baseline	Premium	FiT CfD
Hurdle rates (typical utility)			
Onshore wind	8.1%	0.0%	-0.3%
Offshore wind (R1/R2)	10.1%	0.0%	-0.5%
Offshore (R3)	11.1%	0.0%	-0.5%
Regular Biomass	11.0%	0.0%	-0.5%
Biomass CHP	12.0%	0.0%	-0.6%
Hurdle rates (nuclear developer)			
Nuclear	12.7%	-0.9%	-1.5%

157. There is uncertainty around the exact size of these hurdle rate reductions. To assess the robustness of the modelling results to this uncertainty, DECC commissioned further analysis, published alongside this Impact Assessment, to test the Redpoint figures, and also tested a range of cost of capital figures in the model.

158. The analysis, which was based on an alternative methodology taking explicitly into account the need for views from investors and how financing decision are made in the real world, led to results broadly consistent with the Redpoint figures. Due to data and time constraints, only wind technologies and nuclear were investigated further. The resulting ranges of hurdle rate reductions are shown in Table 10: the results for wind technologies are broadly in line with the Redpoint results; the nuclear results are the same as in Redpoint.

159. Two sensitivities were then modelled by Redpoint. In a “low reduction” scenario, it was assumed that the introduction of a FiT CfD did not lead to any reduction in hurdle rates for onshore wind projects, and that the reduction in offshore wind was the same as Redpoint’s original assumption (a -0.5% reduction). In the “high reduction” scenario, the reduction in hurdle rates for onshore wind were the same as those originally assumed by Redpoint (-0.3%) but reductions for offshore wind were higher (-0.8%).

Table 10: Hurdle rate reduction assumptions for sensitivity analysis

	Absolute hurdle rate (typical utility) FiT CfD - SR	Low reduction FiT CfD - SR	Central reduction FiT CfD - SR	High reduction FiT CfD - SR
Onshore wind	8.1%	0.0%	-0.3%	-0.3%
Offshore wind R1/R2	10.1%	-0.5%	-0.5%	-0.8%
Offshore wind R3	11.1%	-0.5%	-0.5%	-0.8%
Nuclear	12.7%	-1.5%	-1.5%	-1.5%

160. The two additional scenarios were modelled so that the new build wind plant would be similar to that of the FiT CfD package with central hurdle rate reductions assumptions. This was achieved by altering the FiT CfD strike price to reflect the fact that the Long Run Marginal Cost of wind technologies had now changed[16].

161. The results of these sensitivity runs demonstrate that the impact of these new hurdle rate reduction figures on net welfare is very small under both the low and high hurdle rate reduction scenario, shown in Table 11 below.

162. As expected, the change in annual net welfare in the "low reduction" FiT CfD package scenario is worse than under the central reduction (original) FiT CfD package. Nevertheless, the impact is marginal – net welfare under low hurdle rate reductions is only £391million (NPV, real 2009) worse than under the central FiT CfD package. This reduction in welfare is mainly due to increased capital costs of projects as a result of the higher hurdle rate assumptions used for onshore wind projects

163. In the "high reduction", there was an increase in net welfare, relative to the central FiT CfD package scenario, of £363 million (NPV, real 2009). This is due to the lower capital costs for offshore wind projects.

Table 11: Change in capital costs and net welfare for FiT CfD-SR package in High and Low hurdle rate reduction packages, relative to central FiT CfD-SR package, NPV 2010-2030 £m (2009 real)[17]

£m *Relative to central FiT CfD package*	**FiT CfD – SR, Low Hurdle Rate Reductions**	**FiT CfD – SR, High Hurdle Rate Reductions**
Capital costs	-364	443
Change in Net Welfare	**-391**	**363**

164. Distributional analysis shows that low-carbon payments increase by £484m under the low hurdle rate reduction scenario to compensate for increased LRMCs for onshore wind projects. This is an increase in the transfer from consumers to producers, hence consumers are worse off relative to the central FiT CfD package scenario. Under the high hurdle rate reduction scenario, on the contrary, low-carbon payments have decreased by around £748m.

165. The sensitivity analysis therefore shows that changes in the hurdle rate reductions, while they feed directly into technology costs and hence support levels, have a marginal effect on NPVs.

3.6.4 Carbon intensity of electricity grid of 50gCO_2/kWh in 2030

166. In the central cases the packages are modelled to meet a decarbonisation ambition of 100gCO_2/kWh in 2030. The Committee on Climate Change's latest recommendations however include a 50gCO_2/kWh ambition for 2030. In light of this, the packages have also been modelled to meet a 50g target, to test their robustness in a scenario with more rapid decarbonisation.

167. Table 12 shows the change in net welfare in the packages modelled to reach a carbon intensity of 50gCO_2/kWh in 2030 compared to the updated baseline.

[16] In all the modelling, the FiT CfD strike price is set at a level just above the Long Run Marginal Cost of technologies.

[17] For simplicity, changes in carbon costs, generation costs, unserved energy and demand side response are excluded here as these impacts are only minor.

Table 12: Change in net welfare, relative to the updated baseline, reaching 50g/kWh carbon intensity of electricity sector in 2030, NPV 2010-2030 £m (2009 real)

£m *Relative to updated baseline*	**FiT CfD - SR, 50g/kWh**	**Premium FiT – SR, 50g/kWh**
Carbon costs	15,790	13,720
Generation costs	16,260	11,230
Capital costs	-26,800	-21,820
Unserved energy	140	150
Demand side response	20	10
Change in Net Welfare	**5,400**	**3,300**

168. The modelling indicates that there is a positive net benefit in both packages of meeting 50gCO_2/kWh (relative to the baseline).This is due to very significant EU ETS carbon cost and generation cost savings. These savings outweigh the higher capital costs associated with the low-carbon build profile.

169. Nevertheless, more ambitious decarbonisation is more costly: the improvement in welfare is *less* under the 50gCO_2/kWh carbon intensity sensitivity than in the 100gCO_2/kWh runs.

170. These costs are higher under a PFIT than under a FiT CfD because the support needed to bring on low-carbon generation to the scale required is higher.

171. In the FiT CfD package, this lower carbon intensity target is reached by an additional 9.6GW of new nuclear being built to 2030 (19.2GW in total) compared to the FiT CfD package meeting 100gCO_2/kWh carbon intensity, whilst under premium payments the target is met by a combination of increase in CCS and nuclear new build.

172. It should be noted, however, that there are potential significant risks associated with these deployment rates , including (but not limited to) technology risks, planning issues, grid expansion, connection risks, supply chain risks and construction delays. The modelling does not explicitly factor these in, but we recognise that they may create barriers to the deployment of low-carbon generation. In addition to this, the lower wholesale electricity prices in these scenarios means that there would be a much reduced ability of the market to provide long-term price signals for investment by 2030.

173. Nonetheless, this run shows that our choice of FiT CfD as instrument is robust to potential changes in decarbonisation ambition.

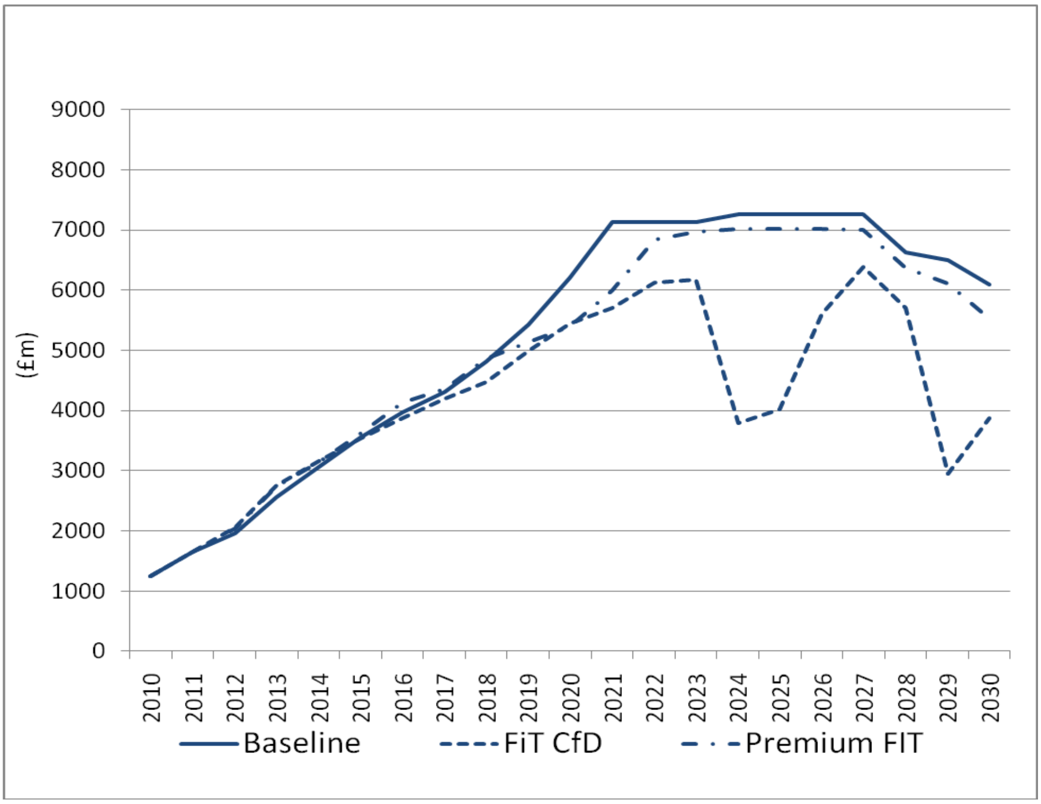
3.7 Cost of public support

174. The low-carbon support mechanism requires payments to generators and these are likely to fall under the definition used by the Office for National Statistics for spending and taxation. This means that the payments will appear in the public finance aggregates. Figure 5 shows the

support costs of the low-carbon options (including legacy costs from the Renewables Obligation (RO)) in the central case compared to the baseline (with RO).

175.

Figure 5: Costs of support for low-carbon mechanisms



Source: EMR Redpoint analysis

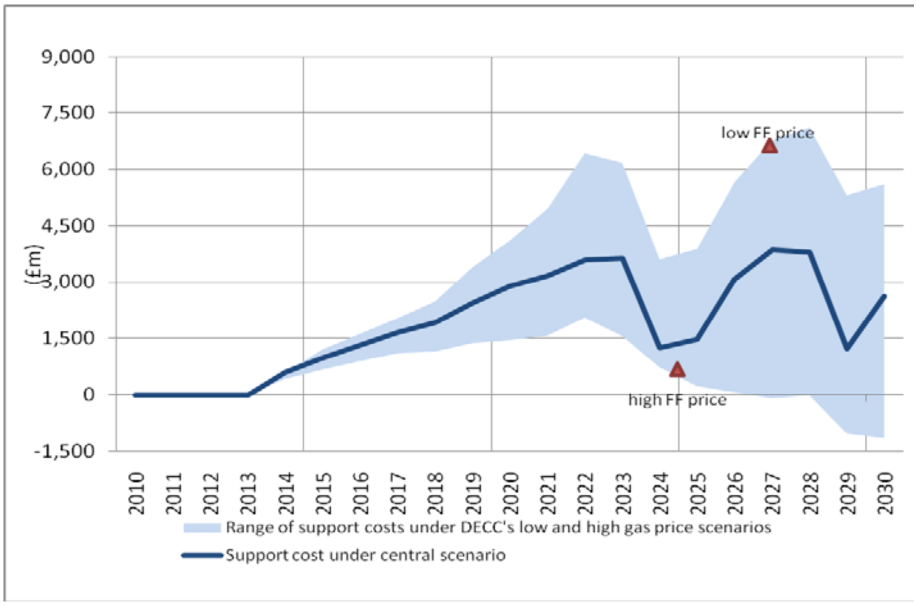
176. The low-carbon support mechanism requires payments to generators and these are likely to fall under the definition used by the Office for National Statistics for spending and taxation. This means that the payments will appear in the public finance aggregates. Figure 5 shows the support costs of the low-carbon options (including legacy costs from the Renewables Obligation (RO)) in the central case compared to the baseline (with RO).

177.

178. Figure 5 shows both the FIT CFD and Premium FiTs (both including legacy RO costs) can result in savings in terms of low-carbon support relative to the baseline. The FiT CfD results in savings of around 19% relative to the baseline, compared to the Premium FiT which saves around 4% relative to the baseline. However the FiT CfD support costs do exhibit greater volatility.

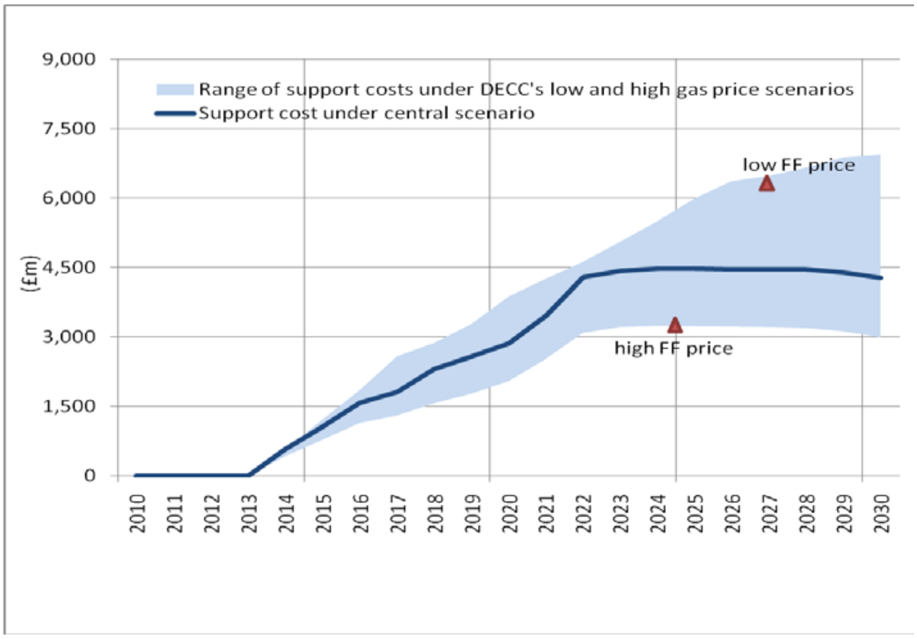
179. Figure 6 and Figure 7 below shows how the FiT CfD and Premium FiT support costs in the central case compare against costs under high and low fossil fuel (FF) price sensitivities.

Figure 6: Cost of support for FiT CfD under high/low fossil fuel price scenarios



Source: EMR Redpoint analysis

Figure 7 Cost of support for Premium FiT under high/low fossil fuel price scenarios



Source: EMR Redpoint analysis

180. The charts above show the cost to public finances of a FiT CfD is more volatile and uncertain than a Premium FiT. However the future cost of a Premium FiT is also uncertain, as future premia will need to be adjusted in the light of changes to the wholesale electricity price. While the FiT CFD may be more volatile it remains the lowest cost support option, being around 30% lower than the Premium FiT in the central case and even under a low fossil fuel price scenario (where low-carbon support costs would be greater) it has an average annual cost which is around 9% lower than the Premium FiT.

3.8 Impacts on business

181. The direct impact on businesses and the implications under One In One Out are assessed in the package section.

3.8.1 Administrative burdens on business

182. As part of the Government's Better Regulation agenda, the UK has adopted the Standard Cost Model (SCM) method of providing an indicative measurement of admin burdens, and DECC is monitoring the impact of its regulations on business and taking initiatives to minimise the administrative burden they impose. An administrative burden is the cost to business of the administrative activities that it is required to conduct.

183. An estimate of the cost to business is given by the following formula:

Activity Cost = Price X Quantity = (wage x time) X (population x frequency)

184. The time taken to complete an activity and the wage rate of the person undertaking the task are based on the figures for a normally efficient business. The population is given by the number of businesses affected; and the frequency is the number of times per year that business has to undertake the activity.

185. The admin costs would arise from any new activities that a participating business would need to undertake beyond that which it already does. Whilst it is difficult to ascertain precise costs the following section details the activities and highlights whether these result in new costs.

3.8.2 Direct costs to generators

186. The direct costs to generators are likely to be associated with the registration and contract negotiation process in addition to any arising from FiT CfD/PFiT settlement and regulatory costs. There will also be some transaction costs in selling power, however these are unlikely to be different to those seen now.

187. Costs of registration and negotiation: There is likely to be some form of registration and negotiation process with the various institutions during build/commissioning process (likely to be component of issuing the FiT CfD/PFIT contract detail). Some of these costs are likely to be similar to those experienced under the current RO regime. On the cautious assumption that there are likely to be some new costs to generators from the registration and negotiation process we have taken a similar approach to that of the Reliability Market approach under the Capacity Mechanism (see section 4.3.1.v (c)).

188. Assuming that the population is the number of parties that might participate, our current best estimate of this is between 80 and 239[1]. It is expected that each company participating in the FIT CFD/PFIT would require between one and two members of full time staff to prepare for the registration and negotiation process.[2] The average cost of each member of staff is estimated to be around £50,000[3]. Therefore the administrative burden placed on business of this mechanism is estimated to be between £400,000 and £2.4m per year.

[1] Lower figure comes from 5.11 in DUKES and is the number of major power producers. The upper figure represents the current number of Balancing and Settlement Code parties.
[2] This would need to be consulted on either by hiring consultants, or by interviewing the relevant companies.
[3] This is the cost of business consultant in BIS guidance.

189. Costs of FiT CfD/PFIT settlement: The management of the power position itself is likely to be a key cost of administration, however generators would do this anyway as part of their normal business activities. Moreover settling the FiT CfD could be a simple monthly process which would entail multiplying volume (daily output from either metered data or the feed from Elexon) by the Fixed Strike Price less the market reference price (MRP).

190. These minor settlement costs will be lower than the alternative operating under the RO: i.e. the removal of the need to claim for and administer ROCs – which is a relatively complex process.

191. Reporting/regulatory burden: These are likely to be similar to the RO if not easier.

3.8.3 Costs to Suppliers (mandatory, e.g. via licence condition, not optional)

192. There may be some administration costs from recovering the cost of FiT CfD from consumers (as well as continuing to collect RO income) however this again is undertaken by suppliers as part of the RO (this would include the majority of suppliers). Hence there would be some cost synergies in this regard, and costs would be expected to be negligible (if any).

Part B: Detailed instrument design

3.9 Introduction

193. This section summarises the proposed design of the FiT CfD instrument. It is structured in four main sections:

- Section 3.10 outlines how the broad evaluation objectives identified in the Consultation Document issued in December 2010 have been expanded into a set of specific design principles to develop the low-carbon (LC) instrument; and
- Section 3.11 provides a summary of the key design components and the options being assessed;
- Section 3.12 summarises the proposed structure for the FiT CfD
- Section 3.13 sets outs the costs and benefits of the various options.

194. As described in the White Paper and detailed in Table 14 in this IA, the Government is minded to adopt certain aspects of FiT CfD design, including having different structures for technologies with different characteristics and defining the nature of the market reference price for intermittent and baseload technologies. There are some FiT CfD design characteristics that are still open, the most significant of which is the choice between paying baseload contracts on metered output or firm volume. Where there is a preferred option, this is stated in each section. These proposals are subject to the final design of any Capacity Mechanism.

195. There are some elements of FiT CfD design, such as the price source for the reference price, where the options are outlined in this IA with a discussion of the potential costs and benefits of each. It may however be more appropriate for the institution awarding the FiT CfD contracts to define these elements closer to the point at which the contracts are signed.

196. It should also be noted that, when compared to the proposed FiT CfD structures for intermittent and baseload technologies, the proposed approach for ‘flexible plant’ is at an earlier stage of development and is only one option for bringing forward investment in this type of plant.

3.10 Design Principles and Criteria

3.10.1 Overview

197. The primary objective of this instrument is to stimulate investment in LC technologies at the lowest cost to the consumer. The proposed design needs to recognise and satisfy a number of other important objectives reflecting wider policy goals and market impacts. However, these objectives are not independent of one another and, in some cases, fulfilling one may compromise the ability to deliver on others. It follows that the proposed instrument design needs to strike a careful balance between amount of risk removed from investors and risk to consumers as well as these wider policy objectives.

198. Table 13 summarises the key principles developed to support and inform the design of the FiT CfD instrument. Annex I expands on these design principles and indicates how these principles influence the proposed contract design.

Table 13:Design Principles

Efficiency	
P1	LC instruments are designed to promote cost-efficient LC investment
P2	Recognise that commercial and operational behaviour varies across different classes of generation
P3	Avoid removing normal commercial incentives for active market participation while ensuring the generator is able to achieve (hedge) the FiT CfD reference price
P4	Avoid dampening, diluting or otherwise distorting price signals for reliability and availability aimed at operating across the entire industry/market (e.g. such as the balancing mechanism (BM))
P5	Mitigate risk of distorting or damaging the liquidity and depth in the GB power market and, where possible, support positive development of liquidity
Cost to Society	
P6	Provide for efficient allocation of risks between generators and consumers
P7	Mitigate risk of potential for windfall profits and extraction of excessive rents
P8	Mitigate risk of gaming and contract manipulation to prevent enhanced profits at the consumers expense

Barriers to Entry	
P9	Avoid arrangements which favour a particular corporate structure
P10	Mitigate perceived or real impact associated with the removal of the Supply Obligation under the existing RO regime
P11	Ensure open and competitive process of awarding contracts
Coherence	
P12	Ensure consistency between FiT CfD contracts and other elements of the EMR reform programme including and the potential introduction of capacity payments
P13	Ensure consistency between EMR reforms and Ofgem liquidity initiatives and cash-out reform
Practicality & Durability	
P14	As far as possible, enable contracts to adapt to changing market environment and rules
P15	Recognise that current lack of liquidity poses a significant interim challenge
P16	Keep contracts simple in a complex market environment
P17	Recognise that internal capabilities of the target investor community will vary across different classes of generation

3.11 Options - design components

199. This section provides an overview of the key design components of a FiT CfD and describes the options assessed in this IA. It is important to recognise that there are many interdependencies between these components which must be taken into account in the overall instrument design. However, for ease of explanation we first provide a brief general introduction to each component before describing in more detail how they are combined to form proposed contracts for each of the above plant classes.

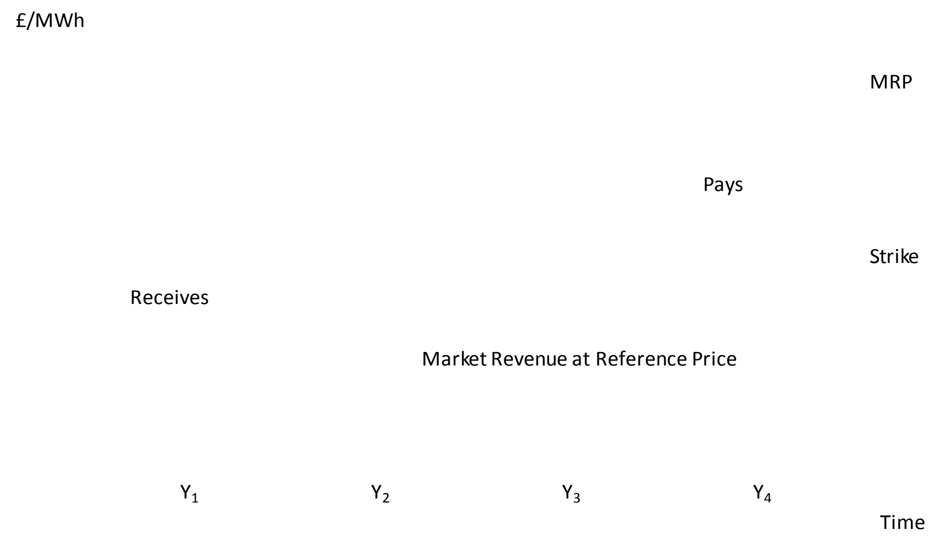
3.11.1 Contract Form

200. Most FiT CfD structures adopt one of two basic forms:

3.11.1.i Two-way FiT CfD

201. Under a two-way FiT CfD, the generator receives the difference between the market reference price and the contract strike price - when the reference price is below the strike price. When the reference price is above the strike price, the generator pays back the difference. A two-way contract therefore fixes the price for the contract quantity (see Figure 8).

Figure 8 – Two-way FiT CfD



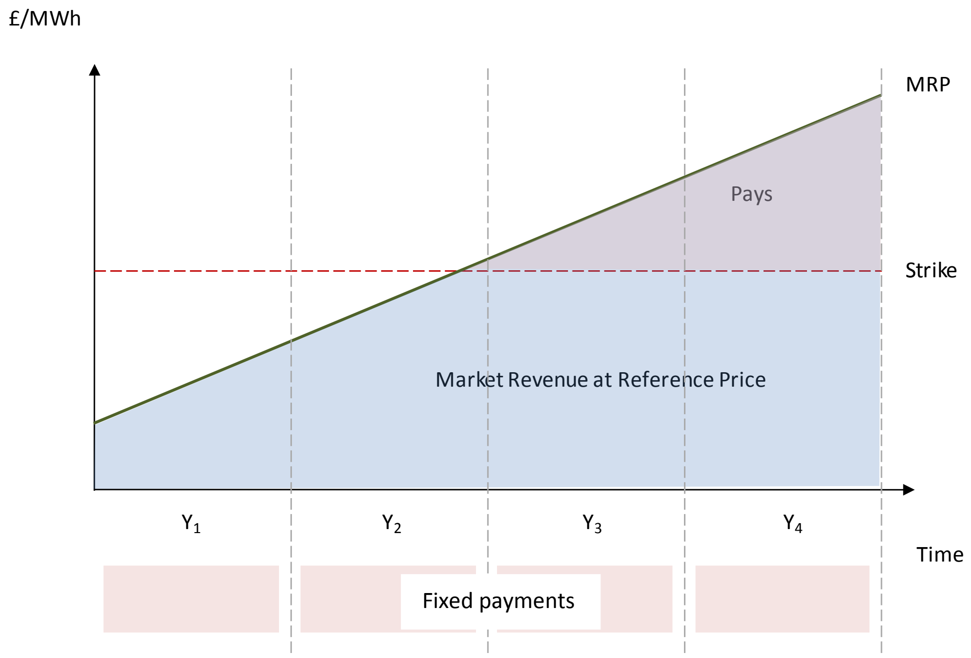
3.11.1.ii One-Way FiT CfD

202. Under a one-way FiT CfD, the contract only requires difference payments in one direction. For example, a generator pays difference payments when the reference price is above the strike price, but will not receive offsetting payments when market prices are below. The generator would receive a payment in return for providing such (one-way) price insurance (effectively to consumers that the price will not go above a certain level). An alternative form of a one-way FiT CfD is where the generator is guaranteed a minimum price and retains the benefits when prices are higher than the strike price (i.e. the generator is paid the difference when market prices are below the strike price but does not pay back when power prices are high).

3.11.2 Strike Price

203. The determination of the strike price for the FiT CfD will be made as part of the allocation process (see Annex H). However, we recognise the need for investors to achieve a return reflecting real-terms and as such a need for indexation in the strike price exists. Secondly, where there are cost drivers reflecting the marginal cost of the plant e.g. fuel costs, then these could be recognised in the FiT CfD by adjusting the strike price accordingly.

Figure 9: Example of a one-way FiT CfD



3.11.3 Market Reference Price

204. In order to determine the payments to be made under a FiT CfD contract a market reference price (MRP) needs to be defined. There are at least four aspects to consider:

- **Market Segment:** The MRP defines the market segment against which the FiT CfD is settled. In this context, the choice of the element of the market used to mark the FiT CfD needs to consider spot, prompt (i.e. day-ahead) or forward traded products. Alternatively it could be a basket of some or all of these;
- **Averaging Period:** The second element is to determine whether these prices should be taken individually or averaged over a longer period (either forward or backward looking) to place additional incentives on the generator other than simply hedging the FiT CfD into the market segment;
- **Price Source:** Third, once the market segment and averaging period are selected, we need to define the source from which the data is provided for settlement purposes. For the contract to function operationally, it is critical that the chosen MRP is created from robust and credible data sources; and
- **Revenue Realisation:** Across all of these aspects, is it the case that the generator is able to earn the MRP in the market? The MRP should be achievable through trading and commercial operation in the market place, so the generator can sell output at the MRP and when combined with the difference payment to meet the strike price crystallise the revenue anticipated. This aspect must therefore consider the technology in context of their operation, scale and predictability.

205. The issue of market liquidity is a key driver in establishing robust MRPs. We recognise these FiT CfDs will direct market liquidity themselves but it is also a pre-requisite that the MRP is liquid in its own right. It is important that the selection of an MRP for different technology

classes directs liquidity to similar market segments as it does now. These FiT CfDs must be able sit within the existing market framework and allow the generators to hedge their output to the MRP, remain exposed to market signals in the short-term and if as a by-product they can improve on market liquidity in GB then this should be seen as an added benefit rather than the aim of the FiT CfDs themselves.

206. It should be noted that we would expect an investor to aim to sell their output at the MRP as companies try to align their trading strategies in order to avoid basis risk and securing revenue in line with the strike price. Indeed, a trading approach that diverged from selling into the MRP would be regarded as speculative (this is not an invalid business strategy).

3.11.4 Contract volume

207. There are at least three different options for setting the contract volume:

- **Metered output:** A FiT CfD which is settled against the metered output from the generation plant will pay difference payments only if the plant is operating. Hence, any low-carbon support embedded within the contract is paid for low-carbon electricity produced. It follows that such a FiT CfD necessarily is specific to the plant in question: settlement is on the basis of output (MWh).
- **Availability/capacity:** A second option is to settle the FiT CfD on the basis of the capacity of the plant, a payment for the plant being available to generate rather than on the basis of its actual production. The support is therefore paid using MW as the contract volume.
- **Firm (or fixed) volume**: A firm volume FiT CfD means that difference payments are calculated for an agreed fixed number of MWhs, rather than actual generation or available/capacity. Hence, difference payments are made on the contract quantity (MWhs) and do not depend on actual generation. A firm volume contract is therefore financial and can be traded by anybody who wishes to hedge or speculate on the MRP. In the energy markets, this is a common basis for settling commercial CfD products.

  An example of firm volume CfDs are those in NordPool, which offers CfDs to cover the spread between the NordPool (day-ahead) system price and the local price in the particular price zones. Hence, it allows the buyer to lock in the basis risk between zonal and system prices.

3.11.5 Other terms

208. There are a number of other terms which will need to be defined to bring the FiT CfD to market. These include:

- **Settlement period:** The frequency in which payments are made/received under the FiT CfD
- **Contract duration:** The length of the contracts;
- **Enforcement of contract obligations**: In order to ensure effective operation of the contract and that conditions associated with contract award are carried out to achieve the goals of EMR; and
- **Terms for credit and collateral**: The credit terms including requirements for security and credit-worthiness of the developer.

209. These terms will often be similar for all generation classes and hence for all FiT CfD instruments. We consider these common terms in section 3.13.7 .

3.12 Overview of Proposed Design

210. The Government is minded to adopt different FiT CfD structures for intermittent and baseload technologies as set out in Table 14 below. The FiT CfD structure for flexible technologies is at an earlier stage of development, however we describe one option in this IA. This FiT CfD for flexible technologies broadly consists of a fixed payment to cover a generator's fixed costs combined with a one-way FiT CfD that is structured in a way that provides generators with an incentive to generate when the electricity price is greater than their marginal costs.

Table 14: Proposed FiT CfD terms (refer to Figure 8 and Figure 9)[18]

	Intermittent	*Baseload*
Contract Form	• Two-way FiT CfD	• Two-way FiT CfD
Strike price	• Annual inflation indexation	• Annual inflation indexation • Minded not to include fuel indexation for biomass. To be confirmed for CCS commercial deployment.
Market Reference Price	• Day-ahead price • (choice of baseload vs. hourly prices) • Not averaged over a longer period	• Year-ahead price • Averaged over 12 months prior to delivery year
Contract Volume	• Metered output	• To be confirmed: metered output or firm volume

211. For CCS demonstration projects, we are assessing the feasibility of support through a form of FiT CfD alongside other approaches. We expect support for these early projects will need to be different to that for commercially proven CCS and other low-carbon baseload options, given the additional risks involved with investment in CCS demonstrations.

212. In particular, these projects are likely to be less reliable and predictable. As a consequence there is greater revenue risk when compared to other low-carbon generation options if support is delivered solely through a FiT CfD based on output. We are therefore assessing the possibility of incorporating some form of fixed payment in the FiT CfD making up part of the support package for CCS demonstration projects.

3.13 Costs and Benefits of CfD design options

3.13.1 Case for more than one CfD structure

213. While a CfD instrument can be applied to all types of generation capacity, the specific design does need to recognise the characteristics of the plant being supported by the instrument. Any contract (or for that matter, any FiT) has the potential to influence a generator's commercial incentives and operational behaviour, which vary considerably across different types of plant. In the following we distinguish between following three classes of plant:

- **Intermittent:** Plant which has little or no control over despatch profiles (beyond a decision to be available or not) and for which fuels costs are not a consideration. This class therefore includes wind as well as other non-despatchable and low fuel cost technologies such as wave and solar.

[18] These proposals are subject to the final design of any Capacity Mechanism

- **Baseload:** Plant which (subject to ambient conditions) operate at a constant level of generation with no or limited ability to vary output and respond to despatch instructions. In addition to nuclear generation, this class may also include some form of biomass plant[19] and CCS.
- **Flexible:** Plant which has the ability to control the output (within certain maximum and minimum parameters) and respond to despatch instructions in different timeframes. This class therefore includes plant which is capable of operating in the mid and peaking segments of the merit order. It will in general be associated with variable and volatile fuel costs. Low-carbon technologies include most forms of biomass as well as, in the future, potentially CCS.

214. It is noted that this classification is not technology specific as illustrated in Table 15. It is intended to reflect and capture the very different operational characteristics of plant within each of these classes (whatever the specific technology).

Table 15: Technology Allocation

	Intermittent	Baseload	Flexible
Technologies	• Wind • Marine • Solar • Tidal	• Nuclear • Gas & coal CCS and biomass operating as baseload	• Gas & coal CCS and biomass

215. The differences between the operational characteristics in each of the above classes are real and failure to acknowledge their practical implications would lead to sub-optimal solutions. For example, intermittent generation such as wind is by its very nature subject to a large degree of volume uncertainty which it cannot control. While wind (and other intermittent generation) can and should have an incentive to improve short term forecasting capabilities, such generation will inevitably “spill” into the short term markets. Exposing intermittent generation to volume and price risk beyond the very short delivery timeframe would detract from investor attractiveness and increase cost of capital without providing any additional benefits to the power system or the consumer.

216. In contrast, flexible generation is comprised of plant which is able to vary production in response to despatch instructions. It is therefore critical that the LC support to plant in this class does not remove or dampen the market price signals against which such plant continually is optimised. Applying identical design parameters to both classes would either leave excessive risk with intermittent generators or too little market exposure with flexible generators. For this reason the proposed contract design is specific to each class of generation, even though the overall instrument remains the same.

217. Flexible contracts would be aimed at investors to build and operate plant once the baseload sector has been decarbonised (via inflexible baseload FiT CfDs).

3.13.2 Contract Form

3.13.2.i Intermittent and baseload

218. The proposed FiT CfD for intermittent and baseload generation is a two-way contract.

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

219. Principle P7 is the overriding reason for this choice since a two-way contract shields the consumers from overcompensating developers. The FiT CfD is a long term contract set at a price level to ensure that the generator receives sufficient remuneration to deliver a commercial rate of return over the life of the investment (assuming they sell their electricity at the MRP). In return for this price support, the two-way contract has an inbuilt mechanism which ensures that the generators return monies to consumers if electricity prices consistently exceed the level of remuneration required to provide a commercial return.

3.13.2.ii Flexible

220. The proposed FiT CfD for flexible generation is a one-way contract.

221. In contrast to the two-way FiT CfDs for the other groups of technologies, a different structure is required to promote mid-merit operation for plant often with a significant fuel price component. As these costs vary (fuel and carbon prices), a two-way FiT CfD striking against the power price does not stabilise margins in the same way as for nuclear and other low-carbon technologies such as wind. A more appropriate instrument is a one-way FiT CfD (see 3.11.1.ii), which would only require payments (from the generator to the "agency") if the power price exceeded the marginal cost of generation. However, in a period of low power prices or high fuel prices the generator would not generate. To ensure adequate returns on the investment the FiT CfD would periodically pay a fixed amount to cover the fixed cost component of the plant.

222. If the fuel spread is positive (and the plant runs) the generator pays the difference between the power price and the fuel reference price; so assuming that the generator sells its power and buys its fuel/carbon close to the respective indices its margin will be close to zero and it will simply receive its low-carbon premium. The generator would receive income from the market by selling power and would have an incentive to optimise within year performance. If the generator performed well and scheduled maintenance efficiently, income from the market would exceed the margin payments, resulting in higher returns.

3.13.3 Strike Price

3.13.3.i Profile of strike price

(a) Intermittent and baseload

223. It is proposed that the strike price (SP) is flat (in real terms) but with provision for indexation to compensate for inflation.

224. The level of the strike price is agreed during the contract allocation process (see Annex H).

225. An alternative option would be to include an element of "sculpting" in line with expected views of forward electricity market. If the strike price is flat and electricity prices are expected to increase, then the top-ups will be high at the beginning of the contract and low (possibly receipts) by the end. This would have implications for consumers, who might rather see their payments rise gradually, rather than pay it all up front. However, it would provide an element of levelling consumers' bills, as support reduces this is offset by power prices rising but this could give rise to a significant step-change in bills if a large volume of FiT CfDs are issued early on.

226. It should also be noted that investors place greater weight on revenues in earlier years (because of discounting). Therefore, the benefits to Government in back-loading the FiT CfD payments may increase the strike price required so that actually it becomes more costly for

Government. Investors may also command a higher strike price if the project is exposed to a higher degree in later years.

(i) Use of Indexation

227. For contracts to remain attractive for investors the need to increase the strike price to reflect time value of cash is an important component. This is a widely used concept and is seen both in the existing RO and in the small-scale FIT contracts. As with all generation classes, we propose indexation should be applied to the strike price to reflect inflation.

(b) Flexible

228. **In contrast to other FiT CfD forms the strike price would be set at the short run marginal cost of the plant**. The strike price will therefore vary on the basis of the price reference used for fuel. As with other reference prices, the generator will need to purchase fuel on a similar basis to the reference price used to fix the strike price to reduce their basis risk. This ensures the generator fixes its SRMC at the strike price. It may include an element of indexation (though this may be dealt with in the fixed payment instead).

3.13.3.ii Linking support price to the cost of fuel

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

230. In contrast to other forms of low-carbon generation, a biomass (and CCS) operator has a fuel price element to consider in their generation process. Unlike wind (which has no fuel costs) and nuclear (which has a low fuel input cost coupled with stability in that price) a biomass and CCS generator needs to purchase fuel for the production of electricity. Over the lifetime of a project this price is likely to vary significantly. This provides an additional risk in that the cost of generation is not covered in the reference price[20] and which, if left with the developer, could put pressure on the cost of capital of such projects therefore leading to a higher strike price.

231. There are several options for linking support levels to fuel costs. One is to consider the spread between the power price and the price of the fuel and use this differential to create the reference price. This may add an unnecessary layer of complexity to the contract as the MRP becomes a function of more than one market. This could be difficult for the generator to manage.

232. Another potentially simpler option is to use a fuel cost index on an annual basis to adjust the strike price. A change in the cost of fuel would then directly impact the support provided as the strike price would change reflecting the movement in the fuel price.

233. Fuel price indices exist for coal and gas but are less mature for biomass. There are some relatively new indices currently available in the market e.g. APX-Endex Index for Wood Pellets delivered to Europe. The exchange provides a forward view of prices (for 3 years) as well as an assessment of spot prices. This is regarded as one of the better indices available, but it is recognised that more time is needed to develop trading around the index for it to become a trusted and robust reference price for the biomass industry.

[20] Biomass is a very small element of the existing GB Power market so the price of its fuel does not contribute to the power price – this is in contrast to coal and gas prices which have a direct impact of power prices as market participants actively manage their power portfolios with respect to movements in the price of coal and/or gas.

234. The benefit of linking support levels to fuel costs is that the FiT CfD strike price would be lower, reflecting the lower level of risk taken on by generators. In principle, however, there is no reason why Government would be better placed to manage fuel price risk than industry; Government has no more information about the likely evolution of fuel (biomass, coal or gas) prices than industry.

235. Incorporating a link between support levels and fuel costs would also provide a barrier to comparing the costs of technologies at some point in the future [P11] .

236. The proposed approach does not link support to the costs of fuel for biomass. The approach for commercially deployed CCS is still open given the period of time before likely commercial deployment. The current CCS demonstration project links support costs to the cost of fuel.

3.13.4 Market Reference Price

237. This section focuses on the MRP characteristics for intermittent and baseload plant. In the case of flexible plant many of the MRP characteristics would be similar to those for baseload plant: the predictability of output enables a generator to plan ahead in terms of maintenance cycles and seek out the periods of high price in which to operate. However, the FiT CfD should be structured to promote generation during periods when the power price is above the SRMC. This implies generating during peak (or extreme-peak) periods only. This FiT CfD structure is likely to be more complex that the relatively simple FiT CfDs outlined below and the detail has not yet been determined. The MRP will most likely be based upon a short-term index with the potential for using peak prices as a reference or sculpting of a baseload price to promote output at higher price periods.

3.13.4.i Market Segment

238. The selection of the MRP determines the market segment and time "bucket" used for settlement. A generator will need to earn the MRP to realise the full support provided by the LC FiT CfD. The MRP therefore needs to represent a market segment which the generator can readily access and which it would likely access for normal commercial hedging purposes in the absence of a FiT CfD.

(a) Intermittent

239. For intermittent generation, the MRP should be based on the short term/prompt markets. The use of a longer dated period would pass too much risk to the generator as they would not have a useful view of output so would not be able to sell the volume, which they would want to do to hedge their output as close to the reference price as possible. If the generator cannot align their despatch profile with power sold against the MRP (i.e. the price referenced in the FiT CfD is on a different basis to the price a generator eventually realises), an element of "basis risk" is introduced into the mechanism.

240. Solely from a perspective of financial certainty, investors are likely to favour an MRP as close to real time as possible given the inherent variability of intermittent generation. However, while this might suggest a half-hour ahead spot price index, it would be difficult to justify such an index:

- There is no incentive on the generator to actively manage any of their output into the market; they would simply sell power very close to delivery – akin to spilling. This would not provide any information to the System Operator (SO) in terms of a potential despatch profile leading the SO to hold additional reserve contracts in order to ensure security of supply;

- In the current GB markets, no useful within-day half-hourly index exists. The APX does publish half-hourly prices but they represent a basket of time periods from 7 days ahead for the power delivered in that particular half-hour – i.e. not a mirror of trades done for the half-hour alone; and
- The within-day market will in all likelihood remain a very thin market heavily influenced by distressed buyers and sellers seeking to avoid exposure to the balancing mechanism. This market will therefore most likely remain extremely volatile and is not a robust representation of the value of spot power across the industry.

241. For these reasons, the use of intra-day markets in the choice of MRP has been ruled out. **The proposed approach is to use a day-ahead index price (the price for delivery the following business day).** Whilst this introduces some basis risk (compared to a half-hourly index) on balance we believe the day-ahead better serves the system and the market better, it still provides sufficient certainty to investors. There are several reasons for this choice:

- Day-ahead is the time by which an intermittent generator will have some view of what they may generate tomorrow – given existing wind forecasting techniques.
- The GB day-ahead markets are currently relatively liquid and already used extensively by intermittent generators. Furthermore, the existing markets provide clip-sizes (i.e. volumes available to trade) which are both small enough to facilitate smaller intermittent generators but also provide sufficient market depth for larger deals to be struck (refer to discussion on price source).
- Generators are likely to choose to trade in the market that a FiT CfD is settled against, thereby minimising their basis risk. It should be recognised that issuing FiT CfDs in large quantities is likely to direct market liquidity toward the chosen settlement reference price. The promotion of liquidity into the day-ahead market is therefore likely to be beneficial to the general health of the GB power market. The development of day-ahead liquidity will improve the robustness of a representative index. As this becomes recognised it is likely that market participants are more likely to be willing to write financial contracts against this index helping to deliver liquidity further along the curve (P4).
- Whilst there is undoubtedly inaccuracy between the day-ahead and point of delivery, this basis risk can encourage better forecasting techniques to be developed over time.

242. There is a choice as to whether the day-ahead baseload price should be used or hourly prices published by the N2Ex from the day-ahead auction. The use of hourly prices would allow an intermittent generator to reduce their basis risk by selling a shape representing their actual forecast at the day-ahead stage rather than an average of their forecast into the baseload product. This would reduce the need for a generator to have to refine their hedges to match their output profile. However it should be noted that the production of hourly prices from a daily auction is a relatively new process in the UK market so are mindful that it may not develop in the way anticipated and fall by the wayside. Making this decision now may not therefore be prudent.

243. Further, we note that other European markets which have applied support instruments with a link to the electricity price (including Denmark and the Netherlands), the chosen MRP is in general a day-ahead market price.

(b) Baseload

244. In the case of baseload plant which can be expected to have a more predictable output than other forms of generation, the forward market is more relevant as the basis for the MRP rather than the prompt or spot markets. A forward market reference under the FiT CfD:

- Retains availability and reliability incentives to optimise production and maintenance activities by leaving the generator exposed to short-term traded markets through to prompt and delivery timeframes (P3);
- Preserves normal commercial incentives for active participation in forward markets in order to hedge the MRP (P4); and
- As far as possible avoids distortion of market liquidity and is consistent with Ofgem liquidity improvement initiatives which also focuses on the forward segment (P13 and P15)
- Whereas a forward market MRP would place unmanageable (and therefore inefficient) risks on intermittent generation, the converse applies to baseload generation. Applying a short term reference would transfer risk to consumers that these generators are better placed to manage and potentially remove participants (and positions) from a market segment in which they would naturally operate.
- By selling physical power forward the generator has an incentive to ensure reliability and to efficiently plan periods of maintenance (in a similar way that averaging a day-ahead price does – see next section). If the plant is not operating the generator does not receive payments under the FiT CfD but more importantly they are exposed to the market price in that they will be required to buy back the power for days they are not operating and where they had already sold forward. Evidently the generator improves revenue by avoiding high priced periods for such repurchasing needs.
- The time period proposed for the MRP is the 12 months prior to the year of delivery. In the current GB market the longest contract, with adequate liquidity, is a season. We recognise that calendar contracts are now quoted more often in GB, but the market remains dominated by seasons[21]. Therefore, for this FiT CfD an average of the summer and winter prices are most relevant as an MRP. This has the advantage of removing the seasonal effects of pricing, so smoothing the payments under a FiT CfD. It is also easier to manage from a cashflow perspective given the vast majority of consumers bills are also uniform and do not have different prices across the year and enables the generator to spread their sales over 12 months rather than six enhancing market liquidity over a longer period.

3.13.4.ii Averaging Period

(a) Intermittent

245. **The proposed approach is not to average the source price**. Averaging the source price over a period to create the MRP does have some benefits in directing maintenance decisions to low

[21] In GB, the main driver for liquidity in seasons is the liquid products in the gas (NBP) market.

price periods. However, this would introduce additional basis risk to the contract since the intermittent generator will not have any certainty in its ability to capture the average price (P3). In any case, a FiT CfD provides an incentive for an intermittent generator to maximise their output and hence remain available as much as possible. Further, maintenance for these forms of generation naturally falls outside of the winter period when the access to the plant, often located away from major routes or even offshore, is easier.

(b) Baseload

246. The proposed approach of using a year-ahead reference achieves the same efficiency benefits as averaging the price source over a year.

247. In contrast to more unpredictable plant, it is reasonable to introduce basis risk to the generator between the time of selling the power in the forward market and delivery. In terms of efficiency signals such as carrying out maintenance at the right time, assuming the generator has hedged/sold their output on a forward basis in line with the MRP, using a year-ahead forward price has the same effect as averaging the day-ahead price. A baseload generator will and should have reasonable confidence in its ability to capture and an incentive to "beat" the average price across the year[22]. This structure clearly incentives reliability at periods of high prices when the system is likely to have a tight margin.

248. If a baseload generator has no incentive to carry out maintenance at the right time, there is the potential for inefficient dispatch leading to higher prices (as plant with a higher marginal cost is brought onto the system) and consequently higher costs for consumers. It would also mean that FiT CfD top-up payments would be higher: generators would be receiving less revenue from the wholesale price if they are not provided with an incentive to generate when prices are high. This would in turn have implications for public finances.

249. The impacts of averaging on a nuclear generator can be illustrated by looking at historical day-ahead electricity prices (2004 to 2010). This shows that:

- if maintenance were carried out at times when prices were at their highest, instead of at their lowest, revenues for a nuclear generator would have been 2% to 7% lower. FiT CfD support would therefore have been 2% to 7% higher for this plant (4% on average).
- If maintenance were carried out at time when prices were around average instead of at their lowest, revenues for a nuclear generator would have been 0.6% to 1.6% lower. FiT CfD support would therefore have been 0.6% to 1.6% higher (1% on average).

3.13.4.iii Price Source

(a) Day-ahead for intermittent

250. The lack of a defined single platform which dominates the GB market , compared to e.g. NordPool, which could provide a reliable, robust and reflective price represents a practical challenge (at least for the initial FiT CfD contracts) and increases the complexity required in a FiT CfD for the MRP.

251. The selection of price source is principally a function of what is available currently and what may develop in the future. The issuance of FiT CfDs to the market will naturally direct liquidity

[22] i.e. generate when prices are high and only need to buy power back already sold forward to cover outages, planned or forces, when prices are (or anticipated to be) lower)

into parts of the market on which the MRP is sourced as generators will most likely sell at the MRP where possible as an efficient hedge. However, we cannot rely on FiT CfDs perpetuating adequate change to the market themselves. To represent a practical offering to potential investors, it needs to be clear how these contracts will be settled in the current market as well as how the MRP will be adapted to reflect future market developments (P14).

252. While greater market integration (whereby separate markets are linked to determine efficient cross-border flows), increased interconnection (e.g. via BritNed), and Ofgem initiatives may improve liquidity, it is important to recognise that the lack of a defined single price reference represents a real and practical challenge at least for the initial offerings. At present, price discovery in the GB markets is broadly limited to three groups:

- Price reporter's (e.g. Argus, Heren) assessments;
- The LEBA Index, an Index created from actual OTC trades; and
- The index published from trading on the N2Ex or APX, neither of which are as yet well established.

253. The London Energy Brokers Association, LEBA, has provided an index for power since 2003. The Working Days Index is created from all OTC transactions undertaken in the market between 07:30 and 17:00 on each trading day, through LEBA Brokers (which includes all of those offering GB Power contracts at the time of writing) for delivery at the day-ahead stage. It is therefore an Index (from actual trades) rather than an assessment (which would be created by asking market participants directly where they see the price at a fixed point, this is therefore subjective and does not cover all deals done on the day but fix a specific point in time usually towards the end of the trading day).

254. The other relevant marker is the day-ahead index provided by the N2Ex exchange. The exchange has been operating since early 2010 and has attracted a growing number of counterparties. However there are only 22 signatories to date, significantly less than around 300 that can trade on NordPool. N2Ex publishes two indices each day:

- An Index based on a continuous traded market; and
- An Index based on a daily auction held each morning for delivery day-ahead.

255. As indices, they are both based on actual deals. It could be expected that the volume in this market will grow, given the industry support to date, and if it is selected to underpin new contracts (such as these FiT CfD instruments) then liquidity is likely to improve and grow further.

256. Both the LEBA and N2Ex indices are published with both a price (in £/MWh) and a volume of deals (MWh) contributing to the index. This allows a volume weighted average of the two to be constructed resulting in a strong reference price representing the majority of volume currently trading in the market. The LEBA index currently has the most volume, but N2Ex is likely to grow. There may be other indices which exist now (e.g. APX) or which develop that can become suitable for use in the FiT CfDs. An exchange based price is preferable due to:

- Ease of access (one contract rather with the exchange is needed rather than bilateral contracts required with each counterparty);

- Credit terms are also simpler with a single credit relationship, equal for all participants, rather than different terms between different counterparties. Also, collateral is posted on a net rather than gross basis, making it easier for smaller players to access.

257. Notwithstanding the attraction of exchange based indexes, in the existing GB market it would not be sensible to rely solely on N2Ex given the majority of trades are undertaken elsewhere. Additionally, volume could move to other platforms with greater liquidity. It is important for parties not to be able to manage their trades so that high prices appear in one Index and low in another or vice-versa to maximise any payment from a FiT CfD (recognised that traders are likely to remove arbitrage opportunities that appear). Even if parity of pricing is observed between platforms it is important for the MRP to be inclusive to prevent generators from gaming by e.g. trying to create spreads between prices across different platforms (selling at a higher price on one platform to beat the MRP). Market price assessments are not our preferred option as they are less reliable and may lack of market coverage. There are not many products in the market at the moment which allow a generator to hedge basis risk between the exchange prices and the LEBA index so the generator may need to be able to access all markets[23]. A generator may deem this risk to be small enough not to impact their hedging process (and given market efficiency to average out over time).

258. An initial proposal is therefore that:

- The reference price initially be calculated as a composite being the volume weighted average of the LEBA and N2Ex indices; and
- The contracts include an in-built mechanism for revising the MRP index to ensure it remains the best representation of market day-ahead prices. It is proposed that this mechanism be managed and supervised by an independent trustee, as further described in Section 3.13.7.iii .

(b) Year-ahead index for baseload

259. At present, price discovery in the forward GB markets is broadly limited to price reporters' (e.g. Argus, Heren) assessments. A number of attempts have been made to list GB futures products and create liquidity on exchange platforms in the past (e.g. ICE) but thus far these have not been successful in becoming an established part of the market. Nasdaq/OMX has recently launched Financial Futures based on the daily index, but this is as yet is unproven.

260. The proposed approach is that the MRP be calculated as the average of the Summer & Winter EFA Baseload contracts calculated each business day in the year (Apr-Mar) for the following year's delivery based on OTC, Market Assessments and Exchange Transactions. Given the anticipated changes in GB market liquidity due to Ofgem initiatives over the coming years, in advance of the time when these FiT CfDs operate we believe that indicating the source of prices, based on current price publications, in detail today would not be useful. However, a robust process should be in place as part of the MRP parameters in the FiT CfD for independently determining the price source to be a more robust and attractive solution.

261. Developers that wish to access these FiT CfDs early during the transition phase can assess their likely cost of capital on the basis the MRP will be reflective of the prevailing weight of market transactions (as monitored by Trustee).

(i) Averaging the price source

262. It is proposed to average the price source under the baseload FiT CfD as focussing the output of a number of generators with similar FiT CfDs at a single point in time could lead to

[23] In order to capture the LEBA Index a generator would need to either sell power throughout the trading day to represent a broad average of the day's prices or sell their power to a third party which uses the LEBA Index for settlement.

distortions in market price. If the MRP was the price taken on the last day of the year preceding delivery, then we could expect to see large volumes sold on this one day to ensure generators keep within their risk limits, likely depressing the market price. It could also allow gaming by selling power before the end of the year and then buying back volume at a lower price[24]. The result of this would be a larger payment to fill the gap between the reference and strike prices in the FiT CfD.

263. To avoid this we propose averaging the MRP over the year prior to the year of delivery. The MRP would be constructed from the average price, during a particular year, of forward prices for power to be delivered in the following year. As an example for each trading day during 2011 the forward index price for power to be delivered in 2012 is taken and averaged. At the end of 2011, this average becomes the MRP for power delivered in 2012. During 2012 the price is formulated for delivery in 2013 and so on.

264. In order to hedge their exposure to the MRP and to ensure they receive the Strike Price for their power, a generator would need to sell their power into the forward market on each trading day in the year prior to delivery. For example, the operator of a 1GW plant would split the power into 200 (assume 200 business days) lots of 5MW. On each day one lot would be sold so that by the end of the year the entire physical volume had been sold and the price achieved would be equivalent, allowing for intraday price movements, to the average of the price for the year.

265. This structure affords the opportunity to sell forward over a period of time against the long term reference price, locking in the strike price, as opposed to trying to sell a large volume (e.g. 1GW) into the market in a single tranche – potentially depressing the market price.

266. As before, these generators retain volume risk between the forward sales and delivery incentivising reliability and availability at times when market prices are high and planning their outages for periods when prices are expected to be low.

3.13.4.iv Using auctions to set the market reference price

267. Rather than relying on a defined index, the contract could oblige the generator to sell volume forward for the year ahead through an auction with the clearing price being used as the market reference price for the FiT CfD:

- It is envisioned that the annual volume would be sold in 12 monthly auctions in the year prior to delivery;
- The product would be a simple baseload power contract for the following year (structured to match commercial products available in the market at the time);
- The auction would call for bids for a defined quantity of power and hence bidders would bid the price at which they would be willing to buy that volume. Bids would be cleared from the top (i.e. high bids going first) and the auction clearing price would be the lowest price which enabled the target volume to be sold;
- Since the FiT CfD follows metered generation, the volume sold via auction (which would be sold in fixed blocks) would need to be below the expected load factor (e.g. 80% of rated capacity);

[24] There was some suspicion of this in the early EU ETS auctions when large volumes were offered for sale on a single day in a relatively thin market with the perception price fell prior to the auction only to recover subsequently.

- There would be no reserve price as the seller (the FiT CfD generator) is covered under the FiT CfD contract.

268. There are a number of advantages to this approach:

- It avoids having to specify an index today for a contract which only becomes operational in the future;
- The main requirement for a successful auction is sufficient demand for the product. It is very difficult to see any future market environment in which there will not be buyers for a simple base load strip;
- The success of such a simple product will not be very dependent on other (less predictable) market developments. Whether the GB market then has established and liquid exchanges or not, a well attended auction is likely to deliver competitive price signals reducing gaming potential and Government risk. Auctions can adapt to the surrounding market environment and the product structured to match existing commercial products (in whatever market exists at the time). Hence, auctions offer a strong element of inbuilt future-proofing;
- If the mandatory auctions under consideration by Ofgem as a means of improving market liquidity have been implemented and continue to operate, the FiT CfD auctions could be included within that mechanism or sold via existing well established exchanges (i.e. N2Ex). Either way, these auctions would support the FiT CfDs while also helping the market in terms of liquidity and transparency;
- While FiT CfD generators would not be prevented from buying back auctioned volumes, the initial auctioned volumes would leave them with (firm) forward contracts preserving market reliability signals;
- Auctions of a simple baseload product are easy to conduct and monitor. They could be augmented by, for example, an independent Trustee (to confirm/validate prices) as a further guard against gaming and anti-competitive behaviour.

269. The main disadvantage of mandated sales is that integrated operators would be forced to treat the FiT CfD covered plant as a stand-alone proposition. It would be difficult to integrate it within a wider portfolio without buying back volume in the auction. While the other alternatives all suggest and encourage certain actions and behaviours in order to achieve and hedge the reference price risk, large players would not be free to optimise the FiT CfD plant within the wider portfolio. The impact on a portfolio player of mandating selling is considerable and may swamp the other benefits outlined above. This option remains under consideration.

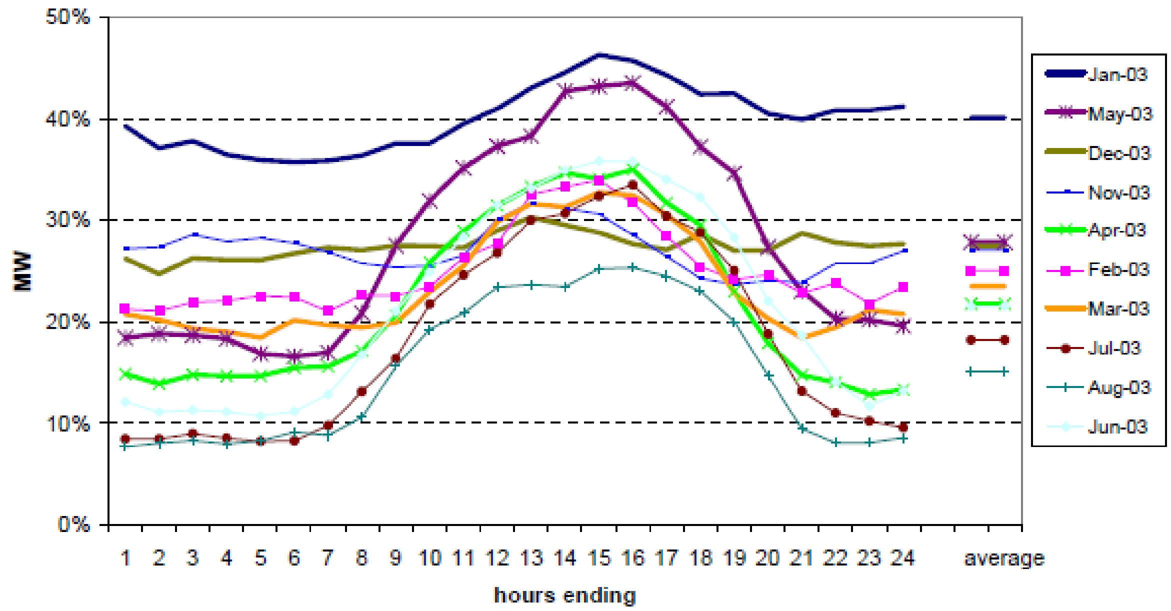
3.13.4.v Revenue Realisation

(a) Intermittent

270. For a FiT CfD to be effective, a generator needs to be able to sell power at (or close to) the MRP. It must be “capturable”. If the MRP cannot be achieved then the net income will not equal the strike price as the generator will not receive the MRP element if they cannot achieve it. For an intermittent generator there is recognition that by their very nature hedging forward is a near impossible task. However, this needs to be balanced with selecting a suitable market segment.

271. The proposed approach uses a day-ahead baseload measure for the MRP. Although wind output is variable, there are systematic variations over hours of the day (and months of the year) that impact the value of its output. We recognise the basis risk created in the difference between the "flat" (time-weighted average) baseload price and the shape an intermittent generator will actually produce. If the generator sold flat power at an average of the forecast it would need to buy back power for periods where output was lower than the average and vice versa. However, evidence suggests (see Figure 10) that on average a wind generator in the UK produces more power during the day than at night. This positively correlates with demand and therefore intraday prices. The generator could, on average, be expected to beat the average day-ahead baseload price by selling more peaks at a higher price and selling fewer (or buying back) off-peaks at a lower price rather than meeting the time-weighted average reference price. This effect could be expected to be reflected in lower strike prices required by the developer.

Figure 10: Monthly average of hourly GB on-shore wind capacity for 2003



Source: "Market Behaviour with Large Amounts of Intermittent Generation" Green and Vasilakos (2010)

272. In any case, the structure we propose allows the basis risk between selling at the MRP and actual price achieved for the output of the generator, given intermittency, to be covered by a balancing payment. As such we believe the realisation of revenue is possible through this FiT CfD instrument design.

273. While the use of day-ahead prices leaves some risk with the intermittent generator, we consider this to be meaningful market exposure necessary to encourage improvements in forecasting and predictability over time.

(b) Baseload

274. For these classes of predictable generation the structure outlined to sell forward is achievable to ensure realisation of revenue. The MRP will not be met where a generator takes a

planned outage (the incentive is to do this when power prices are low) or forced outage (the incentive is on reliability to ensure operation at times when power prices are high). However this risk is left with the generator which may seek compensation through a higher strike price in compensation for increased cost of capital.

3.13.5 Contract Volume

(a) Intermittent

275. Of the three alternatives outlined in section 3.11.4 , the inherent volume uncertainty of intermittent generation means that our proposed approach for this class of generation is to settle the FiT CfD against metered output.

276. A firm (fixed) contract volume would create risks for intermittent generators which they would not be able to manage or otherwise respond to. Since the generation from such plant is entirely uncertain ahead of delivery, the generators would have no means of matching output to the contract. The alternative of paying difference payments on the available capacity would necessitate an intensive monitoring process in particularly in view of the potential number of installations in this class of generation. Hence, the most practical option is metered (outturn) generation. This has the added advantage that support is only paid when the plant actually generates.

277. For units embedded within local distribution networks, metered output would be defined as the generation as measured by the site meter. For plant which are BM units, and therefore potentially subject to SO instructions, the metered output is not necessarily the volume the generator in question was able to produce. In the event the SO has constrained the generator, they would not get their FiT CfD payment for the constrained volume. For those periods where the generator is constrained, it is proposed that the generator is paid under the FiT CfD on the basis of their declaration to NG prior to the intervention. In a future scenario which consists mostly of a mix of inflexible baseload and intermittent generation the ability of the SO to turn down intermittent (with little restart costs) becomes important. The SO would want to turn down wind before turning off nuclear (both on cost grounds and ability to start back up again).

(b) Baseload

278. For this class of generation there are two options for determining the volume in the contract: metered output and firm volume. This decision has been left open in the White Paper.

279. The use of a firm volume FiT CfD has difference payments that are calculated for an agreed fixed number of MWh[25], rather than based on actual generation. A firm volume contract is therefore financial and technically disconnects the contract from plant performance; it is exactly this feature which provides strong signals for reliability and optimisation of running regime. If the generator is not operating, it would still receive or pay difference payments. However a portfolio player could use another generation unit to manage the volume and price risk form the FiT CfD as the contract is not plant specific and this form of contract may lead to gaming.

280. The sharp reliability signal provided by a firm volume contract is similar to the signals they have in the current BETTA market (under physical contracts). Since this signal can be very penal, firm contract volumes will typically be set at or a bit below the average expected load factor

[25] The form of contract is often referred to in terms of the number of MWs, with an assumption that the plant is running all the time.

taking account of both planned outages (maintenance) as well as the likelihood of forced outages. Hence, the daily contract quantity will be below actual generation when the station is operating (and much above when not). This un-contracted volume provides a further incentive to optimise and capture market prices when they are high.

281. There are however two potentially significant drawback of adopting firm volume.

282. Firstly, the strike price in a "standard" two-way commercial contract is typically set against an expectation of (average) market prices (i.e. current forward curve). Hence, there is no expectation of a systematic bias in direction of difference payments at the time of entering into the contract. However, in the case of the LC instrument, the LC support is included within the strike price and this price is therefore expected to be above the average MRP, at least initially. Since the LC FiT CfDs are struck above the current market price, net difference payments will be expected to exhibit a bias in favour of the generator.

283. If settled on a firm volume basis, this bias would potentially leave the contract exposed to what could seen as undesirable effects. If the generator can be quite certain about being in receipt of difference payments for extended periods of time, the incentives for actually generating are diminished as the generator anyway receives income under the FiT CfD. Hence, in a low price scenario consumers could be paying for LC support without getting any LC generation contribution. In contrast, if the two-way FiT CfD is settled against metered output, the generator only receives support for the volume they produce.

284. Secondly, a firm volume contract is truly a financial instrument which is independent of physical production. While a commercial firm volume FiT CfD provides strong incentives for a generator to be able to earn the MRP to hedge the risk of having to pay difference payments when price are high, any operating within its portfolio will deliver this hedge. Hence, there is a possibility that a portfolio generator in periods could use other plant (e.g. plant supported through the RO) to hedge the FiT CfD. Whilst this may be the economically rationale choice, it may not align with decarbonisation objectives.

285. A 'sub' option is contract volume representing metered output as is the case for intermittent. However, where output is modified by the SO, we would use the volume declared by the generator as the basis for FiT CfD settlement rather than the actual output.

(i) Dispatch efficiency

286. Firm volume and metered output also have different impacts on dispatch efficiency. Metered output would provide an incentive for baseload plant to run to access support. Using a year-ahead reference price limits the extent to which they would keep running, even when the price is lower than they marginal costs. For example if the difference between the strike price and reference price for a nuclear generator were £20/MWh and its marginal costs were £5/MWh, it would continue to generate until prices dropped to -£15/MWh.

287. Under a firm volume contract however, plant does not need to run to access support and should therefore choose to turn down if the price was lower than their marginal cost. If a generator had sold forward to minimise basis risk, they could fulfil their obligation through buying electricity on the market (at lower cost).

(c) Flexible

288. Metered output is not appropriate for plant providing flexible LC capacity which needs to be able to respond to variations in system demand. Indeed, if the obligation to pay difference payments under the one-way contract was metered output, the generator could in principle decide not to operate even when prices are high. They would still receive compensation for fixed and capital costs through the fixed payment. Therefore, difference payments under the proposed one-way contract will be settled on a firm volume basis to ensure that the generator has an incentive to provide available capacity during times of high prices.

3.13.6 Fixed payment

(a) Intermittent

289. By their nature intermittent generators cannot provide reliability to the system and cannot provide system security (although we recognise that the SO rates such plant at 10% load factor – this is on a system-wide basis rather than for individual generators).

290. Indeed it is the intermittent generators that are likely to contribute to tight system margins by not providing power at these times. It would not be acceptable to make a fixed payment (related to capacity) to an intermittent generator who could not be relied upon to improve system security when they cannot control their output (except for taking the decision to shut down).

(b) Baseload

291. The nature of a two-way FiT CfD negates the need also to have a fixed payment made to the generator. Providing the incentives are there for a generator to operate at times of low system margin (high prices) where this is in their control, an additional fixed payment is not required.

(c) Flexible

292. For a one-way FiT CfD to be attractive, the removal of the payment to the generator has to be compensated for. This is achieved by making a fixed payment to the generator, which covers all the fixed costs that the generator has. It is important to ensure existing market price signals for both commercial optimisation and reliable operations are preserved so the contact has to be associated with a firm volume contract (see previous section).

3.13.7 Other terms

293. In addition to the terms discussed in the previous sections, the contracts will include a number of common clauses. These terms are discussed below but at this stage there are no preferred options.

3.13.7.i Obligation to build

294. FiT CfDs will require mechanisms (e.g. penalties) to ensure that the award of a contract is followed by development and construction. Otherwise, such contracts could be regarded as (free) options to build at any time in the future.

295. Regardless of the specific mechanism for contract award and allocation, it is generally desirable to move this process as far forward in the development cycle as practically possible. Otherwise, there is a risk of placing undue risks on developers by requiring large investments in

advance of contract award. Contracts should therefore include an obligation to build within a maximum time frame from the award of the contract. Such an obligation would need to be backed by sufficiently strong incentives to avoid gaming. This could be achieved, for example, by requiring up-front security payments from the bidder at the time of entering auction/tender.

296. In practice, this could simply be a bank guarantee. In the event of commissioning actually exceeding the contract construction deadline, penalties would be imposed (and funded from the bank security provided). Clearly, developers would likely seek relief from such penalties for delays which demonstratively are not of their doing.

3.13.7.ii Adjustment of Reference Prices

297. It is impossible to be certain about how market indices for power and fuels will develop and their importance in reflecting the weight of the market will change. Hence, the indicated methodology for determining the reference price should be the starting point for inclusion within FiT CfDs. The contracts will also have a mechanism for review of the source of the reference price index. As the relevance or robustness of indices changes or new indices emerge then their contribution to the MRP should be reviewed.

298. At face value, this adjustment mechanism introduces additional (contractual) uncertainty within the contracts. However, without an adjustment clause, investors would need to take a view on the long term validity of these indices and would, predictably, conclude that it is quite possible that they over time will cease to be the best representation of the power or fuel price they were intended to represent. This uncertainty is likely to be more value destroying than a revision clause. However, for the revision clause to work as intended, the contract will need to be very clear about the grounds and process for revisions. In particular, the review mechanism must aim to ensure that:

- The Volume Weighted Price Reference index at all times reflects the best estimate of actual deals across the entire market;
- Any revisions which add or subtract market references in the index are carried out by an independent body (e.g. an appointed Trustee) solely in accordance with the first principle (above);
- Reviews of the validity of the reference price calculation are carried out at defined intervals (i.e. bi-annually or annually), so that neither of the buyer or the seller can influence timing; and
- Independent review of relevance and appropriateness of indexes included in the reference price (i.e.as other OTC price providers/indexes and/or exchange emerge).

299. The most important characteristic of a Trustee is that it would operate independently of both buyer and seller. The role of a Trustee would be to specifically monitor that power price indices used within the FiT CfDs are current and achievable.

3.13.7.iii Settlement

300. Most energy contracts are settled on a monthly basis whether for physical or financial delivery with payment 10 to 15 working days after the end of the month. This eases working capital issues for generators compared to the existing RO and minimises build up of liabilities which might require larger credit support. If the MRP is averaged over a longer period this may not be possible but one option for such contracts could be to settle, say, 80% of estimated

differences payments against the Year to Date average (ex ante) with a reconciliation and final payment in the 12th month. While the current RO operates with up to 18 months settlement, such a long settlement period creates both cashflow costs for the generator and additional credit risk. Assuming that suppliers will collect charges from customers through their normal cycle (e.g. a Quarterly bill or a monthly billing cycle), a significant amount of sums due to generators will sit on the supplier's balance sheet at any one time. In these circumstances, the financial consequences of a default event could be very considerable. Shorter payment cycles will limit this risk and offer the generators improved cash management.

Section 4 Security of Supply

4.1 The rationale for intervention

4.1.1 The scope of the policy and the counterfactual for the analysis

301. There are three different, linked challenges under the general banner of 'security of supply':

- **diversification of supply**: how to ensure we are not over-reliant on one energy source or technology;
- **operational security**: how to ensure that, moment to moment, supply matches demand, given unforeseen changes in both; and
- **resource adequacy**: how to ensure there is sufficient reliable and diverse capacity to meet demand, for example during winter anti-cyclonic conditions where demand is high and wind generation low for a number of days.

302. Wider security of supply policies to reduce domestic demand, maximise existing oil and gas production and ensure resilient markets will address the first challenge. A higher level of intermittency in the electricity system potentially makes the second and third challenges harder. The second should continue to be addressed by the System Operator (SO), National Grid, through the current approach, including the procurement and operation of Short Term Operating Reserve (STOR). The Capacity Mechanism would address the third problem.

303. In order to assess the impacts of any policy, it is necessary to be clear about the counterfactual. What does the world look like into which any intervention to promote security of supply is introduced? In this analysis, interventions are assessed in a world which has EMR low-carbon support, described and assessed previously. Therefore the Do Nothing scenario, used to assess interventions to increase security of supply, include low-carbon support. The reason that these policies are in the counterfactual scenario rather than only including currently agreed policies is because the Capacity Mechanism is envisaged as part of a package of EMR reforms. There is no suggestion that a Capacity Mechanism would be introduced in the absence of low-carbon support either in the form of FiT CfDs or Premium FiTs. This is the rationale for having a Do Nothing scenario for this section which includes other EMR policies.

304. In addition, Ofgem is currently progressing reforms to the current energy market. These proposed reforms, a combination of changes to cash out arrangements, and efforts to improve liquidity are discussed in more detail below. The counterfactual used here assumes that these reforms deliver a cash out regime that is cost reflective, and significantly improve liquidity. The Redpoint Energy model which has been used to quantify the impacts of the options assumes a liquid market, and a cash out regime where prices rise to VoLL when there is scarcity in the market.

4.1.2 Rationale for intervention

305. This section sets out the rationale for any intervention to provide increased security of electricity supply. This includes the importance of security of supply and the notion of an optimal level of security of supply. The problems associated with delivering this level of security with the current energy market are set out. Looking to the future, Ofgem's proposed reforms to

the energy-only market should help increase security of supply, but these will not be sufficient to guarantee the desired level of security of supply. Evidence from modelling is presented which suggests that even in a perfect energy-only market, we could still expect reduced security of electricity supply compared to today. Given this, and the fact that there is a risk that outcomes will in fact be worse than those modelled, there is a rationale for intervening to increase security of electricity supply.

4.1.2.i Current arrangements and the optimal level of security of supply

306. To provide secure electricity supplies, supply and demand must balance at every point in time. In the GB electricity system, generators and suppliers are incentivised to ensure this by the requirement to pay imbalance charges (the cash out price) if at ‘gate closure’ (one hour before the despatch period) they have not contracted sufficiently to cover the amount they actually generate or supply to consumers. After gate closure a centralised body (the System Operator (SO), which is National Grid) takes responsibility for ensuring the system as a whole remains in balance. As part of this, the System Operator gives contracts for a small amount of generation or demand side response to be available for this residual balancing role. Annex D gives an introduction to the current arrangements.

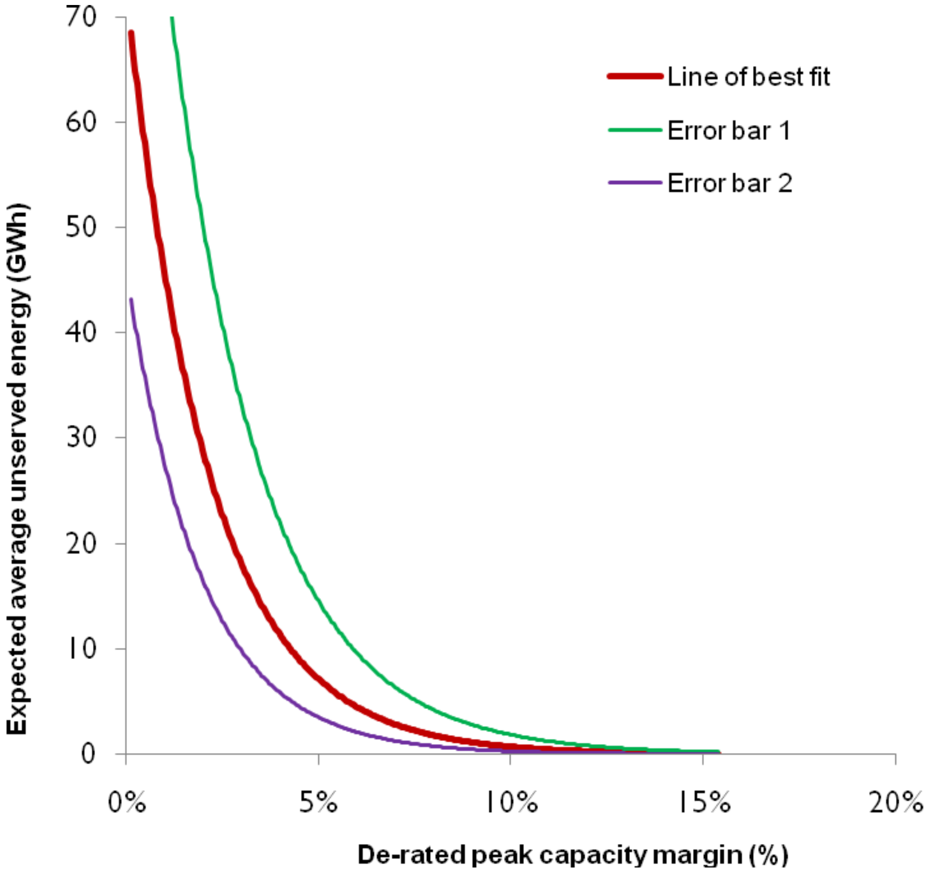
307. Security of electricity supply is a key goal of the design of any electricity market. Historically the UK has benefited from robust security of supply as a result of our competitive market and strong system of independent regulation. An indicator of security of supply is the expected energy unserved (EEU). Energy unserved is the most obvious cost associated with a reduction of electricity security of supply - it is a combination of the likelihood of an involuntarily interruption and the likely size. A proxy for this is the de-rated capacity margin, which is a measure of the excess of total available de-rated generating capacity[26] above peak demand. The relationship is illustrated by Figure 11. EEU includes both energy un-served because of voltage reduction[27] and that due to outages. Some context can be gained from looking at the EEU from faults on the network e.g. trees falling on power lines, which have been estimated at around 12GWh of outages per year[28]. The EEU from generation related problems has been near to zero in recent years.

[26] De-rating involves reducing the total installed capacity to take into account the expected availability of the capacity.

[27] 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.

[28] Dynamics of GB generation investment, Redpoint (2007)

Figure 11: Relationship between de-rated capacity margin (%) and expected energy unserved



Source: Redpoint Analysis

308. There is a trade-off between the cost of new capacity and security of supply. There is an optimal level of security of supply at which point increased investment in generation capacity becomes more expensive than the value of the marginal reduction in energy unserved. Estimates of this optimal level are highly uncertain and depend on estimates of the costs that consumers place on supply disruption. This cost is known as the Value of Lost Load (VoLL). Some estimated ranges of VoLL are between £5,000-30,000/MWh[29] but the upper part of the range could be higher, for example if there are additional macroeconomic costs.

309. Figure 11 also shows the asymmetry in the relationship between the de-rated capacity margin and the expected level of energy un-served. At low levels of margins the supply risks increase significantly, while at high levels there is little change to supply risks from incremental changes in margins. Not only is there a non linear relationship between security of supply and de-rated capacity margins, it is also important to note that the de-rated capacity margin is effectively locked in, several years before the day (because of the lead times involved in new investment). Given the uncertainty over the conditions that will be present on the day, society may prefer to invest more rather than less, in order to insure itself against the risk that the conditions that emerge, see de-rated capacity margins which are lower than the desired level at the time of the investment.

[29] Oxera report "What is the optimal level of electricity supply security", (2005)

4.1.2.ii There are problems with the current electricity wholesale market which provide a rationale for intervention to provide increased security of supply

310. There are a number of market failures which exist in the electricity market which mean that investment in electricity generation is likely to be sub-optimal from society's point of view. These market failures are a well known theoretical feature of electricity markets and one would expect them to be present to a greater or lesser extent in GB's market. We note however, that the extent to which these market failures will in practice lead to insufficient investment is very unclear. We are therefore making recommendations on the basis of a *risk* of an investment shortfall, rather than a quantified *forecast*. The market failures are listed below as follows:

1. That reliability is a public good.
2. That prices in the energy-only market do not send the correct market signals to ensure optimal security of supply.[30]
3. That there are barriers to entry in the electricity market which provide an incentive in both the short and long term to under-invest in sufficient capacity.

(a) Reliability is a Public Good

311. Reliability is non-rivalrous and non-excludable because it is not currently technologically possible to selectively disconnect consumers. Therefore consumers cannot buy reliability for themselves without providing it for everyone else. Since consumers cannot purchase reliability for themselves, there is little incentive for generation companies to provide it. If the demand side were flexible, and responded to prices, then this problem would be mitigated as customers could choose the electricity price at which they would wish to disconnect themselves. However, this sort of demand side response is currently limited,[31] so this problem remains.

312. The rules and regulations which govern an energy-only market can in theory deal with this by allowing prices to reflect the costs of providing energy, and at times when the system is short and there is energy unserved, allowing prices to rise to the average value of lost load. However, in practice, achieving such an energy-only market is very difficult and there is likely to be a problem of "missing money" leading to sub-optimal levels of investment and a lower than optimal level of security of supply.

(b) Prices do not send the correct market signals

313. Ofgem highlighted the risk of "missing money" in Project Discovery.[32] There are three reasons which contribute to the problem of missing money. First, that the System Operator takes actions in the balancing market which lower the cash out price compared to the case where they do not take these actions; second, that the current method of calculating the cash out price does not represent the marginal cost of generating electricity and third, that the electricity regulator will not allow prices to rise as high as VoLL.

[30] Some of the reasons for this might be classified as regulatory failures rather than market failures.
[31] National Grid have estimated that there is a total of 445MW of demand side response in STOR. In addition, there is some demand side response estimated at 1.5GW involved in avoiding TRIAD charges.
[32] Ofgem, 2010

314. The System Operator, National Grid, can currently take a number of actions in the balancing market.[33] The intention is that any actions taken by the SO are reflected back into the cash out price. In practice however, much of the cost of such actions are not reflected in the cash out price[34]. Hence this is likely to be a source of missing money.

315. The current rules which govern the cash out price do not truly reflect the marginal cost of generating energy. This results in weaker incentives for participants to ensure they are in balance than would otherwise be the case. The cash out price is calculated from the weighted average of the 500 MWh of the most expensive balancing actions taken by the system operator, rather than reflecting the marginal cost of balancing the system (the most expensive balancing action). Market participants are less likely to invest in additional generation or demand side response if the cash out price is not truly marginal. In addition, if the prices in short-term markets do not fully reflect the scarcity of generating capacity, forward prices will also be muted.[35]

316. A final and important reason for missing money is that the electricity regulator Ofgem, as a result of information asymmetry, in some circumstances may have difficulty in determining whether a high price in the balancing mechanism is the result of "good" economic reasons (to cover the fixed costs of a low load factor plant) or for "bad" economic reasons. The incentive to withhold energy, within the limits of competition law, at times of system tightness is an important and well known feature of electricity markets. Generators which have a significant share of the electricity generation market may be able to reduce production in one plant thereby losing a small amount of revenue but take significant advantage of the high prices that result due to those actions. This feature of electricity markets can lead to pressure from the regulator to avoid these high prices. This downward pressure on prices can blunt the investment signal to new entrants. Note that it is not even necessary for this to be true in reality, only for investors to believe that there is a chance that it is true for it to lead to sub-optimal investment decisions.

317. These market and regulatory failures which produce "missing money" will exacerbate the risks to security of supply when there is a significant amount of low-carbon intermittent generation on the system. This is because it will be necessary to have flexible generation to meet demand when, for example, the wind isn't blowing. This flexible generation will cover its costs by running only a small fraction of the time and therefore will be reliant on very high prices at these times. Moreover even if prices can rise high enough, the revenue uncertainty for such plants will be large, particularly if there's uncertainty around them being able to capture those high prices as they occur. This means that investment in such flexible generation may not be forthcoming - thus posing risks to security of supply.

(c) Barriers to Entry

318. Another source of market failure is the presence of barriers to entry in the wholesale market. A key feature of the current UK arrangements is a lack of liquidity in wholesale

[33] These actions includethe procurement of Short Term Operating Reserve (STOR) as well as a number of ancillary services including BM Start (warming), Fast Reserve, Intertripping, Frequency Response, and System-To-System Services

[34] Ofgem, Project Discovery

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

electricity markets.[36] This lack of liquidity means that potential new entrants in the generation side cannot be sure of the electricity prices that are being achieved in the energy market. This makes new investment more uncertain and costly. The lack of trading also means that they cannot be assured a route to market, other than through the volatile and uncertain balancing mechanism. All of which will tend to reduce the potential for new capacity to enter the market. This means that incumbents have a degree of market power. With all other things equal, market power will lead to generators lowering the output of electricity and raising the price of the electricity they produce.

4.1.2.iii Looking to the future, Ofgem has proposed a number of important and helpful reforms, but problems are likely to remain.

319. Ofgem is undertaking two reform processes to improve the operation of the current market: to sharpen the incentives for market players to balance supply and demand through cash out reform, and to increase the amount of electricity traded in the market through its Liquidity project. This section sets out the Government's views on these issues in relation to security of supply.

(a) Cash out reform

320. Electricity is traded in half hour settlement periods. Bilateral trading between generators, suppliers and intermediaries ends one hour before the half hour period in which electricity is generated, supplied and consumed. The SO is responsible for ensuring the electricity system remains balanced within each half hour period. The system can be out of balance when electricity generators or suppliers are also 'out of balance' – that is, when market participants deviate from their declared intention to generate or supply electricity. The SO incurs costs on behalf of the industry for increasing or reducing supply or demand to balance the system.

321. Imbalance Settlement or 'cash out' is the process used to settle differences between financial contracts and physical metered volumes of electricity wholesale market participants. Cash out prices are intended to reflect the costs the SO incurred when balancing the system. The current cash out price may not fully reflect the costs of ensuring demand and supply are in balance and at times may be too low, contributing to the missing money problem described above.

322. In August 2010, Ofgem consulted on whether to undertake a Significant Code Review (SCR)[37] of cash out. Ofgem has identified a number of areas for consideration to improve cash out. The list of issues below is not exhaustive and others may be revealed before and throughout the process. The options are not mutually exclusive.

323. In summary the options are:

- changing to a single or fixed spread cash out price – different cash out prices for selling and buying electricity, as exist currently, provide balancing incentives but create more than one price for what is essentially the same product;

[36] This has been identified by OFGEM as a feature of the GB market. Most recently in: The Retail Market Review – Findings and initial proposals, 21 March 2011

[37] Ofgem introduced the process of SCRs in 2010 as a result of its review of industry code governance. SCRs give Ofgem a leadership, coordination and change initiation role where a number of code changes are necessary in order to address an issue with a significant impact on the achievement of its remit. This allows Ofgem to drive code changes forward in a way it could not do previously.

- changing to more marginal pricing – a scheme closer to marginal pricing should result in more cost reflective prices if system balancing actions[38] can be accurately removed from the price;
- more effective allocation of reserve contract costs – by targeting costs to the period in which the reserve is used this should be more cost reflective[39]; and
- putting a price on the currently non-costed SO actions – customers could be compensated for involuntary voltage reductions and automatic demand disconnection, and these costs included in the cash out price.

324. A more accurate cash out price should make the spot market price more reliable. A more reliable spot market price will in itself improve security of supply by providing greater incentives to market players to invest in development and/or retention of capacity. In addition, some forms of Capacity Mechanism would need a reliable reference price, which could be provided directly by the cash out price or indirectly by influencing the price in the spot[40], day ahead[41] and forward[42] markets.

325. There are risks to be managed in implementing cash out reform, including the risk that if cash out prices become more volatile, there will need to be sufficient liquidity to allow market participants (particularly smaller suppliers and generators) to trade out of imbalance positions. We would expect Ofgem to consider this issue and any related negative impacts on non-vertically integrated companies as part of its Impact Assessment.

(b) Improving liquidity

326. Ofgem announced a programme of work in June 2009 to improve liquidity in the wholesale electricity market. In March 2011 Ofgem published its Retail Markets Review (RMR)[43], which showed that liquidity fell overall in the GB power market over the course of 2010 from an already low base.

327. Ofgem concluded that the market was failing to develop and that action was required. They put forward two proposals for intervention (the Mandatory Auction[44] and Mandatory Market Maker[45]) to provide the electricity market liquidity that market participants, in particular independent market players, require to compete against existing firms and to encourage competition between vertically integrated players. Ofgem considered that their proposals would improve competition and contestability in the energy retail markets to the benefit of consumers. Ofgem's final decision regarding intervention will be reached following the publication of an Impact Assessment by the end of 2011.

---

[38] System balancing actions include balancing locational constraints and second-by-second balancing.
[39] More accurately reflect the costs incurred by the system operator when balancing the system to market participants that are out of balance.
[40] Trading for delivery on the same day as the trade (within day).
[41] 'Day-ahead' trading refers to buying and selling for delivery of electricity on the day after trading takes place.
[42] 'Forward' trading refers to buying and selling for delivery of electricity in the month ahead and after, and may include trades months, seasons and years ahead of delivery.
[43] http://www.ofgem.gov.uk/Pages/MoreInformation.aspx?file=RMR_FINAL.pdf&refer=Markets/RetMkts/rmr
[44] This should help to drive reference prices and support the ability of independent market participants to access the bulk of the wholesale products they need.
[45] These arrangements ensure that market participants are able to trade continuously and mitigate imbalance risks. The obligation is intended to enable independent smaller market participants to manage their risks.

328. We note that Ofgem's liquidity project is ongoing, and seeks to ensure that the wholesale power market better meets market participants needs – including those of independent suppliers and generators.

329. As outlined in the EMR consultation document, a more liquid market could reduce security of supply risks for three reasons:

- a liquid market would give new entrant generators greater confidence that their product could be sold (i.e. reduce off-take risk);
- a liquid market makes for better price formation and stronger investment signals, in particular there is scope for significant improvement in price signals in the forward market (one month-two year); and
- a more liquid spot market means that closing out positions in a long-term contract could be easier, which may lead to more long-term contracting[46].

330. The Government continues to support measures taken by Ofgem on cash out reform and improving liquidity in the market. Nevertheless, in addition, there is a rationale for going further to address the security of supply challenge. This is because a) achieving a theoretically perfect cash out price is very challenging in what is a very complex system, and b) that investors may not find it credible that prices will be allowed to rise as high and as often as they will need to in order to stimulate investment in a future electricity system with large amounts of intermittent generation on the system.

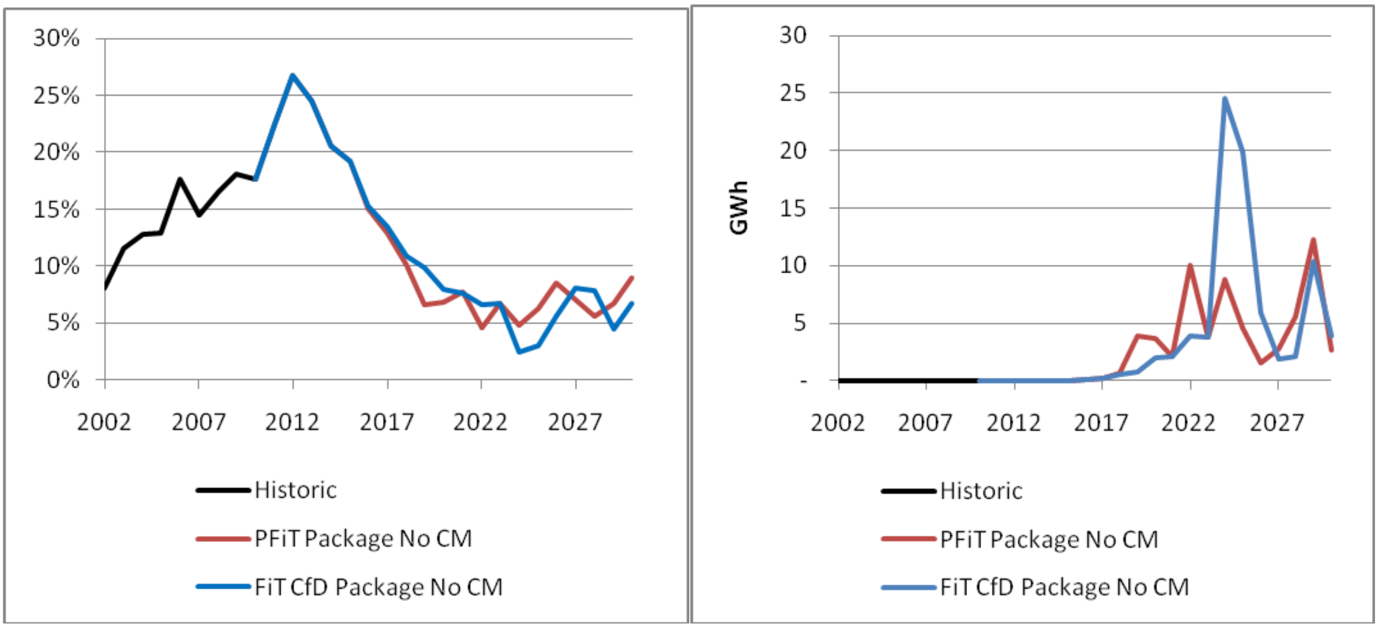
4.1.2.iv Analysis from economic modelling suggests that capacity margins are likely to fall in the early part of the next decade.

331. There is evidence from modelling of the electricity system which suggests that investment in generation, even in the absence of many of the above market failures, will still not be sufficient to avoid energy unserved[47] particularly when the additional EMR decarbonisation policies are introduced. Figure 12 shows the forecast capacity margin and expected energy unserved in EMR scenarios which include either a FiT CfD or a Premium FiT.

[46] Why we need to fix our broken electricity market, special report, Poyry, 2008.

[47] Energy unserved is a measure of energy demand that has not been served as a result of either voltage reductions or load shedding. The EEU from generation related problems has been near to zero in recent years. This compares to approximately 400,000GWh of electricity supplied in 2009

Figure 12: Peak de-rated capacity margin (%) and expected energy unserved (GWh) to 2030 in alternative EMR scenarios



*Margins to 2009 are estimated using DUKES (2010) and Redpoint de-rating factors thereafter based on the Redpoint EMR baseline simulation

Source: EMR Redpoint analysis and DUKES (2010)

332. The years immediately after 2010 are characterised by increasing capacity margins. This is due to a combination of pre-committed CCGT investment coming online with demand being lower than expected as a result of the economic downturn. In reality, much of this increase has in fact been offset by mothballing of CCGT plant, although this hasn't been included in the modelling. Increasing amounts of intermittent generation also has a very important impact on de-rated capacity margins and energy un-served. After 2012, the de-rated capacity margin falls as plant impacted by the Large Combustion Plant Directive (LCPD) and then the Industrial Emissions Directive (IED) retire, and current nuclear plant closes. In the early 2020's margins are particularly low because of the plant retirements and the fact that new nuclear and CCS investment has not yet fully emerged. The de-rated capacity margin between 2019 and 2030 falls below 10%, and below 5% in more than one year under both decarbonisation policies.[48]

333. It is important to note that the modelling is based on a Value of Lost Load of £10,000/MWh, and this price is assumed to be reached in the event that there is energy unserved. In reality, if this price is not reached, or investors do not believe that it will be reached, due to regulatory or political intervention, or a failure to make the cash out rules perfectly cost reflective, then the capacity margins are likely to be worse than this. How much worse depends on the level that investors expect the price to rise to, and the level of new investment required to be incentivised through the market in order to meet security of supply.

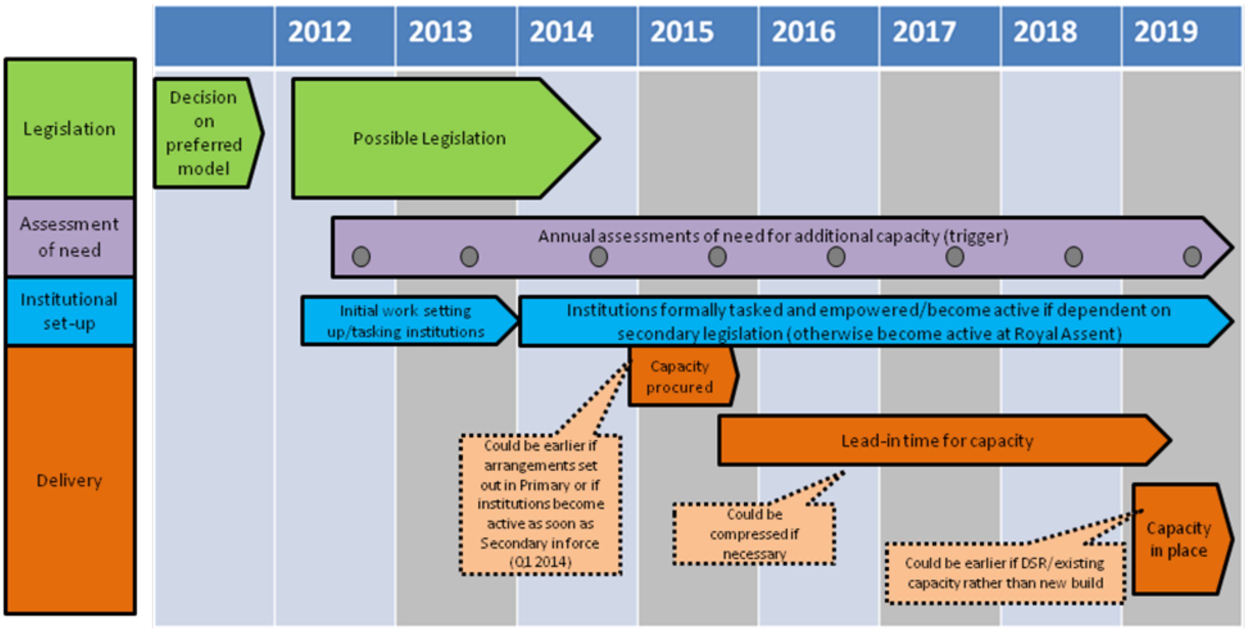
4.1.3 Timing

334. The modelling undertaken for this project indicates that any possible shortfall in capacity is likely to occur towards the end of the decade. The timing for the setting up and entry into

[48] Important to note that this modelling has relatively conservative assumptions around demand side response, assuming that it carries on as today, with around 1GW of energy intensive industries having flexible demand. To the extent that demand side response can be incentivised and increased, we would expect energy unserved to be reduced.

operation of a CM would need to be such as to provide certainty that any shortfall arising on such a timescale would be dealt with. Figure 13 sets out the initial view of when a CM could reasonably be introduced and possible milestones.

Figure 13: Indicative timetable for the introduction of a Capacity Mechanism.



4.2 Options for intervention

335. The original consultation document had a preferred option for a Capacity Mechanism of a tender for targeted resource. In recognition of consultation responses, we have both refined the detail of the original preferred option to seek to address the concerns raised and explored an alternative, market-wide model in more detail. We are seeking views in the consultation, set out in Annex C of the White Paper, on the detailed design of our approach for each:

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

337. • a market-wide mechanism in the form of a Capacity Market, in which all providers willing to offer capacity (whether in the form of generation or non-generation technologies and approaches such as storage or DSR) can sell that capacity; and the total volume of capacity required is purchased. There are several forms of Capacity Market, depending on the nature of the 'capacity' and how it is bought and sold. In particular, there are a number of ways to purchase capacity – including through a central auction or a supplier obligation. One form of a Capacity Market is a Reliability Market, where, given its innovative nature and potential benefits, we are keen to gain stakeholder feedback. To help inform this feedback, we have modelled a Reliability Market here. In addition, for simplicity, and to keep the analysis manageable, it has been necessary to focus the analysis in this Impact Assessment to the two forms of Capacity Mechanism mentioned. However, we recognise that there are other forms of market-wide mechanism, such as those which set price in order to incentivise sufficient volume (Capacity Payments), and these remain under consideration.

4.2.1 Option 1: targeted Capacity Mechanism: Strategic Reserve.

338. The lead option in the Consultation Document was a "tender for targeted resource." A number of mechanisms fit this general description, and we have narrowed the choice to a Strategic Reserve as the most appropriate for our market. A Strategic Reserve is an amount of generating capacity which is held outside of the normal market, as described below.

339. A central body decides on the level by which the market is expected to fall short of the total capacity required a few years ahead. An additional amount of capacity is then purchased through some competitive process. We expect that the reserve would include technologies other than generation technology such as demand side response and storage. The reserve thus purchased is removed entirely from the energy market except in predefined, exceptional circumstances. On one approach, those circumstances are when the market price for electricity exceeds a pre-determined threshold value, the "reserve despatch price"; When this happens, the reserve is offered into the market at that predetermined price.

340. There are additional design considerations, the main one being the price at which the reserve is despatched. A higher price interferes less with the existing market (and requires less adjustment to take account of this interference) but provides less mitigation of the incentives to exploit market power. In the limit, the highest feasible price for dispatching the Strategic Reserve would be at the value of lost load. The lowest feasible price would be at the long run marginal cost of the highest cost generator. In addition, the technical characteristics of the

reserve will need to be decided and the procurement process will have to be designed. The White Paper which this Impact Assessment accompanies contains a detailed consultation on the design of a Strategic Reserve.

4.2.2 Option 2: market-wide Capacity Mechanism: Reliability Market.

341. A central body forecasts peak demand for some years ahead. That total amount of capacity is purchased, in the form of "reliability contracts," from any generator willing to supply it including new entrants who are planning to build capacity. We expect that this capacity would include technologies other than generation capacity such as demand side response and storage.

342. A reliability contract is a financial instrument: The contract specifies a strike price, a capacity (in MW), and a contract duration; the holder of the contract (i.e. the counterparty to the capacity provider) is entitled to receive, on demand, the difference between the current spot price of electricity and the strike price, for the amount of capacity written in the contract[49].

343. They can be thought of as a "one-sided contract for difference." In effect, the generator exchanges an uncertain and volatile revenue stream (when the market price is high) for a more certain income (the value at which the contract is sold). Consumers are also hedged against price spikes, reducing their risk. To the extent that both parties prefer lower risk, this is a net gain.

344. A Reliability Market preserves the economic incentives to be available at times of system scarcity. The system is defined to be entering scarcity conditions when the price rises above the strike price of the contract. At this point, the generator is liable for the spot price in the amount of capacity it has sold. The easiest way for it to discharge this liability is to be selling into the market, for then it will be receiving the market price and can remit the difference to the holder of the obligation, retaining the strike price. Thus, the full market price is maintained as the appropriate incentive for generators to be available whilst the price consumers face is capped at the strike price.

345. There is a significant choice to be made as to who procures the capacity. Reliability contracts could be procured through a central auction (as in New England); bilaterally (by placing an obligation on suppliers); or, in principle, directly by consumers. These different choices are likely to have very different implications. The White Paper which this Impact Assessment accompanies contains a detailed consultation on the design of a Strategic Reserve.

4.3 Impacts of the policy

346. In assessing the costs and benefits of the two options presented above, it is necessary to use both quantitative and qualitative analysis. The quantitative assessment relies heavily on modelling from Redpoint's energy model and is broken down into:

- Net welfare including the administrative costs
- Distributional impacts (the impacts on consumers and producers of electricity)

347. In addition to the quantitative analysis, it is necessary to supplement this with a qualitative appraisal of the two Capacity Mechanisms. As the section which outlined the rationale for an

[49] In some versions, there is an additional penalty for not being available during the periods when the market price is higher than the strike price. There may be good reasons to consider this addition, but in this note we discuss only the "pure" form of reliability contracts

intervention set out, there are a number of market failures in the electricity market which will lead to sub-optimal investment decisions in generating capacity. It is not possible to quantify the scale of these market failures, so the analysis of whether the options can help to address them is necessarily qualitative. Nevertheless, this qualitative appraisal forms an important part of the assessment of the options. The qualitative costs and benefits (or alternatively pros and cons) of the various options can be grouped around the following headings.

- Security of supply
- Practicality and feasibility
- Durability
- Impacts on barriers to entry
- Impacts on the market
- Compatibility with other EMR options

4.3.1 Quantified Costs and Benefits

4.3.1.i Modelling Approach

348. The net welfare impacts and the distributional impacts have been derived from the Redpoint Energy model. Details of the Redpoint model and the modelling approaches are summarised in Annex E. For the purposes of the Capacity Mechanism modelling, Redpoint have simulated the effects of a market-wide Capacity Mechanism based on the use of reliability contracts and the Strategic Reserve on the basis of the System Operator (SO) tendering for capacity to meet a desired capacity margin. The assumed implementation date for CM measures is 2019, which is the first date that new capacity is forecast by the model to be required.

(a) Reliability Market

349. Both the contract allocation process (auction) and the effect on the wholesale market are modelled. The model of the auction process is a ‘stack’ of the capacity offered into the auction. The offer prices for each generator is calculated based on the required additional revenue to extend the plant lifetime or build a new plant. Demand Side Response is not modelled as being able to participate in the auction. DSR would have the potential to lower costs to consumers if it participated since provision of DSR resources through demand reduction/shifting usually has a lower associated cost than increasing (or building new) generation.

350. The key parameters for the Reliability Market option are:

- Security standard: defined as a minimum 10% de-rated capacity margin. The volume of contracts bought by the central buyer will be peak demand + 10%.
- Contract strike price: starting at around £200/MWh, which is just above the short run marginal cost of a gas turbine and escalating with gas & carbon prices
- Contract length: 1 year contracts for existing plant, and 10 year contracts for new plant.
- Open to all generators (but assume low-carbon generators bid at zero).

- All generators received the auction clearing price (except where explicitly stated below for new low-carbon generators).
- That the first auction would be held to cover the year 2019, the first year that new capacity was required.

(b) Strategic Reserve

351. The key parameters for the Strategic Reserve option are:

- Security standard: defined as a minimum 10% de-rated capacity margin.
- A central body forecasts the need for additional capacity accurately and tenders for some general capacity (that is met from existing coal and CCGT plant) and some responsive capacity that is provided by OCGTs. For some generators this would require a change of IED decision from Limited Lifetime Opt-out (LLO) to Transitional National Plan.
- The gap between the forecast de-rated capacity margin and the targeted 10% that develops in the early 2020s is assumed to be filled by a range of generation technologies.
- The tendered capacity mix is one of multiple combinations of new and existing plant which would fulfil the requirements.
- The role of new DSR is not modelled as being able to participate in the Strategic Reserve, but would have the potential to lower costs to consumers if it participated as has been shown by experience in the USA, for example.
- It is assumed tendered capacity does not affect the wholesale market or weaken investment signals for non-tendered capacity. It is therefore a form of last resort Strategic Reserve.

4.3.1.ii Caveats to the modelling

352. The costs and benefits of any Capacity Mechanism in practice will be to a large extent dependent on the design of that mechanism. In the time available, we have attempted to provide Redpoint Energy with the most sensible design for a Reliability Market as possible. However, the design of any mechanism is necessarily complex and as part of the implementation of the mechanism, will require careful thought. Therefore the numbers from the modelling are a best attempt to simulate the impacts of a Capacity Mechanism, but the practical details of implementation will doubtless have an impact on the final costs and benefits of a Capacity Mechanism.

353. There are a number of assumptions which are likely to mean that the quantified costs and benefits are likely to underestimate the benefits of a Capacity Mechanism. For example:

- The model has assumed a VoLL of £10,000/MWh. This figure is widely used internationally, including for example by the International Energy Agency (IEA)[50]. However, as mentioned before, VoLL is highly uncertain. This is towards the lower end of the range put forward by Oxera[51]. For the purposes of modelling, this means that prices may not rise as high as they would do in a shortage if VoLL were higher. All other things being equal, and ignoring the presence of missing money, higher prices would lead to increased incentives to invest. On the other hand, in the appraisal, a higher VOLL would mean that the benefits of increased security

[50] Security of Supply in Electricity Markets, IEA, 2002
[51] What is the optimal level of electricity supply security, (2005)

of supply would be greater. We have included a sensitivity around the VoLL used in the appraisal.

- The model does not capture market imperfections such as missing money, barriers to entry on the generation side and strategic pricing in energy markets. These imperfections would put a greater level of risk around the market not delivering timely investment and hence pose risks to security of supply. The relationship between EEU and the margin (as shown by Figure 11) has fair degree of dispersion and is both asymmetrical and complex.

354. On the other hand, there are some assumptions in the modelling which are likely to mean that the benefits could be overstated. For example:

- The model assumes that desired capacity is forecast accurately by a central body.
- The model assumes that capacity is delivered on time.
- As discussed previously, the modelling has not included demand side response being able to participate in the Capacity Mechanism. In addition, the analysis assumes only limited scope for demand side response to prices. In particular, they assume only that around 1GW of large scale commercial and industrial users are able to respond. This is a conservative assumption around the future of demand side response or participation. To the extent that the future roll out of smart meters, or any other innovations leads to greater participation of the demand side, this will tend to reduce the costs of insufficient capacity margins. In particular, it would tend to reduce the expected energy unserved shown in Figure 12. It may also reduce the security of supply benefits of a Capacity Mechanism.

4.3.1.iii Net Welfare

(a) Summary

355. The quantified results of modelling the two Capacity Mechanism options, a Strategic Reserve and a Reliability Market are presented for both decarbonisation options, both FiT CfDs and Premium FiTs. In terms of the overall effect on net welfare, Table 16 below summarises the options in the case that the low-carbon option is a FiT CfD .

356. Modelling indicates a net cost associated with either Capacity Mechanism. This is because, for modelling purposes, we have applied a security standard of 10% which is somewhat higher than the value of capacity implied by a VoLL of £10,000/MWh. By imposing a constraint that margins are increased to 10%, this will by definition lead to a negative NPV in the modelling. Note that the argument for a Capacity Mechanism rests on the fact that the theoretically perfect market (which is assumed in the modelling), does not exist in practice and just as importantly, investors do not have confidence that prices will be allowed to rise sufficiently high to stimulate that investment[52]. These market and regulatory failures are discussed in section 4.1 .

Table 16: NPV in FiT CfD scenario, NPV 2010-2030, £m (2009 real)

Option	SR	RM
Value of carbon saved	-30	273

[52] In any future modeling we will examine whether it is possible to reflect the impact of market failures on capacity margins and energy unserved.

Change in running costs for generation	-572	-941
Increase in capital costs of new plant	-459	-673
Less unserved energy (security of supply benefit)	418	444
Demand side response	0	59
Change in Net Welfare (NPV)	**-643**	**-837**

357. As can be seen at a net welfare level, there is little difference between the mechanisms as modelled. Around £200m spread over 20 years is a very small amount in the context of the electricity sector. To put the number into context, the present value of the fixed costs alone (i.e. not including the variable fuel and carbon costs) of keeping one 830MW CCGT power station operating over the same period is around £324m[53]. The main modelled difference between the runs is that a reliability contract leads to slightly more investment in CCGTs compared to a Strategic Reserve which uses more OCGT which have lower capital costs. Redpoint have argued that these differences are not significant and could be affected by marginal changes in assumptions. In theory, a Strategic Reserve and a Reliability Market could be designed to bring on the same additional capacity, be it OCGT, CCGT, or demand side response or any other technology. The important point to take from this analysis is that a Strategic Reserve with a central buyer, may make a different choice of capacity mix compared to a more market based mechanism. Which produces the more efficient outcome in practice will to a large extent depend on the detailed design features of the mechanism which are not considered here. Both options produce similar levels of security of supply as shown by the energy unserved benefits and as expected because the modelling assumes each mechanism brings de-rated margins up to the desired 10% level.

Table 17: NPV in Premium FiT scenario, NPV, 2010-2030, £m (2009 real)

Option	SR	RM
Value of carbon saved	0	-228
Change in running costs for generation	-597	-197
Increase in capital costs of new plant	-322	-80
Less unserved energy (security of supply benefit)	267	319
Demand side response	0	46
Change in Net Welfare (NPV)	**-652**	**-141**

358. Table 17 shows the net welfare impacts of a Capacity Mechanism in a scenario of Premium FiTs. In this scenario, a Reliability Market has a marginally more positive impact on net welfare compared to a Strategic Reserve. This is because, in the modelling, they lead to a different investment mix with lower capital and running costs.

359. While the overall net welfare figures are negative, it is worth bearing in mind the caveats to the modelling expressed earlier. These impact of market and regulatory failures are unquantified. A wider qualitative assessment of the costs and benefits of the different Capacity Mechanisms are presented in the section that follows on non quantified costs and benefits.

[53] Figure derived from Mott Macdonald report http://www.decc.gov.uk/assets/decc/statistics/projections/71-uk-electricity-generation-costs-update-.pdf. Fixed costs of nth of a kind 830MW CCGT plant = £26,000/MW/yr.

360. A final caveat is around the value of lost load. Table 16 and Table 17 are based on a value of lost load of around £10,000MWh. However estimates of VoLL are very uncertain and difficult to ascertain since they depend on many factors including customer type (household/industrial), time of day, time of year, duration and frequency. Hence there is no clear consensus in the current literature on the appropriate value of lost load (an aggregate measure of the costs of interruption). Some estimates have put it as high as £30,000MWh[54]. Even this higher figure only includes the direct costs of energy unserved and does not include any external social costs of energy unserved. Therefore if VoLL were assumed at this level, or higher to account for wider social benefits, then there would be an overall welfare gain from both of these options[55]. Table 18 illustrates the effect of using a VoLL of £30,000MWh; as can be seen, with a higher VoLL, net welfare is marginally positive in all scenarios.

Table 18: NPV with VoLL at £30k/MWh, NPV 2010-2030, £m (2009 real)

Option	SR	RM
Change in Net Welfare in FiT CfD scenario	**193**	**50**
Change in Net Welfare in Premium FiT scenario	**-118**	**497**

361. Similarly the modelling does not capture the benefits in terms of resource cost savings from new demand side resources (DSR) participating in the market under either a Reliability Market or the Strategic Reserve. Experience from the US[56] has shown that DSR can lead to major cost savings. For example in the forward capacity auctions in New England, DSR is directly attributed to reducing costs by as much as $280 million by reducing the price paid to all capacity resources in the market. Moreover in the PJM capacity auctions in May 2009 the participation of DSR meant that auction prices were $162/MW per day lower they would have been otherwise. Therefore to the extent that Capacity Mechanisms can incentivise more DSR to participate in the market then the greater the welfare benefits are likely to be. The relative strengths of the two Capacity Mechanisms in bringing on DSR is discussed qualitatively in paragraph 413.

4.3.1.iv Distributional impacts

362. Whilst the net welfare effects show there is only a marginal difference in the costs between the options, the analysis shows there is a difference between the distribution of these costs between consumers and producers. Table 19 below shows the distributional impact of the Capacity Mechanism in a FiT CfD scenario. As modelled, with a Reliability Market, there is a large reduction in wholesale electricity prices which more than offsets the additional low-carbon support and the additional capacity payments. The additional low-carbon support is simply a top up because there has been a reduction in wholesale electricity prices.

Table 19: Distributional analysis of options in FiT CfD scenario, NPV 2010-2030, £m (2009 real) [57]

Option	SR	RM

[54] What is the optimal level of electricity supply security, Oxera (2005)
[55] Note that the results presented in this table are based on a modelling assumption that prices only rise to VOLL which is fixed in the model at £10,000/MWh. If they were able to rise to £30,000/MWh, and investors could count on this, then we would expect to see higher capacity margins.
[56] The role of forward Capacity Markets in increasing demand side and other low carbon resources: experience and prospects, Meg Gottstein and Lisa Schwartz, RAP Policy Brief, May 2010
[57] For simplicity change in environmental taxes i.e. CCL are not shown in the distributional analysis as these are relatively small.

Change in wholesale price	-49	24,755
Change in low-carbon support	4	-7,854
Capacity payments	-1,183	-13,101
Unserved energy	418	444
Demand side response	0	59
Change in consumer surplus	**-810**	**4,302**
Change in wholesale price	49	-24,755
Change in low-carbon support*	-4	7,852
Capacity payments	1,183	13,101
Change in producer costs	-1,061	-1,298
Change in producer surplus	**166**	**-5,100**

363. If the low-carbon support option is Premium FiTs rather than FiT CfDs, then the modelled distributional impacts of the two Capacity Mechanisms are very different. Table 20 below shows the impact of a Capacity Mechanism in this scenario. It suggests that in a world of Premium FiTs, there is a transfer from consumers to producers as opposed to the opposite effect in a world of FiT CfDs.

Table 20: Distributional analysis of options in Premium FiTs scenario, NPV 2010-2030, £m (2009 real)

Option	**SR**	**RM**
Change in wholesale price	-88	17,154
Change in low-carbon support	7	-7,666
Capacity payments	-1,033	-16,799
Unserved energy	267	319
Demand side response	0	46
Change in consumer surplus	**-848**	**-6,947**
Change in wholesale price	88	-17,154
Change in low-carbon support*	-8	7,725
Capacity payments	1,033	16,799
Change in producer costs	-918	-507
Change in producer surplus	**196**	**6,864**

364. The differences between the two tables are for two main reasons. The first is that we do not have nearly as large a reduction in wholesale prices as a result of the Reliability Market in a Premium FiT world as opposed to a FiT CfD scenario. The reason for this is that in the modelling, wholesale prices are higher in a world of FiT CfDs. This is the result of scarce capacity. Figure 12 showed capacity margins under a FiT CfD and Premium FiT scenario with no Capacity Mechanism. As can be seen, in the FiT CfD world, margins are tighter. The new nuclear capacity which comes on earlier in the FiT CfD scenario leads to a lack of investment in flexible peaking plant and a tighter market. A tight market necessarily leads to large transfers from consumers to producers as they are able to extract scarcity rents. Hence the benefits to consumers of a RM in reducing prices is higher in a FiT CfD scenario as modelled.

365. The second reason for the large difference, and the reason why there is a net transfer from consumers to producers as a result of a Reliability Market in the Premium FiT scenario, is a result of how the auction clearing price is set in the Reliability Market. In the modelled Premium

FiT scenario, capacity margins are less tight in the middle part of the next decade compared to a FiT CfD scenario as shown in Figure 12. As a result, not a lot of new capacity is incentivised as part of the reliability contract. Instead, the auction clearing price in a number of years is set by loss making existing capacity (see annex E for a description of how the market price is set in the modelling). When this happens, the Reliability Market delivers transfers from consumers to producers, without the accompanying benefits of lower wholesale prices.

366. These two competing forces in the modelling drive the large distributional impacts of the Reliability Market. In reality it will be important to take these possible effects into account when designing a Reliability Market. The ability to protect consumers from scarcity rents associated with a tight market is a key potential benefit of a Capacity Mechanism which caps wholesale prices such as the Reliability Market. At the same time, if not designed carefully, then the Reliability Market could turn out to deliver rents to existing producers with little in the way of security of supply benefits. The point here is that whether a Reliability Market leads to transfers to consumers or from consumers depends on the extent to which it can mitigate scarcity rents in the wholesale market, while at the same time avoiding paying rents in the Capacity Market. In other words, the more that scarcity is thought to be a problem in the absence of a Capacity Mechanism, the more the consumer benefits from the introduction of a Reliability Market as opposed to a last resort Strategic Reserve.

367. Table 21 compares the results for the Reliability Market shown in Table 19 and Table 20 to a scenario in which low-carbon generators do not receive any capacity payments. As mentioned previously, the model assumes that low-carbon generators receive the auction clearing price in the market for reliability contracts. If plant eligible for FiT CfDs could not join the Reliability Market as discussed on section 4.3.2.vii , then, there would be greater benefits to consumers and lower benefits to producers as low-carbon generators would not receive windfalls. In fact, capacity payments for low-carbon plant in the FiT CfD and the Premium FiT scenarios are around £2.6bn and £2.2bn respectively. To help comparison, the results which have changed, where low carbon receives capacity payments are shown in brackets.

Table 21:Distributional analysis of a Reliability Market where low-carbon plant are not included in the market for reliability contracts, NPV 2010-2030, £m (2009 real)

Option	**FiT CfD**	**Premium FiT**
Change in wholesale price	24,755	17,154
Change in low-carbon support*	-7,854	-7,666
Capacity payments	-10,496 (-13,101)	-14,513 (-16,799)
Unserved energy	444	319
Demand side response	59	46
Change in consumer surplus	**6,907 (4,302)**	**-4,661 (-6,947)**
Change in wholesale price	-24,755	-17,154
Change in low-carbon support*	7,852	7,725
Capacity Payments	10,496 (13,101)	14,513 (16,799)
Change in Producer Costs	-1,298	-507
Change in producer surplus	**-7,705 (-5,100)**	**4,578 (6,864)**

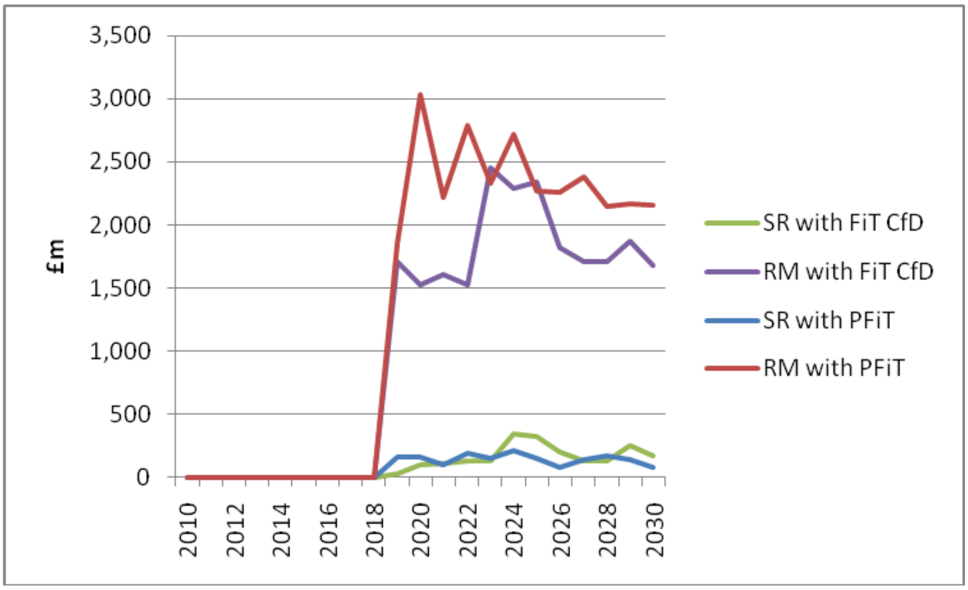
368. It is the case that much of the modelled difference between the targeted mechanism and the Reliability Market is the result of the way that the model simulates the mechanism design. Smart design of the mechanism should be able to reduce these failures. Table 21 shows that where market distortions and rent capture can be limited through design, there would be greater benefits to consumers through enhanced consumer surplus. The modelling demonstrates this clearly in this case, although the point could be extended more widely.

369. Previous analysis for the EMR consultation document also suggests that where a Strategic Reserve is designed such that plant in the reserve is despatched on the basis of its position in the merit order, as opposed to being used only as generation of last resort, this could result in further benefits to consumers as a result of reducing the opportunities for producers to make scarcity rents. In this alternative case, there could be lower wholesale prices as they would no longer spike up to £10,000/MWh (up to the value of VOLL) which has been assumed as possible in the modelling if there is insufficient supply to meet demand. If, for example, the Strategic Reserve capacity was priced into imbalance charges at £500/MWh, effectively putting a cap on prices at this level, then costs to consumers could on average be lower by about £1.3/MWh with a last resort Strategic Reserve. However, Redpoint state that it is difficult to draw strong conclusions whether a Strategic Reserve based on economic despatch could result in such savings to customers without a better understanding of how prices behave under times of system stress, and how the tendered capacity would be deployed and priced into the market.

4.3.1.v Cost of public support

370. The Capacity Mechanism will require a payment of funds to generators and these will need to be funded. There are a number of options through which this could be achieved and these are discussed in the package section. Should the Capacity Mechanism be classified as taxation then there will be an impact on the public finances. Figure 14 below shows the public support costs of the Capacity Mechanisms using results from the modelling. As modelled, a Reliability Market results in a greater level of public support that a Strategic Reserve. The reason for this result is that for a Reliability Market, the cost of public support is defined as the upfront capacity payment. No account is taken of the lower wholesale cost of electricity that results from placing what is in effect a cap on the electricity market. Indeed by raising the strike price of the reliability contract from that modelled, we would expect a lowering of the capacity payments (bidders in the Reliability Market would receive more from the wholesale market and less from the Capacity Market). For the Strategic Reserve, the cost of public support is simply the cost of the extra capacity, together with the fixed costs of the plant and the (very small) running costs when the market is short.

Figure 14: Costs of support for Capacity Mechanisms



Source: EMR Redpoint analyis

(a) Impact on consumer bills

371. Table 22 below shows the estimated impact on average annual domestic, non domestic and energy intensive users from the introduction of a Strategic Reserve and a Reliability Market in a scenario of a FiT CfD.

Table 22: Consumer bill impacts of Capacity Mechanisms with FiT CfD

Option	Average bill with FiT CfD	Change in average bill with Strategic Reserve	Change in average bill with a Reliability Market
Domestic (£)			
2011-2015	469	0%	0%
2016-2020	481	0%	1%
2021-2025	560	0%	-3%
2026-2030	622	0%	0%
Average (2010 – 2030)	531	0%	-1%
Non Domestic (£000)			
2011-2015	967	0%	0%
2016-2020	1,134	0%	1%
2021-2025	1,413	0%	-3%
2026-2030	1,417	0%	0%
Average (2010 – 2030)	1,218	0%	-1%
Energy Intensive Industry (£000)			
2011-2015	7,480	0%	0%
2016-2020	9,001	0%	1%
2021-2025	11,551	0%	-4%

2026-2030	11,688	0%	0%
Average	9,786	0%	-1%

372. Table 23 below shows the same customer bill impacts in a world of premium payments.

Table 23: Consumer bill impacts of Capacity Mechanisms with Premium FiT

Option	Average bill with PFiT	Change in average bill with Strategic Reserve	Change in average bill with a Reliability Market
Domestic (£)			
2011-2015	469	0%	0%
2016-2020	489	0%	2%
2021-2025	561	0%	0%
2026-2030	643	0%	2%
Average	538	0%	1%
Non Domestic (£000)			
2011-2015	968	0%	0%
2016-2020	1,157	0%	2%
2021-2025	1,416	0%	1%
2026-2030	1,472	0%	3%
Average	1,237	0%	1%
Energy Intensive Industry (£000)			
2011-2015	7,484	0%	0%
2016-2020	9,203	0%	2%
2021-2025	11,579	0%	1%
2026-2030	12,196	0%	3%
Average	9,963	0%	2%

373. As can be seen, the Strategic Reserve has a negligible impact on consumer bills. The Reliability Market on the other hand can see consumers either better off in the case of FiT CfDs, or worse off in the case of Premium FiTs. The explanation for this effect can be found in paragraph 366.

(b) Impacts on Business

374. Businesses will be affected in two ways by a Capacity Mechanism. The first is the direct costs associated with the Capacity Mechanism and the second is the administrative burden of participating in the auction.

375. The direct costs and benefits imposed by the mechanism are those that accrue to ordinary businesses which consume electricity on the one hand, and those that accrue to electricity generation companies on the other. The direct impact on businesses are assessed in the package section.

(c) Administrative costs on business

376. The administrative costs of a Reliability Market are the result of both of the institutional costs of administrating mechanisms on the one hand and the administrative costs on business as a result of the mechanism. As part of the Government's Better Regulation agenda, The UK

has adopted the Standard Cost Model (SCM) method of providing an indicative measurement of admin burdens, DECC is monitoring the impact of its regulations on business and taking initiatives to minimise the administrative burden they impose. An administrative burden is the cost to business of the administrative activities that it is required to conduct.

377. An estimate of the cost to business of a Capacity Mechanism is given by the following formula:

Activity Cost = Price X Quantity = (wage x time) X (population x frequency)

378. The time taken to complete an activity and the wage rate of the person undertaking the task are based on the figures for a normally efficient business, and are typically estimated by hiring consultants or via interviews with businesses. The population is given by the number of businesses affected; and the frequency is the number of times per year that business has to undertake the activity.

379. For a Strategic Reserve, it is not thought that there would be any administrative burden imposed on businesses, because it would be centrally organised. However, a Reliability Market would have an additional impact because there would be a new market for generating companies to participate in.

380. For a Reliability Market, the process in estimating the administrative burden is as detailed above. The estimated population is the number of parties that might bid into the auction. Our current best estimate of this is between 80 and 239[58]. It is expected that each company participating in the auction would require between one and two members of full time staff to prepare the companies' bid into the reliability auction.[59] The average cost of each member of staff is estimated to be around £50,000[60]. Therefore the administrative burden placed on business as a result of this mechanism is estimated to be between £400,000 and £2.4m per year with a total cost of £5.7m -£36m on a PV basis. Note that these are tentative estimates and as part of the consultation process, we would expect to get more robust estimates of these figures.

4.3.1.vi Institutional set-up and administration costs

381. The institutional or administrative costs of a Capacity Mechanism are inherently tied up with any wider institutional changes which take place as a result of EMR. This is assessed in section 4.2.4.ii

4.3.1.vii Air quality analysis

382. This is assessed as part of the package analysis

4.3.2 Non Monetised Costs and Benefits

383. As set out in paragraph 347, there are a number of costs and benefits of the options which it is not possible to quantify using the Redpoint model. This is partly because the model cannot capture all aspects of the electricity market e.g. it does not have a detailed representation of the balancing mechanism. Nevertheless, from a theoretical analysis, these non monetised

[58] Lower figure comes from 5.11 in DUKES and is the number of major power producers. The upper figure represents the current number of Balancing and Settlement Code parties.
[59] This would need to be consulted on either by hiring consultants, or by interviewing the relevant companies.
[60] This is the cost of a business consultant in BERR's guidance

impacts are thought to be significant and therefore it is important that the options are appraised qualitatively. The options are appraised under the following headings:

- Security of supply
- Practicality and feasibility
- Durability
- Impacts on barriers to entry
- Impacts on the market
  - Short-term market power
  - Demand side efficiency
  - Supply side efficiency
  - Impacts on the wholesale market
- Compatibility with the current market
- Compatibility with other elements of the EMR
- Impacts on small businesses

4.3.2.i Security of Supply

384. The fundamental purpose of a Capacity Mechanism is to ensure that the required capacity, including technologies such as Demand Side Response and storage is in fact created.

385. *Strategic Reserve*: First, a Strategic Reserve requires two forecasts, both of which are likely to be subject to uncertainty: one forecast of peak demand and one forecast of the capacity that would be brought forward by the market. The volume of reserve required is related to the difference between these.

386. Second, the capacity one expects to be displaced from the market by the Strategic Reserve must be estimated. The reserve despatch price will be effectively a cap on the market price, resulting in lost remuneration for all generators during the times when the price would have risen above this level. The extent to which this takes place depends on the price at which it is set. The higher the price, the less capacity will be displaced from the market. In the limit, if the reserve is priced in at the average value of lost load, then no capacity should be displaced from the market. Thus, the reserve will displace some generation and the amount of displacement must be added to the reserve; this calculation is likely to be difficult and subject to uncertainty.

387. Third, there is the likely impact on investment cycles. In principle, the second problem above could be mitigated by setting the price at which reserve is despatched to be closer to VoLL. Assuming that prices would not have risen higher than this in the event of a shortage, then no capacity will be displaced. However, the worry may be that the electricity market is subject to boom-and-bust cycles, which seems a strong possibility given the high capital costs and long lead times involved, and this choice would not mitigate those cycles. A lower despatch price would provide more stable price signals to the wider market since, under this choice, prices would rise to the despatch price more frequently than otherwise. Note that setting the price cap equal to VoLL has the perhaps undesirable consequence that the reserve would not

obviously provide economic benefit—at this price, consumers are, by definition, indifferent between disconnection and paying the higher price.

388. In principle, the Strategic Reserve should only enter the market when all other capacity has been exhausted – otherwise, it is displacing capacity which would otherwise have been in the market. Stakeholders' concern is that, if this were the case, Ministers would come under heavy pressure to reduce the price at which the reserve entered the market during extended periods of high prices. Importantly, the mere perception of this risk will tend to disincentivise investment, leading to under-investment and the need to procure ever more reserve – the "slippery slope". As far as possible, the design of the mechanism would need to mitigate this threat.

389. *Reliability Market*: In a Reliability Market, all the required capacity is purchased, only a forecast of peak demand is required. Because of the strong incentives to generators who have sold these contracts to be available at times of system tightness under this option, a Reliability Market is the more likely to deliver the desired level of security of supply. A Reliability Market ensure that generators still face the full market price at the margin and their incentives to maximise production therefore increases with increasing market price rather than simply being capped. If the reform of cash out results in the cost of load-shedding entering the balancing mechanism, then these incentives will be particularly acute should load-shedding occur.

4.3.2.ii Practicality and feasibility

390. In order to deliver the benefits of increased security of supply, any intervention needs to be able to be implemented in practice. This section examines these aspects of the alternative options.

391. *Strategic Reserve*: This option could feasibly be incorporated within the current market structure. A mandated body could purchase the required reserve capacity, perhaps through a commercial tendering process similar to the way National Grid currently procure short-term operating reserve (STOR). It is reasonably clear how we should despatch this reserve; and, if the reserve is despatched appropriately, the adverse impact of market distortions could in principle be kept to a minimum.

392. Nevertheless, there are some drawbacks to the Strategic Reserve option. Regarding cost: There is obviously uncertainty about the level of capacity that the market would have brought forward in the absence of a reserve and the body charged with deciding the level of reserve to acquire. There is a risk that the body could act cautiously and over-procure. In addition, because of the difficulty in getting the incentives right, the body charged with procuring this capacity may not be able to keep the costs of the reserve as low as market participants would have done if the capacity was procured through the market.

393. Regarding effectiveness: In order to minimise market distortion, the reserve must only enter the market at the (high) price set in its operational rules. The revenues earned by commercial generators during these times are part of those generators' incentives to invest. However, it is argued—and we find it very plausible—that during times of sustained scarcity (such as a multi-day period of low wind) the political ability to sustain high prices will come under increasing attack. This would be mitigated by trying to create institutional "distance" between the despatch of the reserve and political decision-makers. There may well be an understandable view that generators are profiting at consumers' expense—and consumers will note that the reserve is being held back. In summary, it is possible that the reserve will be used unnecessarily,

or despatched at a lower price than necessary. Possible ways of mitigating this are being consulted on as part of the White Paper.

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

395. There is a also a concern that, at least initially, a full market would result in unnecessary payments (“windfalls”) to existing generators who have already made their investment decisions and do not require further incentives. (As noted elsewhere, at least some payment to existing generators is “fair,” because the cost is recovered through the option payment.) The obvious solution, removing existing capacity from the capacity requirement and not allowing existing generators to participate, fails to allow plant that would have closed to participate, and this plant may well be the cheapest way of continuing to provide reliability. Nonetheless, systems that have Capacity Markets have typically attempted to distinguish between existing and new capacity.

4.3.2.iii Durability

396. GB’s electricity generation system is characterised, on the supply side, by flexible coal and gas thermal generation and, on the demand side, by inflexible consumption. This balance will change dramatically over the next few decades to one of more inflexible and intermittent generation on the supply side but also more responsive demand side (including storage). We consider it an essential feature of the costs and benefits of a Capacity Mechanism that it be robust to these changes; that it not inhibit the needed changes; and that, if and when it is no longer needed, it can be easily removed or evolved into something more appropriate.

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

398. *Reliability Market*: Under a Reliability Market, providers of DSR could also participate, in a similar way, by selling reliability contracts where they met the necessary characteristics. In addition, reliability contracts are plausibly more compatible with a future market which has a more liquid and responsive demand side. Since they are a market-wide approach, consumers, potentially via suppliers, could be more engaged in the decision about the minimum level of reliable supply they require based on the cost to them of differing levels of reliability. Smart Meters could help to enable such a transition.

4.3.2.iv Impacts on barriers to entry

399. Any intervention which can reduce barriers to entry and help to make the electricity market more competitive will improve the allocative and productive efficiency of the market. The

primary channel through which any intervention is likely to have an impact on barriers to entry is through liquidity of the market.

400. *Strategic Reserve*: The impact of a Strategic Reserve on liquidity is uncertain. To the extent that it replaces some capacity from the energy-only market, this will remove some liquidity from that market. However, it also provides an alternative route to the market for flexible/peaking capacity away from the current six vertically integrated companies which dominate the market. The effect on removing barriers to entry is therefore not likely to be significant and it is not clear whether the impact would be positive or negative.

401. *Reliability Market*: A market for reliability could in principle be helpful to new generators, again if contracted sufficiently far in advance to allow new build and if the contracts are of sufficient duration to provide certainty (this is clearly a desirable design feature). These new entrants would face less volatile revenues on which to base their investment decision than under the current market, and the payment for the option contract would result in a lower cost of capital. One downside might be the generator's risk of not being able to make the option payments when called (for example, if the generator was offline) and the consequent counter-party risk faced by suppliers; this may act against the ability of small generators to offer contracts for the full amount of their reliable capacity.

402. On the retail side, if the reliability contracts were procured by suppliers, then suppliers would face the additional costs of procurement. However, their costs in the energy market would be hedged and so they would face lower costs should they be short and therefore lower risks. The balance of this argument is not clear, nor whether it would differentially affect small, independent suppliers.

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

4.3.2.v Impacts on the market

404. Any intervention is likely to have an impact on the operation of the both the supply and the demand side of the electricity market. These impacts will have economic efficiency implications which are assessed below.

(a) Short-term market power

405. The energy-only market as it currently stands relies on flexible generating plant using "scarcity rents" at times of system tightness to cover their fixed costs. In an imperfectly competitive market, a generator may find it in its interests to withhold some of its capacity in order to drive up the price. Therefore, any unusually high prices are likely to attract the interest of the regulator, who could in theory impose a price cap. A price cap reduces the ability of generators to use any market power in this way since, once the price has reached the cap, further withholding is of no benefit.

406. However, high prices are also the signals produced by a well-functioning market in times when supply is tight. It is these signals that incentivise the construction of new capacity. If high prices are muted unnecessarily then the required investment will not be forthcoming. And, unfortunately, it is precisely at times of tightness of the market that the incentives to withhold become stronger, especially in the electricity market with an inelastic elasticity of demand. It is likely that the regulator will find it very difficult to distinguish between the abuse of market power and the appropriate capture of so-called "scarcity rents."

407. *Strategic Reserve:* A Strategic Reserve introduces a price cap into the market (at least one with a price cap which is lower than the Value of Lost Load). This will reduce the incentive for generators to withhold energy and reduce the incentives to withhold energy compared to an energy-only market.

408. *Reliability Market:* Reliability contracts also introduce an effective price cap into the market, although as noted earlier, at the margin, generators still face the full market price at times of system scarcity.

409. We might also be concerned about the potential for exploitation of market power in the Capacity Market, whether in the tender for Strategic Reserve or in the Reliability Market. On the face of it, a reserve market is less susceptible to this kind of manipulation, since only an incremental amount of capacity is being acquired. (Although the purchaser would still need to be aware of the incentives for large generators to suggest that mothballed plant would otherwise have to close—with a concomitant negative impact on security of supply—in order to receive a capacity payment for that plant, even if they would otherwise have kept it open.)

410. A Reliability Market would need to be carefully designed to avoid being susceptible to exploitation. For example, a central determination of capacity could lead to an inelastic demand for capacity, and the market would then exhibit the same pathologies as the current, energy-only market.

411. In principle, the ways in which market power is mitigated are well known (at least, after well-known failures to implement these ideas in early US designs): The demand schedule (which may be centrally determined) should be made elastic; capacity should be procured far enough in advance to allow new entrants a chance to bid in; and demand-side participation should be encouraged to increase competition. The US Capacity Markets now employ some combination of these principles. Nonetheless, their early experience would lead one to be careful in the design.

412. Additionally, a Reliability Market would be innovative and its design may offer unforeseen loopholes to allow participants to "game" the system. Again, proper design would reduce the risk; but we imagine this risk must be higher in the full market approach.

(b) Demand Side Efficiency

413. As discussed earlier, it is inelasticity of demand that, in the electricity market, aggravates the problems of market imperfections. Were there to be demand-side participation in the market, a slight under- or over-investment in capacity would not have such asymmetric effects.

414. In addition, work undertaken by DECC on the future of the electricity system (such as the 2050 Pathways project) suggests strongly that demand-side response will be a significant component of the ability of the system to support large amounts of intermittent generation, such as wind. In the long-run the roll-out of smart meters is intended to give consumers the

ability to see and respond to short-term fluctuations in the balance between supply and demand. These fluctuations might be expected to become more volatile given the potential reforms

415. For these reasons, it is of importance whether a given Capacity Mechanism will tend to support or postpone the introduction of full demand-side participation.

416. *Strategic Reserve:* A reserve market could straightforwardly include demand-side response in the form of time-limited reduction from firm demand, as is done to a limited extent in the existing STOR operated by National Grid. This kind of product is typically offered by large industrial users but perhaps could also be offered by smaller consumers who engage through third parties known as aggregators. The key requirement of demand able to offer this service is that its unrestricted demand must be objectively measurable, so that the reduction can be called upon when needed.

417. A Strategic Reserve, while allowing demand-side response to play a part, does not appear to be supportive of the introduction of full demand-side participation. Since prices would be capped at the reserve despatch price, the incentive to reduce demand at peak times would be muted. Indeed, by providing a central guarantee of system security, and likely a conservative one, the reserve may discourage demand-side participation (which is likely to be inconvenient for consumers, especially in the early stages).

418. It may be that a Strategic Reserve could be adapted to provide somewhat better incentives, by allocating the cost of the reserve to suppliers based on an ex post determination of each supplier's contribution to peak demand.

419. *Reliability Market*: Evidence from US Capacity Markets suggests that this kind of demand response can successfully be offered into Reliability Markets as well, serving to reduce the overall cost of achieving security of supply, so in this regard there is no distinction between the two options. However, reductions from firm demand are not the same as full demand-side participation. In principle, an individual domestic consumer could be responsive to closer-to-real-time prices—and may well need to be—but would struggle to offer reductions "on demand" since they do not have a firm demand from which to promise a reduction.

420. In this regard, however, there is reason to believe that a Reliability Market with a supplier obligation may have a significant advantage. If there were an obligation on suppliers to contract for the capacity required by their customers, it would be in their commercial interest to reduce that obligation. They could do so by providing their customers with innovative tariffs or control systems that enabled and incentivised their customers to limit their peak demand. (Such schemes would presumably require smart meters.) Whatever central authority determines the suppliers' obligations would need to be able to take into account these schemes and assess their impact when doing so. Assuming this could be done, a supplier capacity obligation of this form would make it commercially advantageous for suppliers to help their customers participate in demand-side response.

421. There is an even more desirable possibility. It may be possible for this approach to evolve into one in which consumers decide for themselves how much firm capacity they require and contract themselves for this capacity (although presumably through a third party who may be a supplier or an aggregator). In principle, their exposure to market prices would then be capped, so long as their individual demand at times of system scarcity was less than their purchased capacity. If this could be done, there would no longer be a need for a central body to determine

the required level of capacity; instead, consumers would decide for themselves, as in any other market. It is not yet clear whether this approach can be implemented in our market, and in any case it would need each participating consumer to have a smart meter, but the potential benefits seem sufficiently great that it is an advantage of a Reliability Market, that they are a step in this direction.

422. The costs of centrally procured reliability contracts could, like the Strategic Reserve, also be allocated according to suppliers contribution to peak demand with the added benefit of providing the supplier with a price hedge (only) up to their contracted demand and full market pricing above this. In any case, it would be important to design the cost allocation methodology of any central mechanism carefully to ensure that benefits are maximised.

(c) Supply side efficiency

423. Just as one of the original goals of British Electricity Trading and Transmission Arrangements (BETTA) was to provide the correct incentives to market participants to despatch their generators efficiently, we assume a requirement on any Capacity Mechanism be that it provide the required capacity efficiently. To address this question, we consider two questions: (1) To what extent must the parameters of the market be determined centrally? (2) Does the mechanism provide the appropriate incentives for generation to be available when needed?

424. In the current energy-only market the ability to sell energy at the market price is the incentive to be available in times of scarcity. We have noted elsewhere that these incentives can become counter-productive if generators find it profitable to withhold.

425. *Strategic Reserve:* A Strategic Reserve whose reserve despatch price is low enough can reduce these withholding incentives by imposing a de facto cap on the market price. However, by doing so, it also reduces the incentive to be available that would have been induced by the high market price.

426. *Reliability Market:* In this regard, a Reliability Market is much better. Although there is an effective price cap, reducing the withholding incentives in the same was as just described, generators' total profit is still determined by the market price. Hence their incentives are not reduced, compared to the energy-only market.

(d) Impact on the wholesale market

427. *Strategic Reserve*: The Strategic Reserve operates "outside" the wholesale market (or option will be designed to ensure this) so interactions are expected to be limited. However as mentioned earlier to the extent that it introduces a price cap into the market then this would have an impact. In addition there could also be effects on market liquidity from any changes to the route to market for peaking plant that may arise, but the overall effect on liquidity is ambiguous and likely to be limited.

428. *Reliability Market: U*nder the Reliability Market proposals, generators will continue to need to sell their output into the market either via contractual offtake arrangements or through trading (or imbalance). But patterns of trading activity are likely to change as a result of the proposals.

429. With reliability contracts, holders of contracts are liable to difference payments whether or not they actually generate. This creates an incentive to trade for the reliability contract volume. This suggests that contract holders will seek to lock in volume on the forward markets.

However, this does present a basis risk linked to deviations between the forward trade price and the day-ahead reference price used to determine difference payments, which does create a bias towards trading in the reference market. This basis risk will be greater the lower the reliability contract strike price (as this increases the probability of having to make a difference payment), and vice versa. If the strike price is set relatively high, then forward trading before the reference market holds less basis risk, whilst also reducing volume risk. If, however, the strike price is set relatively low, then forward trading to reduce volume risk holds a greater basis risk. Arguably, in this case, trading activity would remain within the forward markets principally (rather than the reference market) in order to reduce volume uncertainty, but generators would seek to include a premium within the price to cover the potential basis risk exposure. Trading, however, will balance the volume and price risk elements, with activity spread between the markets in a manner considered to deliver an appropriate risk/reward balance. However, at this stage, it appears unlikely that the reliability contract will transfer significant volumes from the forward markets to the reference market (although this is dependent upon the level at which the strike price is set) and so the overall effect on liquidity is ambiguous.

4.3.2.vi Compatible with our market

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

431. *Strategic Reserve*: A Strategic Reserve does not appear to be affected by either the bilateral nature of the current market or the fact of vertical integration.

432. *Reliability Market*: Whether the contracts have been procured centrally, or through obligations, reliability contracts have typically been designed for systems with a single, close-to-real-time physical market (such as the Pool) in markets with separation of generators and retailers. To work in our market, they would need to be adapted. A number of academics, including those involved in actual market designs, have made proposals as to how they could be adapted. For example, the power sold forward by the generator through bilateral contracts could be deducted from their obligation under the reliability contract. Alternatively, under a supplier obligation, the option could be a physical option, where the generator is responsible for selling the energy through a standard bilateral market whenever the supplier calls the option. The costs and benefits of the alternative approaches would need to be appraised as part of the implementation of any mechanism. The fact that our market is strongly vertically integrated is also a challenge for a Reliability Market. If the two parties to a reliability contract are one company, then the option payment would simply be a transfer of money within that company, and it is not clear what the incentive would be. One option that has been proposed is to allow energy companies to rate the availability of their own generation; this amount would be deducted from their obligation on the supply side but they would be made liable for this amount being available—for example, through the payment of the market price less the strike price back to consumers.

433. The fact that our market is strongly vertically integrated is also a challenge for a Reliability Market. If the two parties to a reliability contract are one company, then the option payment would simply be a transfer of money within that company, and it is not clear what the incentive would be. One option that has been proposed is to allow energy companies to rate the

availability of their own generation; this amount would be deducted from their obligation on the supply side but they would be made liable for this amount being available—for example, through the payment of the market price less the strike price back to consumers.

434. In summary, a Strategic Reserve would not be affected by the presence of forward contracting and vertical integration; whereas reliability would need to be adapted. Again, we have no reason to believe that the adaptation could not be done (and proposals have been made) but the system has not been implemented in a market like ours and would therefore be innovative.

4.3.2.vii Compatibility with other elements of the EMR package

435. A major component of the EMR package is support for low-carbon generation through Feed-in Tariffs with Contracts for Difference (FiT CfD).[61] There may be interactions with the proposed Capacity Mechanism given that both policy instruments affect the amount of capacity that will be brought forward.

436. Strategic Reserve: The Strategic Reserve operates “outside” the market and it is assumed that, as participants in the reserve will likely be fossil-fired peaking plant, recipients of FiT CfD will not be directly affected.

437. Reliability Market: There could be interactions between low-carbon support and a Reliability Market. For example, consider the interaction between a Reliability Market and FiT CfDs for nuclear plant. We expect that nuclear, as a baseload plant, may receive a FiT CfD that uses the year-ahead forward price as the reference price. Under this FiT CfD the generator will be exposed to the short-term price and could in principle sell a reliability contract. However, part of the remuneration the generator receives from this reliability contract is required to provide compensation for lower wholesale prices and, since the FiT CfD already does this, there is a risk of overpayment.

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

439. Clearly, overpaying for capacity through a Capacity Mechanism, which has already been compensated through a CfD should be avoided, and it is possible to remove these interactions by prohibiting generation that is in receipt of a FiT CfD from participating in the Reliability Market. However, this raises additional concerns: for example, we would need to forecast the amount and reliability of FiT CfD -supported generation we expect to come forward.

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

[61] See Section 3 of this paper.

4.3.2.viii Impact on small firms

441. In terms of additional regulatory or administrative burdens, Capacity Mechanism will impact electricity generators in the sector, however these will be classed as large businesses, so no impact on small firms or micro-business are expected in this regard.

442. The Capacity Mechanism however although will impact on large businesses, the option could reduce barriers to new demand side providers, in this regard it could assist any new entrant small businesses wishing to participate in the market.

4.3.2.ix A summary of the qualitative analysis

443. This section provides a summary of the key trade-offs and relative assessment of the Strategic Reserve and Reliability Market form of a Capacity Market for comparative purposes.

444. The key trade-offs are:

- A **Strategic Reserve** has a well understood design, has been implemented in several markets, and could straightforwardly be implemented in GB. From a practical perspective, the mechanism scores highly. However, this model may be less effective in providing the desired level of security because it is likely to be difficult to design without distorting incentives in the electricity market. It may be less effective in incentivising the wider use of non-generation approaches such as demand side participation compared to a market-wide solution and it may be less compatible with increasing inter-system trade. It would also be difficult for this mechanism to be designed to help mitigate the effects of short-term market power without also having an impact on security of supply.

- The **Reliability Market** form of a Capacity Market is likely to achieve the required security of supply, is potentially more compatible with a longer-term move to a more responsive demand side, mitigates exploitation of market power in the energy market, and is efficient. It also has potential to more strongly incentivise non-generation responses to system adequacy issues such as DSR. However, it would be likely to be a larger intervention in our current market, and would be likely to present design challenges. It would need further development and stakeholder input before it could be ensured to work. It also introduces interactions with the FiT CfD, which are likely to make designing the Reliability Market more difficult.

Section 5 The Policy Package

445. This section considers the impact of the policies for reform when combining the policies into packages for reform. As previously mentioned, it has not been possible to present all the possible combinations of policies described in earlier sections for this assessment. Therefore, this section assesses four EMR packages against an updated baseline which includes the Carbon Price Floor policy as announced at Budget 2011 and existing policies such as the Renewables Obligation. Further details on the updated assumptions on the baseline and package modelling are described in Annex E. The four packages considered in this section are:

- Package 1: Contracts for Difference (FiT CfD) , Strategic Reserve (SR), EPS
- Package 2: Contracts for Difference, a Reliability Market, EPS
- Package 3: Premium Feed-in Tariff (PFiT), Strategic Reserve, EPS
- Package 4: Premium Feed-in-Tariff, a Reliability Market , EPS

446. All these packages also include the Emissions Performance Standard (EPS). The EPS has been evaluated in a separate Impact Assessment as the EPS policy options for the design and level at which the EPS should be introduced (as presented in the EMR White Paper) will not be binding on the low-carbon incentives or security of supply options assessed here.

447. This package analysis will firstly consider modelling results on the decarbonisation trajectory and security of supply implications of the four packages, before assessing the packages' impact on net welfare and the distributional impacts within the overall impact. Related to this, the section also includes an assessment of the impacts of packages on electricity bills and fuel poverty.

5.1 Cost-benefit analysis

5.1.1 Net present value of options

448. This section presents analysis of the options for reform in terms of their impact on net welfare, as well as distributional analysis of how the net impact on welfare is divided between impact on consumer and producer surplus. The latter discussion includes an assessment of how transfers between producers and consumers vary between the options.

5.1.1.i Impact on net welfare

449. Improvements in input assumptions since the publication of the EMR consultation stage IA in December 2010 and the announcement of the Carbon Price Floor, now considered to be a baseline policy, has led to the EMR packages now showing a *gain* in net welfare in all packages, compared to the updated baseline (more details are provided in Annex D). As the modelling is sensitive to changes in input assumptions, the interpretation of absolute figures of this quantitative modelling should be done with care and the results read as illustrative only.

450. The impact on net welfare of the EMR policies are due to the packages' impact on investment and generation decisions in the electricity market. EMR proposals incentivise investment in low-carbon plant. Investment in low-carbon plant typically leads to relatively higher capital costs and lower generation costs compared to a scenario with a higher share of fossil fuel fired generation plant. This is because low-carbon plant have higher up-front

capital/construction costs (but lower generation costs) than conventional fossil fuel generation. There are also obviously savings in carbon costs in a low-carbon electricity system.

451. Overall, the analysis shows that even though the packages are likely to lead to relatively higher capital costs, this increased cost will likely be offset by a reduction in generation costs and carbon costs, which means that there is a net benefit of the packages for reform.

452. Table 24 below shows the impact of the four packages on net welfare relative to the updated baseline up to 2030 under central fossil fuel price assumptions.

Table 24: Change in net welfare relative to the updated baseline, NPV 2010-2030, £m (2009 real)

£m *Relative to updated baseline(incl. CPF)*	**FiT CfD - SR** (EPS, CPF)	**FiT CfD - RM** (EPS, CPF)	**Premium FiT - SR** (EPS, CPF)	**Premium FiT - RM** (EPS, CPF)
Carbon costs	8,860	9,160	6,240	6,180
Generation costs	16,230	15,870	11,460	11,890
Capital costs	-16,070	-16,290	-10,650	-10,360
Unserved energy	120	150	120	130
Demand side response	-40	20	-30	20
Change in Net Welfare	**9,100**	**8,910**	**7,150**	**7,850**

453. Compared to the baseline, there is an overall positive net benefit from the introduction of both FiT CfD packages, as well as Premium FiT packages, albeit the latter to a lower extent. The modelling suggests that the highest gain in net welfare, compared to the updated baseline, is in the FiT CfD package with a Strategic Reserve type of Capacity Mechanism (£9.1bn NPV).

454. The change in welfare relative to the updated baseline in the packages to society as a whole can be broken down into effects on:

- construction costs
- generation costs
- carbon costs
- unserved energy and demand side response

455. A positive number represents a gain in net welfare to the economy. These four components are discussed in turn below.

456. The differences between the impact on net welfare between the packages above are driven by the different profile of generation technology mixes which leads to different decarbonisation trajectories. Differences in new build between the packages are shown in Figure 15 below and discussed in more detail in the following sections.

457. It is important to note that differences in the generation mix and the decarbonisation trajectories lead to differences in capital, generation and carbon costs between the packages. However, these differences are not a direct consequence of the instrument chosen beyond the

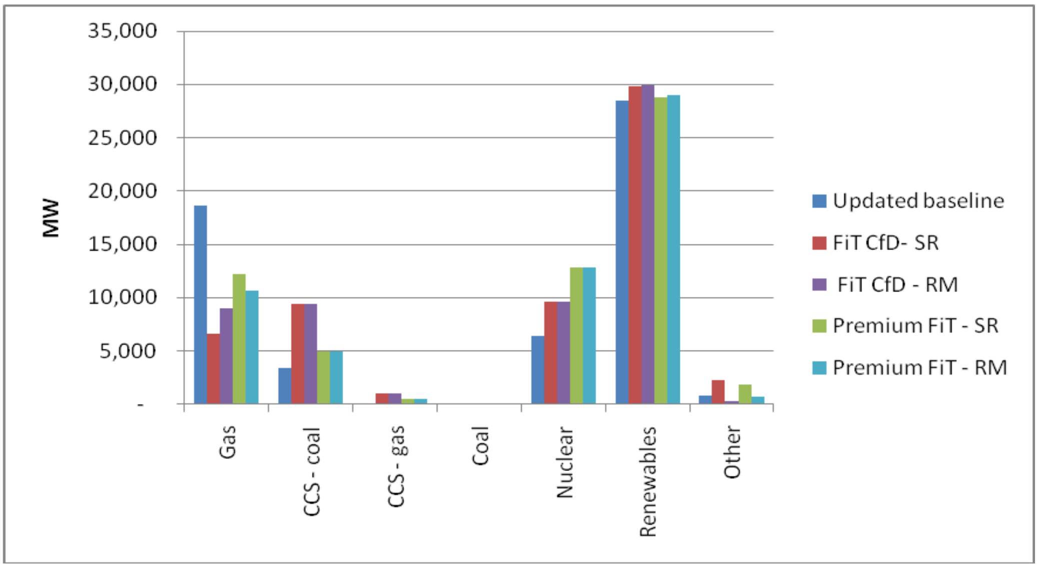
differences in the cost of capital assumed between a Premium FiT and a FiT CfD (see paragraph 461 for further discussion) and will in reality depend on the level at which incentives are set for different technologies. Therefore, the following welfare and surplus figures should be read as illustrative only, and the focus should be on interpreting the relative attractiveness of the packages, not on absolute figures.

(a) Construction costs

458. In general, policies to incentivise low-carbon plant typically lead to higher capital costs (and lower generation costs) in comparison to a scenario with mainly fossil fuel generation plant. This is because low-carbon plant have higher up-front capital costs (but lower generation costs) than conventional fossil fuel generation.

459. As shown in Figure 15 below, there is significantly more new build of high capital cost plant in the four EMR packages than in the updated baseline, which has predominantly new gas plant build.

Figure 15: Cumulative new build in the updated baseline and EMR packages to 2030.



Source: EMR Redpoint modelling

460. The difference in new build profiles between the packages in the modelling is due to differences in the instruments' impact on the cost of capital of technologies, and the level at which support is set. Therefore, the cost of capital assumptions indirectly affects the total costs and benefits because of the type of new plant it incentivises, and directly impacts on the capital costs of that plant.

461. The amount of new high capital cost plant build is greater in the FiT CfD packages than in the Premium FiT packages. If the financing costs in the Premium FiT-SR package were applied to the build profile of the FiT CfD - SR package, overall the FiT CfD -SR package would be approximately £2.5bn NPV more costly. This would imply that the NPV net welfare of the FiT CfD -SR relative to the updated baseline would be reduced to £6.6bn (relative to the updated Baseline). This shows the cost benefit of lower hurdle rates under a FiT CfD package: the same generation mix would cost £2.5bn less to build under a FiT CfD than a PFiT policy to incentivise low-carbon investment.

(b) Generation costs

462. As mentioned above, the lower-carbon generation mix brought forward under the policies leads to savings in generation costs relative to the updated baseline which has decarbonised to a lesser extent.

463. Generation costs are lower in the packages than in the baseline as a result of decarbonisation of the system. This is due to increased generation from plant with lower Short Run Marginal Cost (SRMC) on the system which replaces output from conventional gas plant. For illustration, Figure 28 below shows generation output in 2030 by technology, although the share of electricity generation output by technology varies by year.

464. Generation costs in this assessment refer to the change in the costs of generating electricity, including changes in fuel costs, variable and fixed operating costs and system balancing costs. It excludes changes in the costs of carbon which are captured by 'carbon costs' as discussed below. A positive number represents a decrease in generation costs relative to the updated baseline.

(c) Carbon costs

465. The savings in carbon costs too are a result of the more rapid decarbonisation under the four packages compared to the baseline, as shown in Figure 25 on page 124. Savings in carbon costs represents the change in value of carbon dioxide emissions as measured using the cost of EU Allowances. A positive number represents a decrease in carbon dioxide emissions, and therefore a saving in EU ETS allowance costs to the GB power sector, relative to the updated baseline.

(d) Unserved energy and demand side response

466. The impact of the options on unserved energy and demand side response is similar across the packages and small and therefore not considered in detail. The former represents the change in costs of expected energy unserved, and a negative number implies an increase in the cost of unserved energy. The latter represents the change in the use of short-term demand side response, where a reduction in demand in response to high prices represents a loss of consumer welfare[62].

5.2 Distributional analysis

5.2.1 Distributional implications of NPVs

467. This section looks at how the impact on net welfare for the economy as a whole is distributed between different segments of the society, namely between consumers and producers of electricity. The assessment of the distributional impact highlights the direction and nature of transfers between these.

468. **Consumer surplus** is a measure of welfare to consumers, and is a combination of the changes in costs facing the consumer (wholesale electricity costs, low-carbon payments and capacity payments) as a result of policies for reform.

[62] The cost benefit analysis does not consider the long-term price elasticity of demand.

469. **Producer surplus** is a measure of the change in profitability of the generation sector, measured as the change in the difference between the producers' revenues (electricity sales, low-carbon support and capacity payments) and producer costs.

470. Table 25 below shows the breakdown of the total net welfare impact, relative to the updated baseline, into consumer and producer surplus under central fossil fuel prices. A positive number represent an increase in surplus or a decrease in costs, relative to the updated baseline.

Table 25: Consumer and Producer surplus under central assumptions, NPV 2010-2030 £m (2009 real)

£m *Relative to updated baseline (incl. CPF)*		**FiT CfD - SR** EPS, CPF	**FiT CfD - RM** EPS, CPF	**Premium FiT - SR** EPS, CPF	**Premium FiT - RM** EPS, CPF
Consumer Surplus	Wholesale price	-3,930	20,880	-3,140	12,070
	Low-carbon payments	11,790	3,930	2,400	-4,980
	Capacity Payments	-1,180	-13,100	-1,030	-16,800
	Change in consumer surplus	**6,760**	**11,870**	**-1,680**	**-9,570**
Producer Surplus	Wholesale price	3,930	-20,880	3,140	-12,070
	Low-carbon support	-11,540	-3,680	-2,150	5,300
	Capacity payments	1,180	13,100	1,030	16,800
	Producer costs	10,640	10,410	7,920	8,590
	Change in Producer Surplus	**4,211**	**-1,060**	**9,940**	**18,620**

471. For simplicity, the changes in unserved energy and demand side response and revenues from environmental taxation are not split out in the table above. They are, however, included in the total surplus figures. The changes to unserved energy and demand side response are minor and similar across the four packages, and so are the revenues to Government

472. The modelling suggests that consumers could be worse off in the Premium FiT packages, compared to the updated baseline, but better off in the FiT CfD packages.

(a) FiT CfD package with Strategic Reserve

473. In the case of the FiT CfD – SR package, there are transfers from consumers to producers in terms of higher wholesale prices and capacity payments, relative to the baseline. These losses to consumer surplus, however, are outweighed by the much lower low-carbon payments paid by consumers in this package than in the baseline. In other words, the cost to consumers of incentivising investment in renewables and low-carbon technologies are lower under the FiT CfD packages than the support cost associated with continuing the Renewables Obligation under the updated baseline (which is assumed to bring on sufficient renewable plant to meet 35% renewables share of electricity generation in 2030). This reduction in the level of low-

carbon support borne by consumers in the FiT CfD package means that the overall change to consumer surplus is positive.

(b) Premium FiT package with Strategic Reserve

474. The direction of transfers are the same under the Premium FiT – SR package as in the FiT CfD -SR package described in paragraph 473, and the increase in wholesale electricity costs and capacity payments are of similar scale as in this package. However, the reductions in low-carbon payments paid by consumers relative to the updated baseline is smaller than it is under the FiT CfD-SR package, so that the overall net impact on consumer surplus is negative. In other words, consumers pay more to incentivise sufficient levels of low-carbon plant to meet indicative decarbonisation targets under the Premium FiT- SR package than under the FiT CfD – SR package.

(c) Packages with Reliability Market

475. The introduction of a market wide Reliability Market mechanism, as modelled, leads to large transfers between consumers and producers in addition to the transfers that are occurring as a result of the low-carbon instrument described above.

476. In the case of Reliability Markets with a FiT CfD , we see large transfers to consumers from producers and in the case of a Premium FiT we see the opposite effect with transfers from consumers to producers.

477. The reason for this is nothing to do with the inherent nature of a FiT CfD or a Premium FiT, but is the result of the wholesale market conditions into which the Reliability Market is introduced. In the FiT CfD scenario as modelled, capacity margins are tight without a Capacity Mechanism. When margins are tight producers receive more surplus as they can receive scarcity rents. In this scenario, the introduction of a Reliability Market serves to mitigate these transfers by reducing that scarcity.

478. In the Premium FiT scenario, the market is not so tight meaning that the benefits to consumers of reducing scarcity is lower. In addition, some existing generators who would otherwise be making losses are able to extract surplus from the Reliability Market which they wouldn't otherwise have been able to do.

479. It is important not to read too much into these figures and in particular, not to come to the conclusion that a Reliability Market could not work with a Premium FiT. The important conclusion to draw is that a Reliability Market produces most benefits to consumers when there is scarcity in the market.

5.2.2 Economic rent

480. The FiT CfD gives lower economic rent to generation plant than the Premium FiT under all scenarios. Economic rent is defined here as the additional revenues earned by investors above the level required to cover Long Run Marginal Costs of their plant.

481. This is explained by the fact that under FiT CfDs generators are not able to benefit from rising electricity prices (under the baseline as well as under different fossil fuel price assumptions), and hence generation sector profitability is lower.

482. The modelling results support this (Table 26 below): under all scenarios, generation sector profitability is lower under a FiT CfD than a PFiT. (Lower fossil fuel prices would lead to lower rents for PFiTs; however all DECC fossil fuel price scenarios have increasing prices.)

483. In the high fossil fuel price scenario the FiT CfD's ability to insulate consumers from rising prices is particularly striking: rents are £18.1bn smaller over the period than under a Premium FiT.

Table 26: Economic rent to new generators under different fossil fuel price scenarios (NPV 2010-2030, real 2009)

Central fossil fuel prices		
Updated baseline	**FiT CfD - SR**	**Premium FiT - SR**
£13.3bn	£9.5bn	£17.3bn
High fossil fuel prices		
Updated baseline	**FiT CfD - SR**	**Premium FiT - SR**
£26.5bn	£8.8bn	£26.9bn
Low fossil fuel prices		
Updated baseline	**FiT CfD - SR**	**Premium FiT - SR**
£10.7bn	£9.5bn	£11.5bn

484. Rents are nonetheless positive under a FiT CfD. This is because:

- FiT CfD tariffs are set such that we achieve 29% and 35% renewables in generation. Since developers have different costs of capital, there will always be some rent for those who borrow more cheaply than others.
- The FiT CfD strike price for high (29% Load Factor), medium (27% Load Factor) and low (21% Load Factor)-yield onshore wind is the same (and is set at the level just above the LRMC of low-yield onshore wind, as currently with ROC bands). As such, there exists some rent for high-and medium-yield onshore wind projects (similar to reality).

485. Overall, the analysis suggests that there is much less risk of producers realising high economic rent under the FiT CfD than under the Premium FiT option under all fossil fuel price scenarios. In particular, there is a risk of economic rent to producers being over three times higher with the Premium FiT than the FiT CfD option under high fossil fuel prices.

5.2.3 Bills

486. Final consumer electricity bills are made up of wholesale energy costs, network costs, metering and other supply costs, supplier margins, VAT and the impacts of energy and climate change policies. Wholesale electricity prices, and therefore also bills, are also strongly influenced by the prevailing capacity margin in the wholesale electricity market.

487. EMR policies affect electricity bills in three main ways:

- **EMR support costs**: FiT CfD or Premium FiT low-carbon payments and capacity payments which are assumed to be funded through electricity bills (green bar in Figure 16 and Figure 17)
- **Lower RO support costs**: less new generation will be covered by the Renewable Obligation (captured by red bar in Figure 16 and Figure 17[63])

[63] The non-EMR costs include transmission, distribution and metering costs, supplier costs and margins, VAT and the impact of other energy and climate change policies (including the RO).

- **Wholesale price effect**: resulting from changed generation mix and capacity margins (purple bar in Figure 16 and Figure 17)

488. The direct EMR support costs would increase retail prices against the baseline[64] as it is assumed that the support costs are passed on to consumers by suppliers. Nevertheless, the introduction of FiT CfDs or Premium FiTs also lead to a reduction in the Renewable Obligation cost against the baseline because relatively fewer plant will receive RO payments.

489. The impact on wholesale prices relative to the baseline varies between packages and between years. In general, one would expect a decarbonised electricity system to result in a lower average wholesale price due to a higher proportion of capacity having a relatively low short run marginal cost and also a reduced marginal impact of the carbon price (and Carbon Price Floor) compared to a baseline case with a higher carbon intensity generation mix.

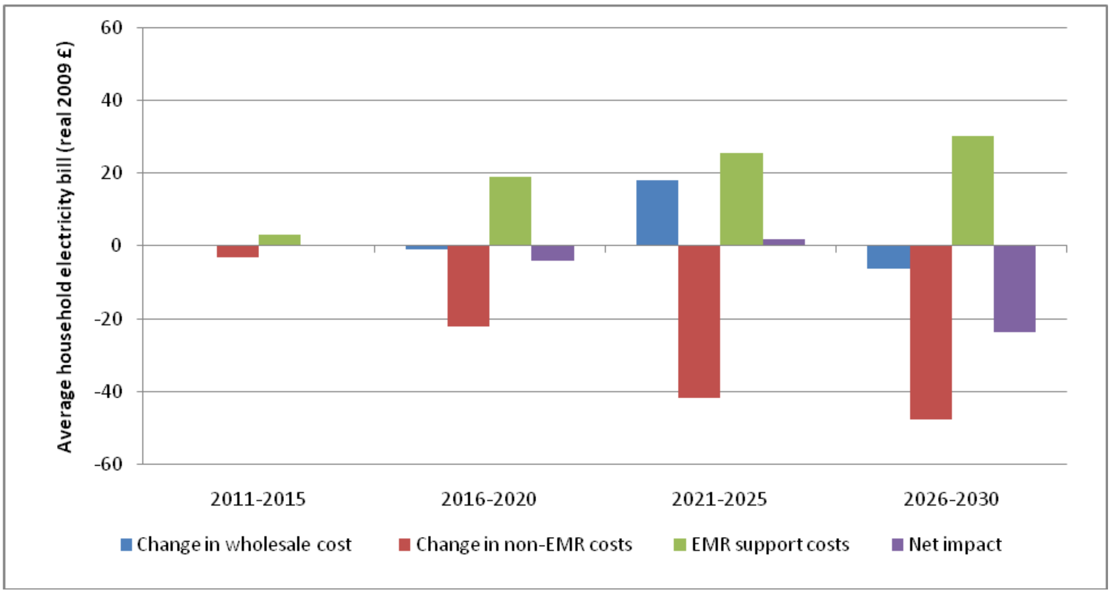
490. In addition, the EMR policies could affect the capacity margin on the system. In some periods, the EMR package could deliver larger capacity margins than in the baseline, and therefore contribute to a dampening effect on wholesale prices. In other periods, the EMR package could deliver a lower capacity margin than in the baseline, and result in a higher wholesale price than in the baseline, for example in the period 2021-2025 under the FiT CfD – SR package as modelled.

491. The net impacts, relative to the baseline, of the Premium FiT and FiT CfD packages on average household electricity bills broken down into the components described above are shown in Figure 16 and Figure 17. Although the scale of the absolute impacts in the Figures below is for an average household, the same impacts (and direction of impacts), as described in the preceding paragraphs, apply to non-domestic users (including energy intensive users[65]) and are reflected in the net impacts on these user's average electricity bills presented in section 5.2.3.i . Note that we are only investigating the choice of FiT. For more detail on the impact of the choice of Capacity Mechanism, see Section 4.

Figure 16 Net impact of FiT CfD with Strategic Reserve relative to baseline on an average annual household electricity bill – central fossil fuel prices

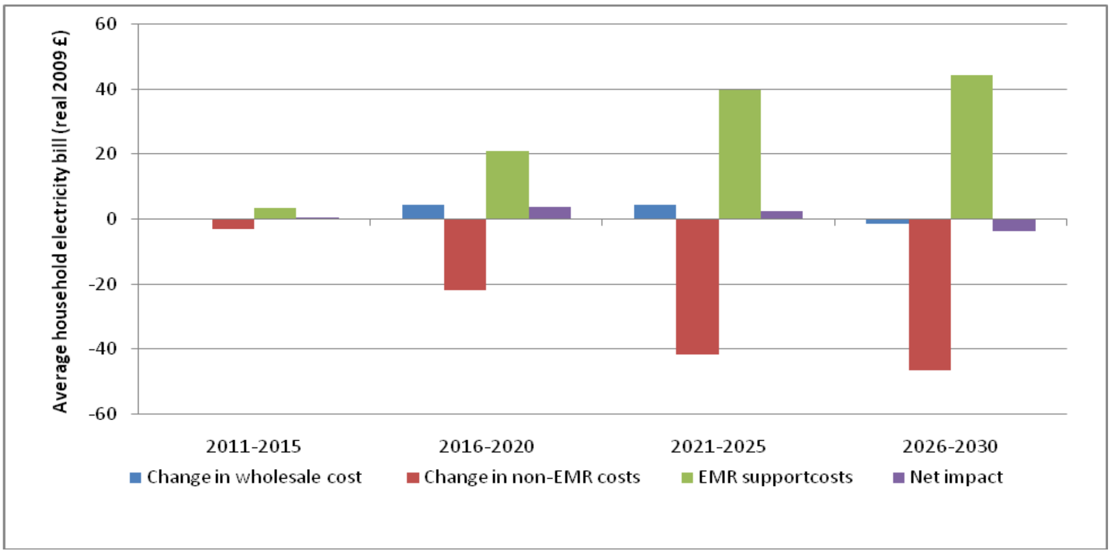
[64] The baseline for all users includes the impact of the Existing and Extended RO, Carbon Price Floor, Feed-in-Tariffs, EU Emissions Trading System and EU Minimum Efficiency Standards for Energy using Products. In addition, the baseline bill for the average household includes the impact of Smart meters, Community Energy Saving Programme, Carbon Emissions Reduction Target (CERT), CERT Extension, a Future Supplier Obligation following CERT, Better Billing, and Security measures. The baseline bill for the non-domestic users includes the impact of the full rate of CCL, CRC and CCAs. The baseline bill for illustrative energy intensive users includes the impact of the discounted rate of CCL for CCA users and CCAs.

[65] The estimated absolute impact of the EMR on the electricity bill of a large energy intensive user is an upper bound estimate assuming policy subsidy costs are distributed evenly across all electricity users (including households) on a per unit basis by retail energy suppliers. This is a simplifying assumption. Suppliers may choose a different strategy for spreading policy subsidy costs across different types of users depending on the differing nature of competition across different types of electricity customers and the nature of the policy.



Source: DECC 2011

Figure 17 Net impact of Premium FiT with Strategic Reserve relative to baseline on an average annual household electricity bill – central fossil fuel prices



Source: DECC 2011

492. An assessment of the combined effect of all energy and climate change policies including those aimed at decarbonising the electricity system will be published later in the year alongside the Annual Energy Statement.

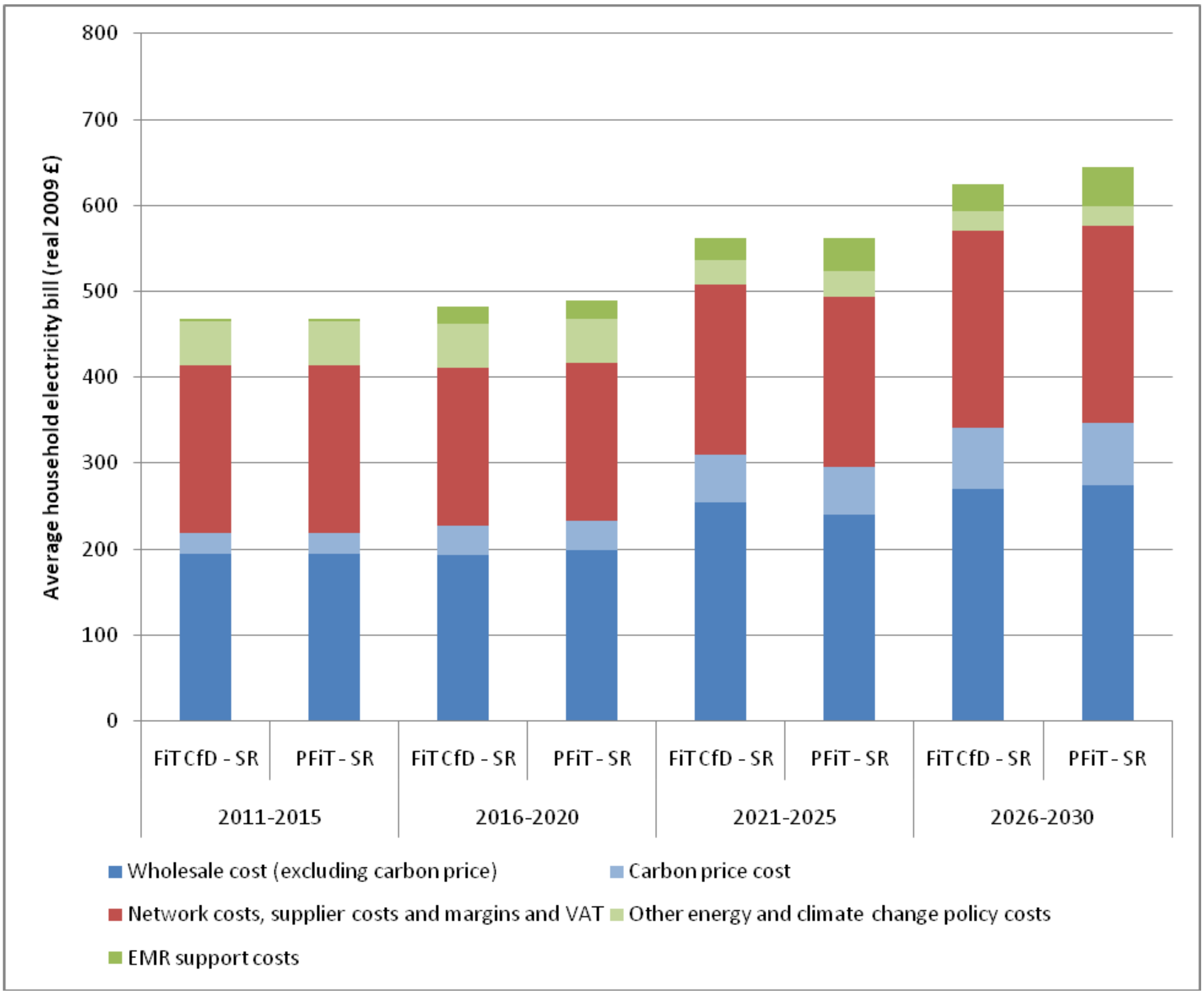
5.2.3.i Bills under central fossil fuel prices

493. Electricity bills are likely to increase over the next decade with or without EMR policies. This is reflected in the estimated increase in the baseline bill over the period 2011-2030. This estimated increase is largely driven by estimated increases in the wholesale cost of energy (driven by rising gas prices) as well as rising carbon prices (including the Carbon Price Floor policy), increasing network costs and increased ambition of other energy and climate change policies (including the RO).

494. The estimated baseline annual domestic electricity bill could increase by just under £200 from now until 2030, whilst for example under the FiT CfD packages for reform, this increase could be reduced to around £160.

495. For illustration, Figure 18 below shows the breakdown of the estimated final average household electricity bill in the five year periods in the FiT CfD and Premium FiT packages with a Strategic Reserve.

Figure 18 Average domestic electricity bills under EMR packages with strategic reserve – central fossil fuel prices



Source: DECC 2011

496. Table 27 suggests that the overall average impact on bills to 2030 is small relative to the baseline. However, it does suggest that the FiT CfD package has lower consumer bills than packages with a Premium FiT. The impact of the choice of Capacity Mechanism is discussed in Section 4. The impact on bills is similar in percentage terms across domestic, non-domestic and Energy Intensive Industry consumers. A full assessment of this is shown in Annex J.

Table 27 Impact of EMR packages on average annual consumer electricity bills (real 2009£) – central fossil fuel prices

Difference from	**FiT CfD – SR**	**FiT CfD - RM**	**PFiT - SR**	**PFiT - RM**

baseline bill Average 2010-2030				
Domestic	-1% (-£6)	-2% (-£10)	0% (£1)	1% (£6)
Medium-sized non-domestic[66]	-1% (-£17,000)	-2% (-£28,000)	0% (£2,000)	1% (£18,000)
Large energy intensive Industrial[67]	-2% (-£154,000)	-3% (-£265,000)	0% (£20,000)	2% (£176,000)

497. It is assumed that EMR policies do not have a direct impact on electricity consumption. Furthermore, when modelling the impact on prices and bills, a conservative assumption of zero elasticity of demand has been used. Therefore, the price impacts are the same in percentage terms as the impact on bills. For completeness, Table 28 shows the average impact on electricity prices for the three electricity consumer groups for the period to 2030 as a whole. A more detailed breakdown of price impacts is shown in Annex J.

Table 28 Impact of EMR packages on average electricity prices (£/MWh, real 2009) – central fossil fuel prices

Difference from baseline price Average 2010-2030	**FiT CfD – SR**	**FiT CfD - RM**	**PFiT - SR**	**PFiT - RM**
Domestic	-£2/MWh	-£3/MWh	£0/MWh	£2/MWh
Medium-sized non-domestic	-£2/MWh	-£3/MWh	£0/MWh	£2/MWh
Large energy intensive Industrial	-£2/MWh	-£3/MWh	£0/MWh	£2/MWh

5.2.3.ii Bills under high fossil fuel prices

498. Under higher fossil fuel prices (particularly gas), consumers could benefit from relatively lower bills on average under both packages for EMR, compared to the baseline bill, over the whole period to 2030. This benefit is greatest under the FiT CfD package, where consumer bills could be 6 per cent lower than the baseline bill over this period whilst in the Premium FiT package, bills could be one per cent lower than the baseline bill over the same period.

Table 29 Impact of EMR packages on average annual consumer electricity bills (real 2009 £) – high fossil fuel prices

Difference from baseline bill Average 2010-2030	FiT CfD – SR	PFiT - SR
Domestic	-6% (-£33)	-1% (-£6)

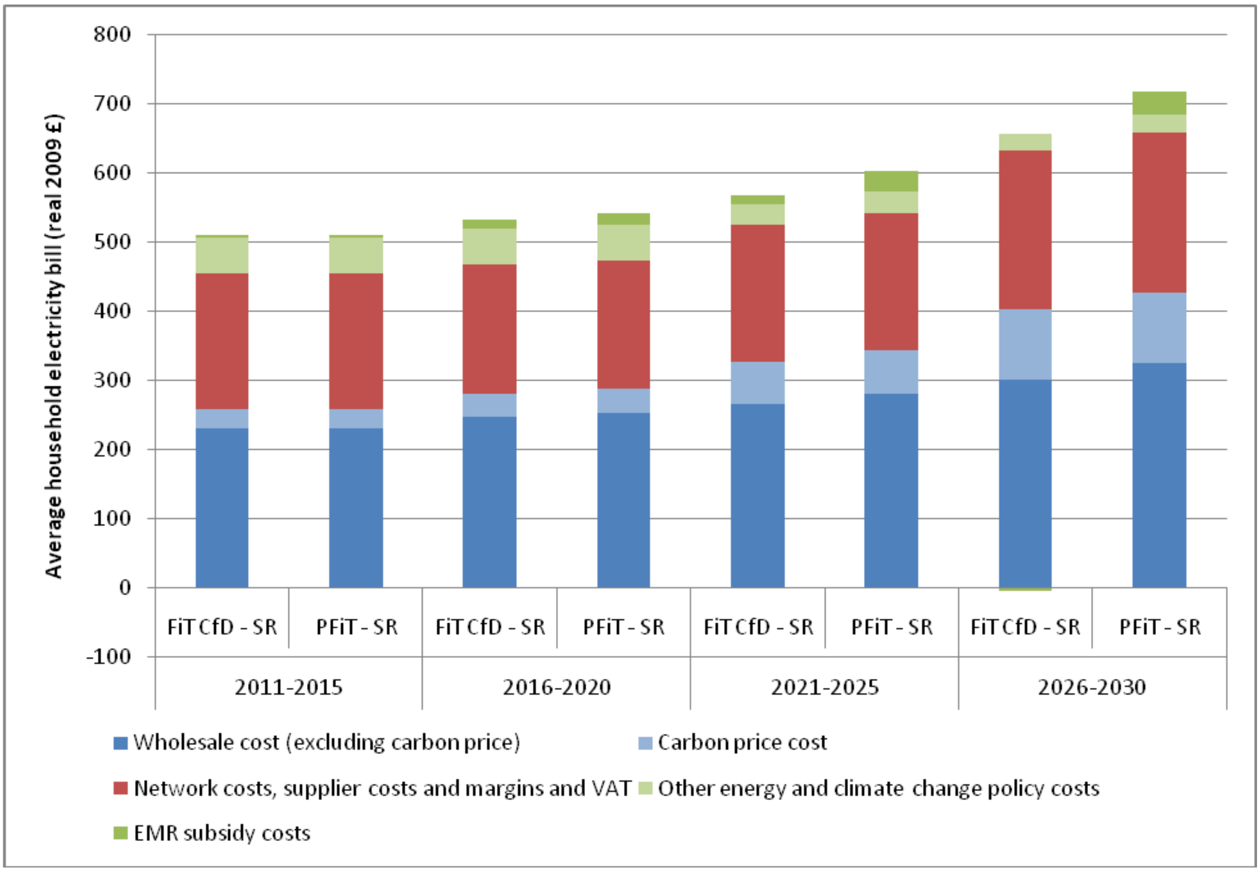
[66] Medium-sized non-domestic users are assumed to have an annual electricity consumption before energy efficiency policies of 11,000MWh, consistent with the midpoint of the Eurostat “medium” size-band for non-domestic electricity consumption.

[67] Electricity consumption for an illustrative Energy Intensive user is assumed to be 100,000MWh before efficiency savings. The percentage impacts also apply for different scales of energy intensive users (as long as they consume above the Eurostat lower bound of 8,800MWh of electricity), while the absolute impacts are scalable – e.g. The results show that the impact of the FiT CfD package with SR on the user’s average electricity bill over the period 2010-2030 is estimated to be -2% (-£154,000). For a user consuming 200,000MWh of electricity, the impact of the FiT CfD package with SR would be -2% (200,000/100,000 x -154,000 = -£308,000).

Medium-sized non-domestic	-7% (-£94,000)	-1% (-£19,000)
Large energy intensive industrial	-8% (-£864,000)	-2% (-£174,000)

499. Figure 19 below shows estimated annual average household electricity bills in the 5 year periods to 2030. Under higher fossil fuel prices, outturn wholesale electricity prices are higher. This means that the FiT CfD top-up would be lower and in some years negative due to the two-way nature of the FiT CfD.

Figure 19 Average annual household electricity bills under EMR packages with strategic reserve – high fossil fuel prices



Source: DECC 2011

5.2.3.iii Bills under low fossil fuel prices

500. Average electricity bills in the Premium FiT package could be marginally lower (1 per cent) than the baseline over the period to 2030 as a whole under lower fossil fuel prices (particularly gas), whilst bills under the FiT CfD package could be somewhat (2 per cent) higher than the baseline bill, as shown in Table 30 below.

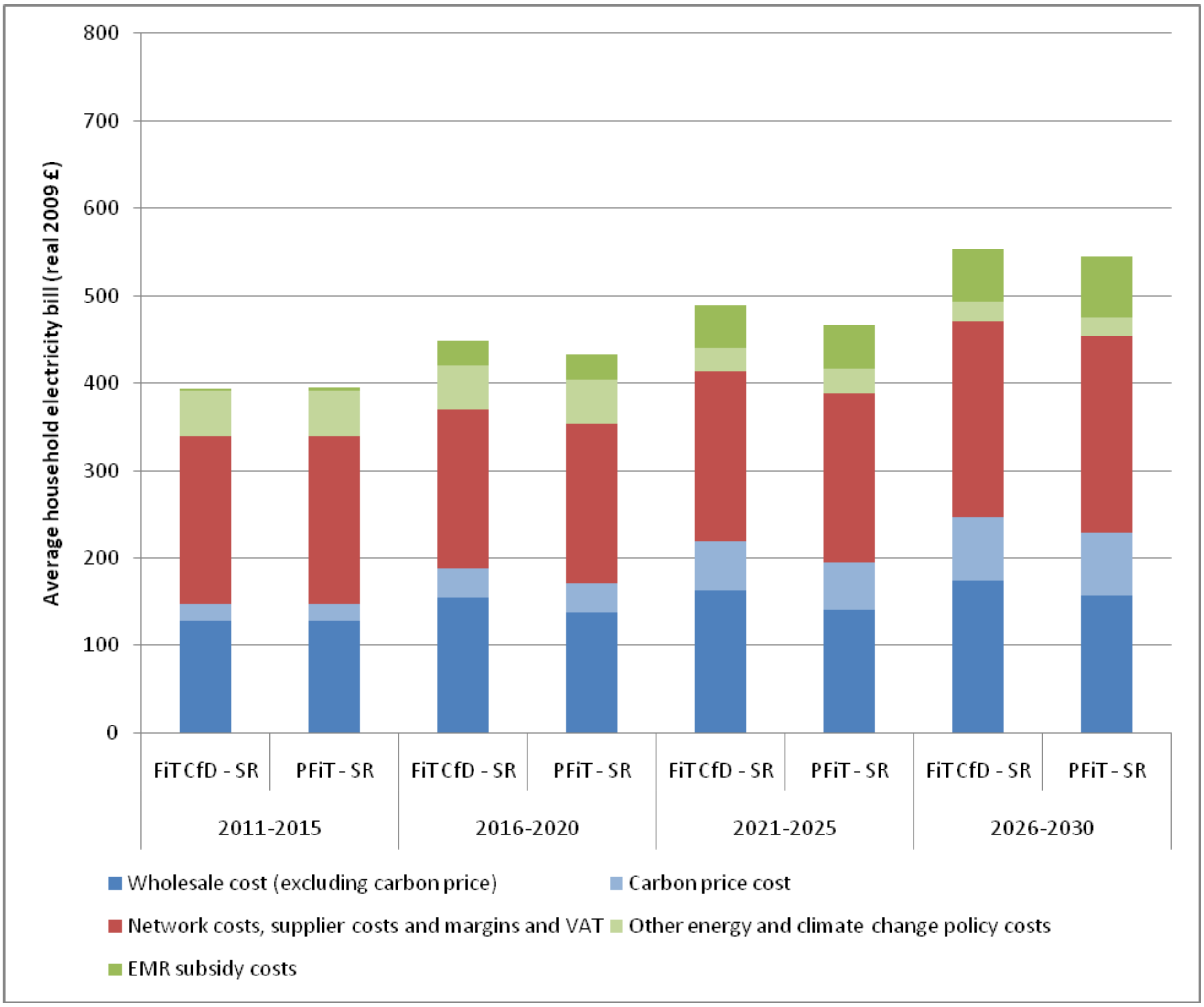
501. The higher bills in the FiT CfD package compared to the Premium FiT package are due to higher wholesale costs in the former package. This, in turn, is partly explained by tight capacity margins. The reason for the relatively lower prices in the Premium FiT package, relative to the baseline, is due to the larger capacity margins on average in this scenario. As previously explained, the prevailing capacity margins in the modelling will not be a direct result of the choice of Feed-in-Tariff mechanism.

Table 30 Impact of EMR packages on average annual consumer electricity bills (real 2009£) - Low fossil fuel prices

Difference from baseline bill Average 2010-2030	FiT CfD – SR	PFiT - SR
Domestic	2% (£8)	-1% (-£3)
Medium-sized non-domestic	2% (£24,000)	-1% (-£8,000)
Large energy intensive industrial	3% (£220,000)	-1% (-£75,000)

502. Figure 20 shows estimated average annual household electricity bill in the two packages with Strategic Reserve under low fossil fuel prices.

Figure 20 Average domestic electricity bills under EMR packages with strategic reserve – low fossil fuel prices



Source: DECC 2011

5.2.3.iv Summary of impact on bills

503. This assessment of the options for reform shows that that the impact on electricity bills is more favourable under the FiT CfD packages under central and, to a larger extent, high fossil fuel prices. Under low fossil fuel prices, however, a Premium FiT package is more favourable compared to the FiT CfD package. Nevertheless, the difference between the two packages is

greatest under high fossil fuel prices. Therefore, if one does not assume a difference in the probability of fossil fuel prices being high, central or low, overall a FiT CfD package is more favourable from an impact on bills perspective.

504. Further details on estimated electricity bills under a FiT CfD and Premium FiT package with Strategic Reserve for domestic, non-domestic and energy intensive industrial users under high and low fossil fuel prices are presented in Annex J.

5.2.3.v Impact on Energy Intensive Industry (EII)

505. Changes to average annual electricity bills are similar in percentage terms between non-domestic consumers and Energy Intensive Industries. However, any impact for Energy Intensive Industries could be felt more than for less energy intensive sectors of the economy because their energy costs can be a very large share of their operating costs. Estimates for the impact on average annual electricity bills for large energy intensive industrial electricity consumers are set shown in Table 27, Table 29 and Table 30 above, and more details are provided in Annex J.

506. As set out in the recent 4th Carbon Budget Statement, Government will announce by the end of the year a package of measures for the EII sector whose international competitiveness is most affected by UK energy and climate change policies, focussing on reducing the impact of Government policy on the cost of electricity for those business which are critical to our growth agenda.

507. As discussed in paragraph 492, the cumulative impacts of climate change and energy policies on electricity prices and bills paid by end users, including illustrative energy intensive users, will be published alongside DECC's Annual Energy Statement.

5.2.4 Distributional analysis of impact on bills

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

509. 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.

510. The following analysis assesses the distributional impacts by income group and across regions under central fossil fuel price assumptions. Actual impacts could be positive or negative, and will heavily dependent on fossil fuels prices.

511. To be consistent with the impact on bills analysis presented above, the distributional analysis below is also presented as the average impacts over a 5 year period , specifically, the average impact is shown over the period 2016 to 2020. It is also important to notice the scale of charts presented below, as the effect on electricity spending as a share of total expenditure is very small in all packages. The analysis is, as above, relative to a baseline that includes all current energy and climate change policies, including the RO and the Carbon Price Floor.

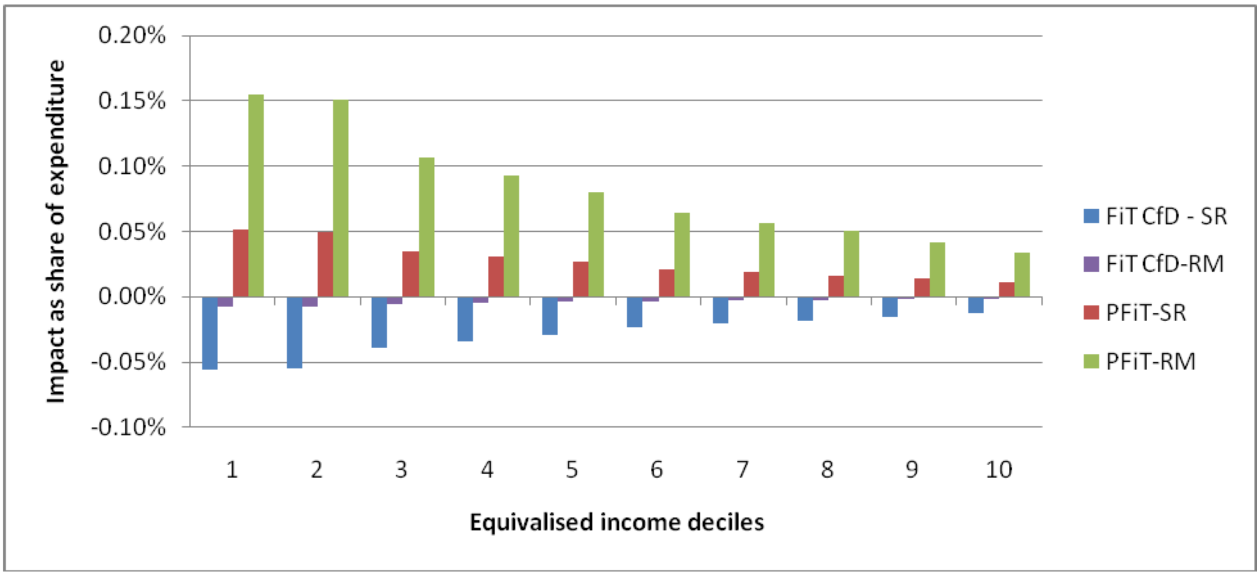
5.2.4.i Impact by income group

512. Consumers save money on electricity bills under the FiT CfD – SR scenario, relative to the baseline, in the period 2016-2020. The distributional analysis below shows that the FiT CfD – SR

package reduces expenditure on electricity as a share of total expenditure (relative to the baseline) across all income groups. This effect is largest in the bottom income decile, where consumers would save 0.06% of their expenditure on electricity under the FiT CfD – SR scenario compared to the baseline.

513. Comparing the options suggests that the impact as a share of expenditure is highest in the Premium FiT – RM package for all income groups (see Figure 21). It is estimated that households in the bottom decile would spend an extra 0.2% of their expenditure on electricity compared with the baseline under this option.

Figure 21: Impact of EMR packages on expenditure across income declines in the period 2016-2020[68]



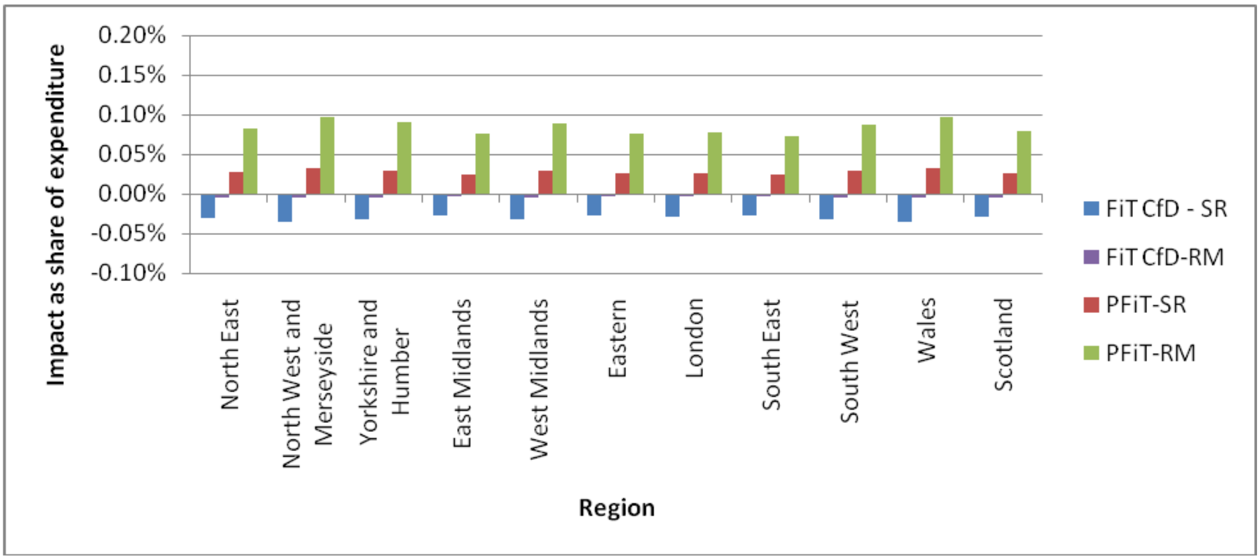
Source: DECC 2011

5.2.4.ii Impact by region

514. The impact in terms of share of expenditure spent on electricity in the five year period to 2020, also varies across regions. Under the FiT CfD – SR package, there could be an 0.04% saving in expenditure on electricity in Wales and North West and Merseyside. The greatest impact would be in the same regions in the Premium FiT – RM package where households would spend an extra 0.10 per cent of their expenditure on electricity.

[68] Income decile 1 refers to households in the lowest group of disposable income when the total population of households is divided into ten equal groups and ranked by disposable income (decile 10 refers to the top 10 per cent).

Figure 22: Impact of EMR packages electricity expenditure in the period 2016-2020 across regions



Source: DECC 2011

5.2.4.iii Impact on fuel poverty

515. Estimates of the impact on the four packages above on fuel poverty, as defined for the purpose of the Warm Homes and Energy Conservation Act 2000[69], in England in 2015, 2020, 2025 and 2030 are shown in Table 31 below. The table shows the impact of the EMR policy packages in isolation; negative numbers show a reduction in fuel poverty (where electricity bills are projected to fall).

516. Estimates for the next decade should be treated with caution as it is likely that by then, the housing stock will be considerably better insulated than now, which would mean that the impacts shown below may be too high.

Table 31: Impact on fuel poverty in England per year (number of households)

	FiT CfD - SR CPF	**FIT CFD - RM** CPF	**Premium FiT - SR** CPF	**Premium FiT - RM** CPF
2015	Negligible	Negligible	0 – 10,000	10,000 – 50,000
2020	-100,000 – -25,000	-50,000 – -25,000	0 – 10,000	100,000 – 150,000
2025	150,000 – 250,000	-75,000 – -25,000	10,000 – 40,000	50,000 – 100,000
2030	-300,000 – -175,000	-300,000 – -175,000	-275,000 – -150,000	-75,000 – 0

517. The number of households in fuel poverty in England is currently projected to be 4 million in 2010[70]. The Government is committed to eliminating fuel poverty in England by 2016, as far is reasonably practicable, as well as ensuring secure and affordable energy supplies.

5.2.5 Public finance implications

518. The low-carbon support mechanism requires payments to generators and these are likely to fall under the definition used by the Office for National Statistics for spending and taxation. This means that the payments will appear in the public finance aggregates. Figure 5 shows the

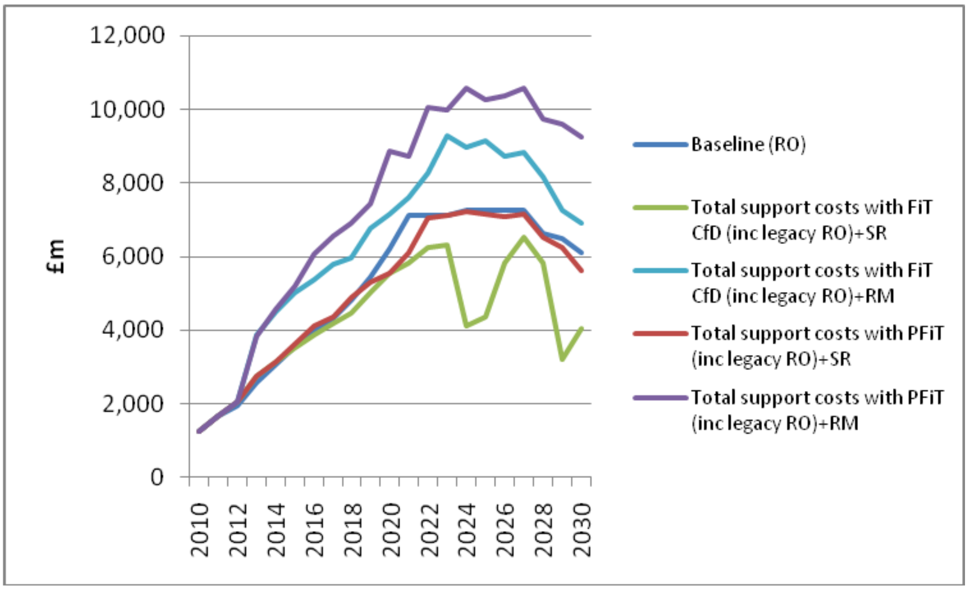
[69] Fuel poverty is defined as households who spend at least 10 per cent of their income on fuel in order to achieve an adequate standard warmth (21 degrees Celsius in the main living area, 18 degrees Celsius elsewhere).
[70] DECC, Fuel Poverty Statistics, 2010

support costs of the low-carbon options (including legacy costs from the Renewables Obligation (RO)) in the central case compared to the baseline (with RO).

519. Figure 23 below shows the total support costs for the EMR policies under the following cases:

- Current policies (which hit targets for renewables but not decarbonisation);
- a FiT CfD (to hit both targets) with a Capacity Mechanism and legacy RO costs; and
- a Premium FiT (to hit both targets) with a Capacity Mechanism and legacy RO costs.

Figure 23: Cost of support of EMR packages



Source: EMR Redpoint analysis

520. The baseline shows the support costs of existing policy (RO) which delivers on the renewables target but not decarbonisation. The EMR package with Premium FiT and SR delivers on both targets at a similar support cost to the baseline. The EMR package with a FiT CfD and SR also delivers on both targets at 20% less average cost, but with more year-to-year variation. However for both packages where the Capacity Mechanism is an RM there is an overall increase in support costs because of the way the transfer of funds under an RM is accounted. See section 4 for more detail.

521. The cost of the EMR options will vary with the volume of output delivered and the support levels for each technology. In particular, the cost of a FiT with FiT CfD will be inversely related to the wholesale electricity price. Wholesale electricity prices are driven by the dynamics of the electricity market and input fuel prices. Therefore there is likely to be some degree of volatility in annual support costs.

522. There is a clear trade-off between the public finance support volatility of the FIT CFD and the risk of high economic rents to generators under a Premium FiT. As discussed, the cost in terms of public finances of FiT CfD option for low-carbon support is likely to be more volatile and uncertain than the cost under a Premium FiT. However, future support costs of a Premium FiT are also uncertain as future premium will need to be adjusted in the light of changes to the

wholesale price. Nevertheless, the volatility of public spending on low-carbon support under a Premium FiT would be relatively low on a year-to-year basis.

5.2.6 Impacts on business

523. The assessment of costs and benefits to business of the EMR packages is based on distributional analysis from Redpoint modelling together with an assessment of the administrative costs to business of implementing the policies.

524. Based on the distributional analysis[71] for each of the package options, the business element of the consumer surplus is ascertained using an apportioning factor based on business energy consumption as a percentage of total energy consumption (an estimate of 61% is derived based on DUKES[72] data). An assessment of the total administrative costs to business is also shown based on the cumulative effects of each policy (discussed in sections below) in addition to the costs to private business from any institutional arrangements which will only be applicable if private businesses are tasked with delivering aspects of the EMR. Where responsibility is assigned elsewhere (e.g. a public body) there is no applicability and costs to private businesses. The overall net effect figures are therefore given as a range to reflect this.

Figure 24: Net impact on business of EMR options, NPV 2010-2030

	FiT CFD , CPF (with SR)	**FiT CFD , CPF (with RM)**	**PFiT ,CPF (with SR)**	**PFiT ,CPF (with RM)**
Benefit to Business	8,336	6,118	8,917	12,781
Less: Admin costs on business (FIT CFD/PFIT +CM)	6-36	11-72	6-36	11-72
Less: Institutional costs on private business *(if applicable)*	29-161	29-161	29-161	29-161
Overall net benefit range to business	8,139 - 8,330	5,885 - 6,107	8,720 - 8,911	12,548 - 12,770

525. As we can see in Figure 24 above, PFiT packages show a higher net benefit to business compared to FiT CfD packages. This is primarily due to the increased rent obtained by generators under PFiT than under FiT CfD. In economic terms, rent is a transfer between consumers of electricity to producers of electricity and therefore is not accounted for separately in the overall net benefit to society. Further discussion of rents is presented in section 5.2 .

526. **FiT CFD packages:** Annex F provides a full assessment and the summary table above and shows the overall net impact on business of a FiT CFD associated package would be a benefit of

[71] Annex F provides further details.
[72] Table 5b, Digest of UK Energy Statistics 2010, DECC

between £5.8bn - £8.3bn or around £0.4bn-0.6bn per year on an equivalised annual basis (EAB) depending on the choice of Capacity Mechanism.

527. **Premium FiT packages:** Similarly Annex F provides a full assessment and the summary table given by Figure 20 shows the overall net impact on business would be a benefit of between £8.7bn – £12.7bn or around £0.59bn – 0.9bn per year on an EAB depending on the choice of Capacity Mechanism.

5.2.6.i Administrative costs on business

528. **CM SR***:* For a strategic reserve, most business will be unaffected, since only those energy companies tendering for capacity payments could some incur incremental administrative costs, however many of the required processes are already in place for the Short Term Operating Reserve Requirements in the current market which such businesses can already choose to participate in.

529. **CM RM:** A Reliability Market approach would have an additional impact because there would be a new market for generating companies to participate in. Section 4.3.1.v (c) shows that costs are expected to be between £0.4 - £2.5m per year or a total cost of £5.7m - £36m on a PV basis.

530. **FiT CfD/PFiT :** These options are not expected to result in any significant new costs (see section 3.8 On the cautious assumption that there is likely to be some costs to generators from the registration and negotiation process in the issuance of the FiT CfD or PFiT contract a similar approach to that for the Reliability Market option under the Capacity Mechanism was used and this gives an estimate of £0.4m-£2.5m per year with a total cost of £5.7m -£36m on a PV basis.

5.2.6.ii Institutional set-up and administration costs

531. FiT CfD and CM: There are a number of options around the institutional arrangements for delivering a FiT CfD or PFiT versions of feed in tariff (FiT) and the Capacity Mechanism. The final choice will be confirmed later this year. Where a private business entity undertakes some aspects of that delivery role then there will be a private business cost and this has been included in the business impacts given by Figure 24.

532. The costs of the EMR Institutional establishment and administration would consist of one off and recurring costs. It is not possible at this stage to determine fully what these costs might be as it would depend on the precise responsibility of the institutions the number of employees, IT, location etc. Therefore the following estimates must be regarded as highly illustrative and are very likely to be revised once more detail emerges on the institutional delivery framework. Based on assumptions derived from the DECC Delivery Review some tentative estimates have been made for the purpose of the IA. Using a high and low range around assumptions on employees, location and institutional set up and on-going running costs, provisional costings suggest a range between £2m-£7m for one-off set up cost and £2m-£11m per annum for the running cost. This would imply a total cost of £29m-£161m in PV terms out to 2030.

533. The higher end costs are based on an assumption of around 130 full time employees (FTE), with a London location, this includes a team to set up the organisation over an 18 month period, upfront costs to obtain and fit out a building, funds for an IT platform to manage contracts, new advisory and oversight roles and an annual budget for ongoing external legal, commercial and technical support. Average on-going staff costs for the upper estimate are £60k per FTE.

534. The lower end costs are based on cost savings due to assumed lower FTE requirements (as few as 60), a location in an existing building outside London with lower leasing charges, lower IT platform costs and lower levels of external support. Average on-going staff costs were also reduced by £5k per FTE, so the total staff cost becomes approximately £55k per FTE.

5.2.7 Impact on small firms

535. Depending on choice of EMR policy package, the measures could lead to either a marginal increase or decrease in average annual electricity bills for all energy consumers. Detail in terms of the specific bill impact on small businesses is not available however a reasonable assumption would be that bill impacts would fall between that of domestic users and medium usage business users. As shown in the impacts on bills section (in the central case), depending on the choice of EMR package, this could mean either average bill increases of up to 1% or reductions in average bills of up to 2% for small businesses. However in terms of the preferred FiT CFD associated policy package small businesses could see a fall in average bills of up to 2% compared to the baseline in the central case.

536. In terms of additional regulatory or administrative burdens, EMR policies on low-carbon support and Capacity Mechanism will impact electricity generators in the sector, these will be classed as large businesses, so no impact on small firms or micro-business are expected in this regard. Moreover it is also worth noting that small scale generators/businesses (which have up to 5MW of capacity) can already participate in the small scale FiT, hence as an additional point the low-carbon incentive aspect of the policy will not have impacted small or micro-businesses in any case.

537. The Capacity Mechanism is only expected to impact on large businesses, however the option could reduce barriers to new demand side providers, in this regard it could assist any new entrant small businesses wishing to participate in the market.

5.3 Nature of the market

5.3.1 Decarbonisation trajectories

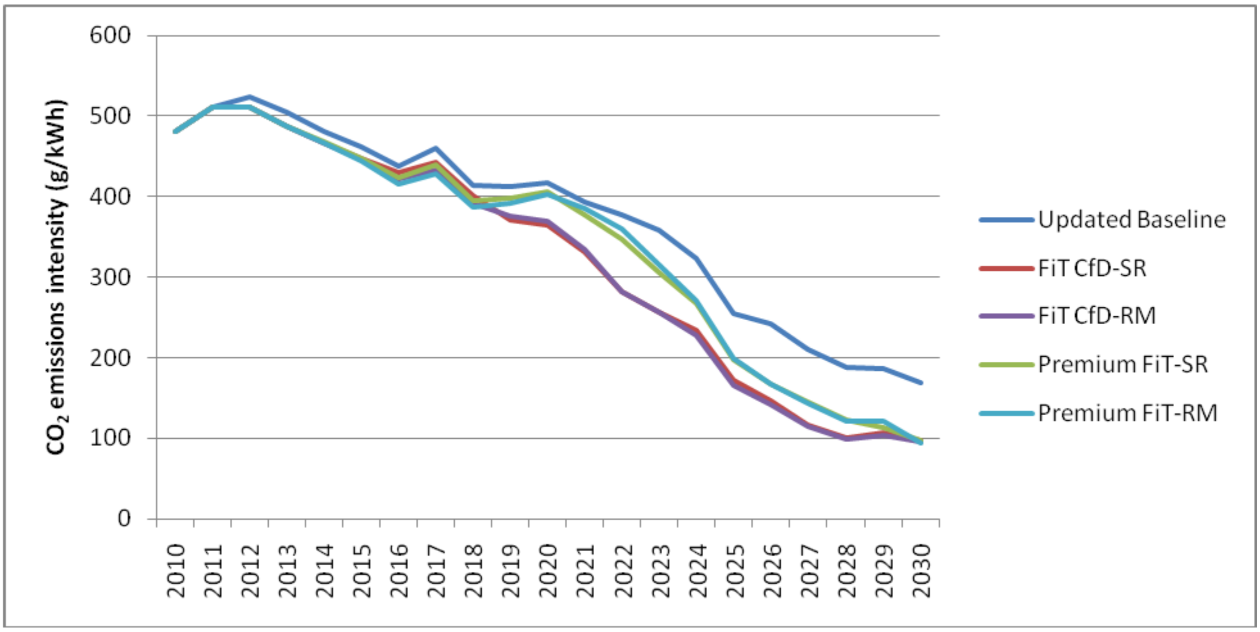
538. In the quantitative analysis undertaken by Redpoint Energy for DECC all four EMR packages were modelled to reach a $100gCO_2/kWh$ carbon emission intensity of the power sector by 2030.

539. $100gCO_2/kWh$ in 2030 is an indicative target level consistent with modelling for the EMR consultation document and with the previous recommendation for the power sector from the Committee on Climate Change (CCC). The most recent publication by the CCC for the 4^{th} Carbon Budget, however, recommends decarbonising the power sector to a lower figure of around $50gCO_2/kWh$ in 2030. Sensitivities illustrating this level of decarbonisation are included in this Impact Assessment to assess whether the optimal choice of EMR policies is robust to a range of decarbonisation levels that the Government might choose to commit to.

540. Modelling for the EMR consultation document suggested that, under central fossil fuel price assumptions, the power sector would reach a carbon emissions intensity of over 200g CO_2/kWh in 2030. In the updated EMR modelling, the baseline scenario reaches an intensity of around 170g/kWh. The higher level of decarbonisation in the updated scenario is largely a result of reduced generation from unabated coal plant and higher generation from CCS plant, as a result of the inclusion of the Carbon Price Floor in the updated baseline. The decarbonisation

trajectory for the updated baseline and the four EMR packages, under central fossil fuel price assumptions, are shown in Figure 25 below.

Figure 25: Decarbonisation trajectory to 2030 - central price assumptions

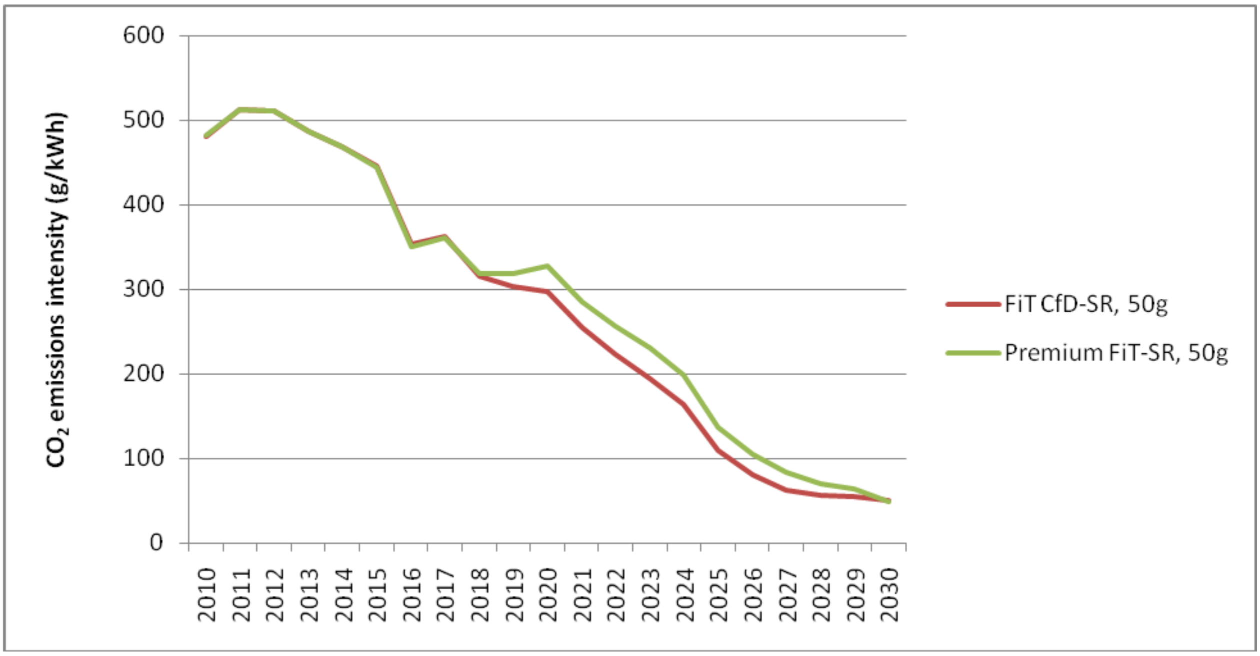


Source: EMR Redpoint analysis

541. As shown in Figure 25 above, decarbonisation happens more rapidly in the two FiT CfD packages than in the Premium FiT packages. This is primarily because increased revenue certainty for low-carbon plant, and hence lower hurdle rates for investment in these technologies, mean that nuclear comes online earlier with a FiT CfD (in 2019) than in the Premium FiT packages (in 2023).

542. As previously discussed, the CCC's most recent recommendation is for a more ambitious decarbonisation trajectory to 2030. Figure 26 below shows the trajectory of decarbonisation of the FiT CfD -SR and Premium FiT - SR packages when these packages are modelled to reach a 50gCO_2/kWh carbon emission intensity in 2030.

Figure 26: Rapid decarbonisation trajectory to 2030 – central fossil fuel price assumptions



Source: EMR Redpoint analysis

543. The difference between the two packages in terms of decarbonisation trajectories is smaller in this scenario than in the 100gCO_2/kWh scenario presented above. This is primarily because the year of first new nuclear deployment is brought forward by two years in the Premium FiT package (from 2021 to 2019) whilst it remains at 2019 for the FiT CfD package. This is because an outcome of Redpoint's investment decision modelling is that the earliest year of new nuclear deployment is 2019[73].

544. Further details on the rapid decarbonisation sensitivity modelling are presented in the sensitivity analysis in section 3.6.4 .

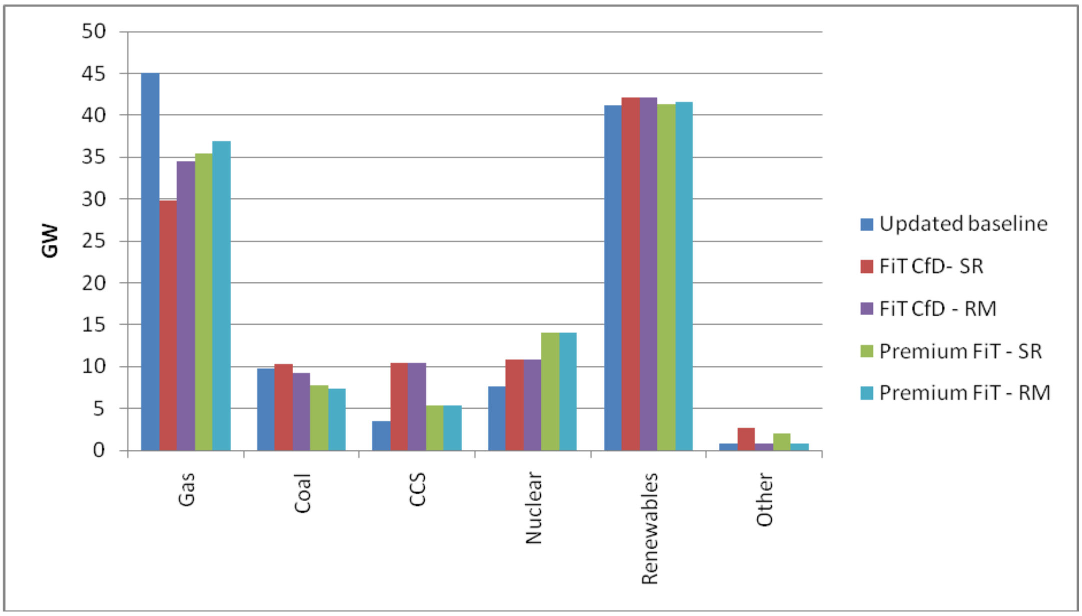
5.3.2 Generation and capacity outcome characteristics

545. Packages for reform to decarbonise the electricity sector naturally result in changed characteristics of the wholesale electricity market. Figure 27 and Figure 28 show revised generation capacity and output projections in 2030 under the EMR policy packages. The charts show the combined effects of the low-carbon and security of supply measures.

546. These figures should be read as illustrative only, as the actual capacity and generation mix going forward will depend on commercial decisions based on market conditions and economics of different technologies, in turn influenced by how the level of incentives will be set for different technologies.

[73] Timescales for the deployment of new nuclear capacity in the UK will be the result of commercial decisions made by private investors. Developers have announced plans to build 16GW of new nuclear capacity in the UK, with the first reactor scheduled to become operational in 2018.

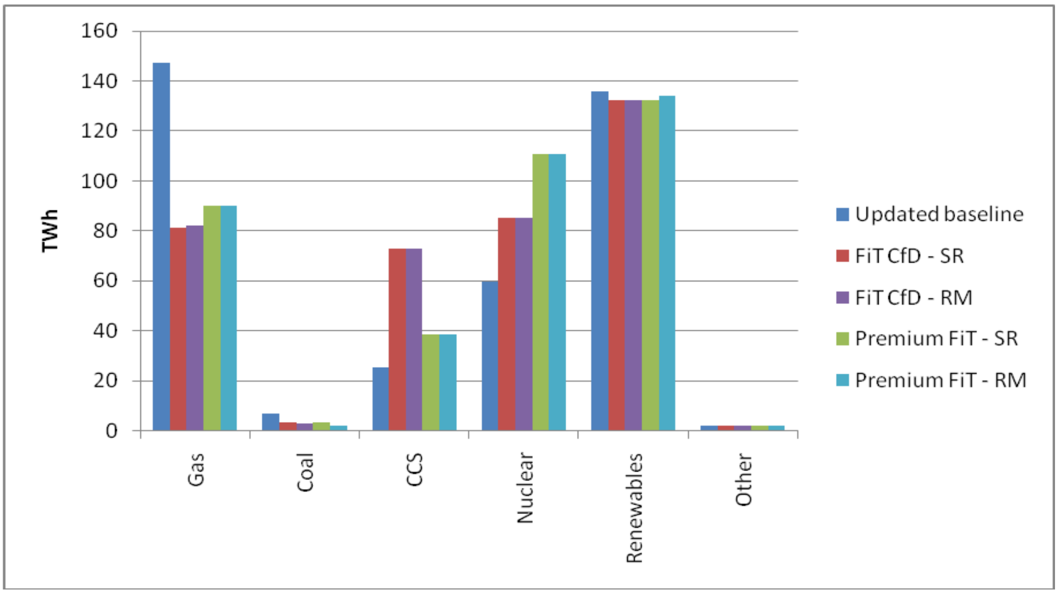
Figure 27: Total capacity in the updated baseline and EMR packages in 2030



Source: EMR Redpoint analysis

547. Low-carbon capacity is generally higher under all policy packages, compared to the update baseline. This is due to the financial support given to investors in low-carbon technologies under the EMR packages. The higher low-carbon capacity is particularly evident for CCS (under the FiT CfD options) and for nuclear (under the Premium FiT options). Levels of wind and biomass capacity are relatively similar in all cases. Overall, low-carbon capacity is projected to contribute around 60% of overall generation capacity in 2030 (compared to just under 50% under the baseline).

Figure 28: Generation output in the updated baseline and EMR packages in 2030



Source: EMR Redpoint analysis

548. As for generation, the contribution of low-carbon plant to overall generation output is expected to increase in general. In aggregate, low-carbon technologies are projected to provide around 75% of overall generation output in 2030 (relative to just under 60% under the

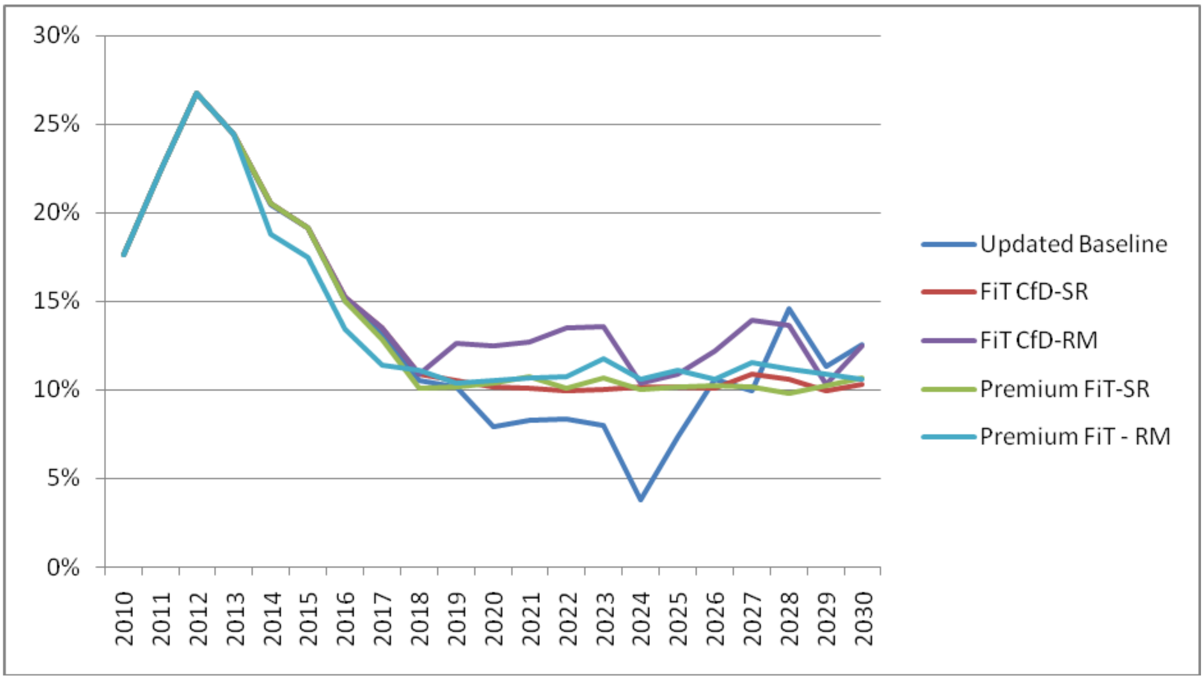
baseline). As previously mentioned, the baseline and packages were all modelled to reach a 29% and 35% share of renewable electricity generation by 2020 and 2030 respectively.

5.3.3 Capacity margin

549. The introduction of a Capacity Mechanism in the packages avoids the fall in de-rated capacity margins below 10% in the 2020s as is predicted to be the case in the updated baseline scenario. Therefore, there are no security of supply problems in the four EMR packages modelled due to this mandatory 10% margin, and therefore minimal risk of energy unserved.

550. Consequently, as can be seen from Figure 29 below, annual de-rated capacity margins in the four packages avoid the dip in capacity margins below 10% that occurs in the baseline scenario. As explained above, all the packages have been modelled specifically to meet a minimum 10% de-rated capacity margin. Furthermore, detailed modelling outputs like large year-on-year fluctuations in capacity margins should be interpreted with caution as capacity margins are an outcome of the prevailing generation electricity mix. A detailed assessment of Capacity Mechanisms and security of supply more generally is provided in section 4.

Figure 29: De-rated capacity margins with tendered plant - %



Source: EMR Redpoint analysis

5.4 Wider impacts

5.4.1 Air quality

551. DEFRA has modelled the impact on air quality of the FiT CfD – SR and the Premium FiT – SR packages and compared those to the air quality impact in the updated Baseline scenario. For this assessment, Redpoint's annual generation output to 2030 in these three scenarios were converted into emissions and combined with impact factors[74] from the UK Integrated

[74] Impact factors represent the relationship between emissions and a number of environmental metrics reflecting impacts on human health and ecosystem damage.

Assessment Model. The impacts on air quality have been assessed using the agreed methodology of the Inter-Departmental Group on the Costs and Benefits of Air Quality[75].

552. DEFRA's analysis found that both packages for reform reduce the impact of air pollution on human health, and that the impact is greatest (i.e. the benefit for human health is highest) in the FiT CfD – SR package. In this package, the central estimate for monetised benefit is £643million (real 2009, NPV 2010-2030). In the Premium FiT – SR package scenario the central estimate for monetised benefit is £442million (real 2009, NPV 2010-2030).

Table 32: Monetised benefits of the EMR scenarios relative to the updated Baseline for impacts in 2025 (NPV 2010-2030, real 2009)

Relative to updated baseline	**FiT CfD – SR** CPF		**Premium FiT – SR** CPF	
	Range	Central	Range	Central
NPV	£505-£732m	£643m	£347-£503m	£442m

553. It should be noted that the benefits presented in Table 32 above only includes the monetised benefits in terms of impact on human health and not on ecosystems or the natural environment. Whilst an assessment of impacts on these are also important for policy appraisal, there is at present not sufficient evidence to monetise these impacts. Impacts on ecosystems or the natural environment is therefore not included in the table of monetised benefits above, but described qualitatively in the below.

554. Poor air quality can have a negative impact on ecosystems. Therefore, an improvement in air quality as a result of both options for reform could improve the impact on ecosystems, relative to the baseline. Both FiT CfD-SR package and the Premium FiT – SR package could improve the impacts on the ecosystems from acidification. However, there could be a *negative* effect on ecosystems as a result of higher ammonia from emissions from CCS plant in the FiT CfD-SR package. Overall, DEFRA's analysis suggests that the Premium FiT - SR package could reduce the impact of air pollution on ecosystems more than both the updated Baseline and the FiT CfD-SR package.

5.4.2 UK Competitiveness

555. EMR measures will affect the relative attractiveness of the UK for investment by overseas investors. Section 3.5.7 discusses the effect of EMR policies on the attractiveness of the UK electricity market to all investors.

556. The competiveness of UK industry is also affected by the bills impacts on business from the EMR measures. As shown in the bills section above (see 5.1.4) depending on the reform package the EMR measures could lead to either a marginal increase or decrease in average energy bills for business consumers. However with the preferred FiT CFD associated policy packages there would be a reduction in bills for business consumers which would range between -1% to -3% relative to the baseline. These bill reductions therefore could marginally enhance the competiveness of UK business relative to the baseline case.

[75] More information on this methodology can be found here http://www.defra.gov.uk/environment/quality/air/air-quality/economic/

5.4.3 Institutions

557. A range of options are being explored on the question of which institutions will deliver the EMR policies. This is partly due to institutional design proceeding in parallel with policy design.

558. For the purpose of the analysis in this Impact Assessment, four options for institutional design have been considered to cover the main organisational variants of options for institutional design:

- An agency or Non Departmental Public Body delivers both the Feed-in Tariff and Capacity Mechanisms
- An agency or Non Departmental Public Body delivers the Feed-in Tariff while a private organisation under licence (such as the System Operator) delivers the Capacity Mechanisms
- An independent public organisation (such as Ofgem) delivers the Feed-in Tariff mechanisms while a private organisation under licence deliver the Capacity Mechanism
- A private organisation under licence delivers both the Feed-in Tariff and Capacity Mechanisms following a tender process and commercial contract negotiation.

559. In each instance the organisation outlined would play the key delivery role with support from organisations such as DECC and Ofgem in, for example, setting strategic outcomes, and providing oversight.

560. In terms of enforcement DECC/Ofgem is expected to enforce the policy and any enforcement will comply with the Hampton principles. Further details on the institutional arrangements will be available later in 2011.

5.4.4 Implications for one-in-one-out

561. Based on the latest HMT advice, the low-carbon and Capacity Mechanisms options that form the EMR are to be treated tax and spend measures so would be out of scope of One-In One-Out (OIOO)[76].

5.4.5 Other specific impacts

562. As our distributional analysis shows there will an impact on different income groups but it does it not affect individuals differentially on account of their protected characteristics. It is not envisaged that the EMR options consulted on will impact measures of **equality** as set out in the Statutory Equality Duties Guidance. Specifically, options would not have different impacts on people of different racial groups, disabled people and men and women, including transsexual men and women. There are also no foreseen adverse impacts of the options on **human rights** and on the **justice** system

563. Impact of the options consulted on by **rurality** is considered in section 5.2.4.ii

564. There could be some **intergenerational** impacts in terms of changes to wholesale electricity prices and electricity bills but these on average are expected to be marginal (see section 5.2.3)

565. We expect this change will contribute to the Government's commitment to **sustainable development**, which consists of five principles:

- Living within environmental limits;
- Ensuring a strong, healthy and just society

[76] http://www.bis.gov.uk/reducing-regulation

- Achieving a sustainable economy
- Promoting good governance; and
- Using sound science responsibly.

Annex A: Post Implementation Review (PIR) Plan

Annex A Post Implementation Review (PIR) Plan

Basis of the review: The Department of Energy and Climate Change intends that the first scheduled review of the Electricity Market Reform (EMR) Programme should take place approximately one year after the first set of Feed-in-Tariff (FIT) payments have begun. The date of the review therefore depends on the timing of legislation to implement the FIT and other EMR measures. It would seem appropriate to have regular reviews subsequently to assess the take-up of the mechanisms by different types of electricity generation and to address significant changes in the environment for different technologies. However, at this (pre-legislative) stage it is too early to put in place a detailed PIR. The department intends to register a full PIR and confirm in detail how EMR will be reviewed, when it publishes draft legislation to implement EMR.
Review objective: This will be confirmed when draft legislation is brought forward.
Review approach and rationale: This will be confirmed when draft legislation is brought forward.
Baseline: This will be confirmed when draft legislation is brought forward.
Success criteria: This will be confirmed when draft legislation is brought forward.
Monitoring information arrangements: This will be confirmed when draft legislation is brought forward.
Reasons for not planning a PIR: N/A – a PIR is under development and will be confirmed when draft legislation is brought forward.

Annex B Transition 2013 – 2017

566. We have consulted on whether a choice of scheme before the RO closes on 31 March 2017 is desirable. Our preferred option is to offer a choice of scheme to all new renewables generation until 31 March 2017, and the RO will remain open to new generation until 31 March 2017. All eligible projects commissioning between the introduction of a FiT CfD and until 31 March 2017 will be given a choice of taking up the RO or the FIT CFD. This gives generators the certainty they need to make their investments over the next few years until support levels under the new scheme are decided. In addition, projects which would only commission with access to a more stable revenue stream are able to do so at an earlier date. We have decided against an open choice for existing generators to transfer to the new mechanism as we deem this choice to have the potential to destabilise the RO mechanism and to make it difficult to set the obligation level each year.

567. The estimated impact of the EMR changes make the simplifying assumption for modelling purposes that all new large-scale renewable projects that would have accredited under the RO, will take up FiT CfDs as soon as the system is up and running, implying all new large-scale renewables generation from 2014 will be under CfD. The costs/ benefits of the EMR in this Impact Assessment reflect that assumption. In practice, this will not necessarily be the case, and we would expect that some new capacity will continue to accredit under the RO its closure to new accreditations in 2017. Factors that will affect that choice will be perceived certainty of the two schemes, and the support levels available under the RO and FiT CfDs. Thus the take up of the two schemes between 2013 and 2017 is uncertain, and the impact on costs is not possible to estimate at this stage, as it will be determined by a number of factors, including the outcome of the RO banding review and future decisions on FiT CfDs. Costs of additional activities to implement FiT CfDs are included in the overall administration costs of this IA administration costs from this proposal are likely to have a negligible impact on overall administration costs.

Calculating the obligation

568. We have consulted on three options of how to calculate the obligation once the RO scheme becomes closed to new generation on 31 March 2017. Our preferred option is the proposed hybrid option of calculating the obligation using “headroom” until 2027 and use a fixed ROC from 2027 onwards. This option is least disruptive to current PPA arrangements, as the majority of existing PPAs will have expired by 2027. Therefore, this will provide most certainty to existing investors. There will also be a reduced administration burden from 2027 when no further calculation of the obligation is required. Furthermore, it provides a stable and credible mechanism between 2027 and 2037.

569. Costs and benefits presented in this Impact Assessment assume that the RO continues to be set through headroom until 2037, and does not assume a change at 2027 to a fixed ROC. However, we would predict that the impact on the overall level of costs and benefits from moving to a fixed ROC post 2027 are likely to be small, since it will apply to a diminishing number of RO recipients. There would be small benefits relating to reduced administration costs of setting the Obligation and removing any risk of a ROC price crash, but costs relating to the reform of the RO.

Grandfathering Technologies

570. Our preferred option is to grandfather all technologies currently grandfathered under the RO at the level they are receiving on 31 March 2017. Technologies which are not grandfathered under the RO at that time (currently bioliquids and co-firing biomass are not grandfathered) will be grandfathered at the level applying on 31 March 2017. It is still under consideration whether any uplifts not covered by the grandfathering policy (currently the CHP uplift and energy crop uplift) should be grandfathered in a similar way. This option provides certainty for investors and reduces administration costs as there won't be a need to hold ongoing Banding Reviews or emergency reviews. Grandfathering all technologies (including fuelled technologies) however puts the fuel cost risk on generators, i.e. an increase in the fuel cost might leave generators exposed to too high costs, while a decline in fuel cost might cause rent payments to generators.

571. Costs and benefits of grandfathering certain technologies will be covered as part of the forthcoming banding review Impact Assessment.

Phasing

572. The ROO 2011 allows generators of offshore wind stations to phase their RO support, with each phase being eligible for up to 20 years support. Our chosen option implies that offshore wind projects can either register their entire site on or before 31 March 2017 under the RO (and then have an incentive to bring the turbines into operation as soon as possible, given that the RO ends in 2037) or sign a FiT CfD contract for any remaining turbines that are not registered under the RO by 31 March 2017. The lifetime of the RO will not be extended beyond the current 2037 end date. Under our provisions for grace periods, flexibility is provided for generators who, due to certain unplanned delays beyond their control in gaining their grid connection, may miss the cut-off date for accrediting under the RO.

573. The benefit of this option is that it reduces the likelihood of increasing generation in a closed RO system and therefore makes the administration of the closed RO, and the setting of the obligation level less complex. This option will increase the likelihood that projects will exercise the right to phase, but the impact on costs and benefits relative to the continuation of the current RO scheme depend on the relative incentives to renewable technologies over the period, determined by RO bandings and future decisions on FiT CfDs. There could also be additional administration burden of dealing with projects that are supported by two separate schemes.

Additional Capacity

574. In line with the closure of the RO to new accreditations, additional capacity will not be able to continue to accredit under the RO after 31 March 2017. We are minded that support post this date will be given under the FiT CfD (for additional capacity greater than 5MW, or smaller than 5MW but not eligible for small-scale FITs), or under the small-scale FIT (if smaller than 5MW and eligible for FITs).

575. Costs and benefits of this chosen option relative to the continuation of the current RO scheme depend on the relative incentives to renewable technologies over the period, determined by RO bandings and future decisions on FiT CfDs..

Annex C : Devolution

576. The UK Government and the Devolved Administrations share the aspiration to deliver a low-carbon electricity sector. The Government recognises the importance of devolution in the United Kingdom and is concerned to ensure the proper functioning of devolved arrangements. Successful delivery will come through the different Governments working together towards a set of shared goals. It will therefore be important to consider how the reforms will work across the UK. We have already been discussing the proposals with the Northern Ireland, Scottish and Welsh Governments and we will continue to work closely with them to consider how the proposals will work in different parts of the UK to ensure that, overall, they are effective and enduring reforms across the UK market.

Northern Ireland

577. Electricity is essentially a devolved matter in Northern Ireland. We are therefore working closely with the Northern Ireland Executive to consider the best approach for increasing low-carbon generation and improving security of supply at least cost to the consumer in Northern Ireland.

578. Our preference remains a UK wide FiT with FiT CfD, but we recognise that this will require working in partnership with the NI Executive, and that any FiT developed in NI will need to take account of the workings of the SEM. The NI Executive and the Northern Ireland Authority for Utility Regulation (NIAUR) are conducting further analysis of options, and we will engage constructively with the Executive on its preferred solution, and we will ensure that where appropriate any NI solution can work alongside the Contract for Difference in a UK-wide context.

579. If Northern Ireland does not enter the new mechanism, but continues use of the NIRO, or adopts a different mechanism, this may impact slightly on delivery of the UK renewable electricity target if the NI Executive has to consequently reduce its own existing target for affordability reasons. There could also effectively be competition between the mechanisms within the UK and issues to resolve concerning which consumers (Scottish, Northern Irish, English and Welsh) bear the cost of renewable deployment.

580. The SEM market already includes a Capacity Payment mechanism. As such the UK Government and the NI Executive have agreed that any Capacity Payment mechanism proposed in the EMR will apply across GB only.

581. The Government is keen that the framework of the EPS should, as far as possible, cover the whole of the UK. The NI Executive has said that it would, in principle, consider participating in a UK wide EPS regime. We will continue working closely with the NI Executive to achieve this.

Scotland

582. Scottish Ministers have been given executively devolved powers in respect of the Renewables Obligation in Scotland and we have been working closely with the Scottish Government on transitional arrangements.

583. We will continue to involve the Scottish Government in further work on institutions and in the design of the FiT CfD. The working assumption is that Scotland will be part of the new FIT mechanism.

584. The Scottish Government is supportive in principle of a Capacity Mechanism. Further discussion will be needed to determine how the mechanism should apply in Scotland and we will work with the Scottish Government as part of more detailed design work.

585. The Scottish Government is supportive in principle of the EPS. Subject to more detailed planning, it is likely that the Scottish Environment Protection Agency (SEPA) will be best placed to deliver the EPS in Scotland..

586. If Scottish generation was not part of the EMR reform, this could have negative impacts if different approaches are adopted across the UK, and different standards or incentives are in place in different administrations. This would make the market more complex for investors to understand. There could also effectively be competition within the UK as regards citing of new thermal plant.

Wales

587. The Welsh Government is supportive in principle of the proposals set out in the EMR consultation. It would like to see new low-carbon generation developed within Wales, and sees that EMR has the potential to support this expansion.

588. The Welsh Government is supportive in principle of the EPS. Subject to more detailed planning, it is likely that the Environment Agency will be best placed to deliver the EPS in Wales.

589. We will continue to work closely with the Welsh Government as we develop our market reform proposals, so that it has continued confidence in the operation of the GB electricity market.

590. If Welsh generation was not part of the EMR reform, this could have negative impacts if different approaches are adopted across the UK, and different standards or incentives are in place in different administrations. This would make the market more complex for investors to understand. There could also effectively be competition within the UK as regards citing of new thermal plant.

Annex D: Security of Supply and System Balancing

591. The electricity 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.

592. However, electricity cannot be easily stored, so to ensure a secure supply of electricity the amount being produced (supply of generation) and the amount being consumed (demand for generation) must match at all times. That is, the system must balance.

593. Electricity is traded in 30 minute periods. 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 charge[77] if they generate/consume a different amount to that they contracted for.

594. After gate closure the responsibility for ensuring supply equals demand on a second-by-second basis is held by a central body (the System Operator, currently National Grid).

595. Generators only receive revenue from the electricity they generate (other than balancing services revenue). However, as long as the price (in particular the cash-out price given that this filters out along the forward curve) is sufficient this should enable them to cover both their variable running and fixed capital costs. The next section explains this in more detail.

How an energy-only market remunerates capacity

596. While we have an electricity price that is set through bilateral contracting, the price is conceptually equivalent to a system in which everyone bids into a central pool. This model is used below to explain how an energy-only market remunerates capacity.

597. In a competitive market all electricity generators will bid at their short run marginal cost (SRMC)[78]. The electricity price is then set by the marginal cost of the marginal plant required to meet demand. All generators receive this price and the difference between their SRMC and the electricity price (the infra-marginal rent) contribute towards their capital costs.

598. When all the generation is running (in a scarcity period) the last plant will have market power and can charge more than his SRMC (up to the value placed on avoiding lost load) and will entirely cover their capital costs through these ‘scarcity rents’. All available generators receive these scarcity rents, and these are important for all generators to fully cover their capital costs.

599. In any perfectly functioning energy-only electricity market at times of short supply electricity prices rise high enough so that, overall, they cover the total costs of all resources needed to meet an economically optimal level[79] of security of supply[80]. At the economically optimal level,

[77] It should be noted that cash-out charges reflect market prices for those whose imbalance helps the system and the costs incurred by the SO in taking energy balancing actions (which generally results in a price which is less favourable than the market price) where it exacerbates the system imbalance.

[78] Strictly speaking NETA is pay-as-bid so all generators that might be called, either for energy or system reasons, offer at what they estimate the marginal offer will be. Responsive demand offers in a similar manner. However the cost of the marginal plant (plant with highest accepted offer price and conceptually in line with its short run marginal cost in a competitive market) still sets the price even though this might be muted in practice.

[79] We say level, but as there are a range of customer preferences, the reality is more like an optimal range.

[80] This is the case in any market, including those based entirely on high capital, low opex capacity since older less efficient plants are generally price setting and marginal plant at periods of high demand.

the marginal cost of supplying more security is equal to the value that consumers place on that increase.

600. Further, a perfect market should also incentivise the most economic mix of generation types.

How an energy-only market remunerates an efficient capacity mix

601. Because demand varies significantly throughout the day and year, even a perfectly efficient system will have significant amounts of plant that is only used for a small part of the time (has a low load-factor) that is needed at peak times (this is currently tea-time on working days in winter).

602. To date, GB generation has been a mixture of base-load generation (with high capital costs, but low short run marginal costs) that runs most of the time, mid-merit (e.g. CCGT gas) with lower capital but higher marginal costs that runs some of the time and peaking plant (e.g. old plant or OCGT) that has low (or sunk) capital costs but high marginal costs and runs for a small fraction of the year. A mixture of these types of plants (along with energy efficiency and demand response) is the most efficient way for supply to meet demand at all times.

603. When significant amounts of low-carbon generation come onto the system, the efficient mix of generation types (base-load/peaking) will change and the shape of the electricity price curve will change.

604. Renewable and nuclear generation have high capital costs and low short run marginal costs. However, it will not be efficient to use this to cover all demand (this would mean significant amounts of high capital cost generation doing nothing). Rather the system will continue to need low capital cost, high marginal cost plant to ensure the system balances. However, this will be squeezed into fewer running hours by the low marginal cost plant and so will need to be more dependent on higher peak prices.

Annex E: Redpoint Modelling Approach

605. Details of the Redpoint model of the electricity market can be found in the Redpoint report which accompanied the EMR consultation document[81]. The modelling approach for the two Capacity Mechanisms follows is described below, follows by a description of changes in assumptions and policy developments taken into account in this modelling which was not done in the EMR consultation stage modelling.

Modelling Assumptions

606. A range of assumptions had to me made for the effects of the different policy instruments to be modelled. The most crucial assumptions are set out below, for a complete discussion please see the Redpoint report[82].

607. All options, including the baseline, were set to achieve the same level of decarbonisation and level of renewables deployment in order to make them comparable.

608. **Decarbonisation:** the indicative target used is 100g CO_2/kWh in 2030, which is the level that would be reached if investors had perfect foresight of DECC's published long-term carbon price. This provides a reasonable goal against which to test the options for reform, since the DECC carbon values are representative of a least cost path to global decarbonisation.

609. This is similar to the figure previously recommended by the Committee for Climate Change, although a more recent publication recommends a lower figure of 50g/kWh.

610. **Renewables uptake:** Consistent with the lead scenario of the Renewable Energy Strategy, it is assumed that 29% of total electricity generation comes from renewables in 2020.

611. This number rises to 35% by 2030 in accordance with the level that would be reached if investors had perfect foresight of the target-consistent carbon price, which reaches £70/t in 2030.

612. **Carbon prices:** Budget 2011 announced Carbon Price Floor as policy from 2013, and hence this is now included in the baseline rather than as a policy as in the work undertaken for the Consultation Document. In accordance with Budget, the carbon price is set to £16/tCO_2 in 2013 rising on a linear trajectory to £30/tCO_2 in 2020.

613. **Fuel prices:** fuel price assumptions are based on DECC's Updated Energy Projections (UE) June 2010 Central Price case.

614. **Demand:** demand assumptions are based on the UEP June 2010 Central scenario for total electricity supply.

615. **Capital costs**: Capital cost assumptions for new build generation have been taken from the Mott MacDonald UK Electricity Generation Costs Update report, June 2010[83].

616. **Hurdle rates**: Hurdle rates are based on Redpoint assumptions, informed by market data points where possible. We assume hurdle rates are higher for less mature technologies. Hurdle rate sensitivities come from an assessment by Cambridge Economic Policy Associates.

---

[81] Available on DECC's website at http://www.decc.gov.uk/en/content/cms/consultations/emr/emr.aspx
[82] Redpoint WP report reference
[83] http://www.decc.gov.uk/assets/decc/statistics/projections/71-uk-electricity-generation-costs-update-.pdf

617. **Investor foresight**: Investor foresight of the carbon price is assumed to be 5 years, in line with the assumptions made in the Carbon Price Floor consultation. There is no assumed foresight of wholesale prices (outside of aforementioned carbon price).

	Investor Foresight
Carbon price	5 years
Wholesale price	None
Support level	Duration of the contract

618. **Transition/timing:** Policies are assumed to be implemented in 2014 with two years' notice.

Limitations of the modelling

619. There are important limitations to the modelling, the key ones being:

- It does not account for the administrative costs associated with both the transition to the new market arrangements and the operation thereafter.
- The modelling assumes that policy change would lead to no short-term change in investment behaviour; in practice, there is likely to be some hiatus, particularly under the FiT CfD option.
- The modelling assumed that payments were made based on availability rather than output, in order to reduce the distortionary impacts of negative pricing that result from output-based payments.
- The model does not account for any longer-term link between fossil fuel prices and the carbon price, nor does it account for any impact of changes in low-carbon investment in the UK on the carbon price (i.e. the carbon price is exogenous). If the proposed measures bring forward investment in low-carbon generation in the UK that would not have been incentivised by just the carbon price it is likely to lead to a decline in this carbon price.

Strategic Reserve

620. The key parameters for the Strategic Reserve option are:

- As described in the text, a central body forecasts the need for additional capacity accurately and tenders for some general capacity (that is met from existing coal and CCGT plant) and some responsive capacity that is provided by OCGTs. For some generators this would require a change of IED decision from Limited Lifetime Opt-out (LLO) to Transitional National Plan.
- The gap between the forecast de-rated capacity margin and the targeted 10% that develops in the early 2020s is assumed to be filled by a range of generation technologies.
- The tendered capacity mix is one of multiple combinations of new and existing plant which would fulfil the requirements.
- The role of new DSR is not captured in the modelling, but would have the potential to lower costs to consumers if it participated as has been shown by experience in the USA, for example.
- It is assumed tendered capacity does not affect the wholesale market or weaken investment signals for non-tendered capacity. It is therefore a form of last resort strategic reserve.

Reliability Market

621. To capture the effect of reliability contracts, both the contract allocation process (auction) and the effect on the wholesale electricity market have been modelled.

622. The auction process is modelled by a 'stack' of the capacity offered into the auction. For simplicity we have assumed that all existing and potential new generators are bidding in their de-rated capacity to the auction. In reality, however, we recognise that some generators (such

as wind plant) may decide not to participate in the auction process, or to only offer a percentage of their de-rated capacity.

623. The bid prices for each generator are calculated based on the required additional revenue to extend the plant lifetime or build a new plant.

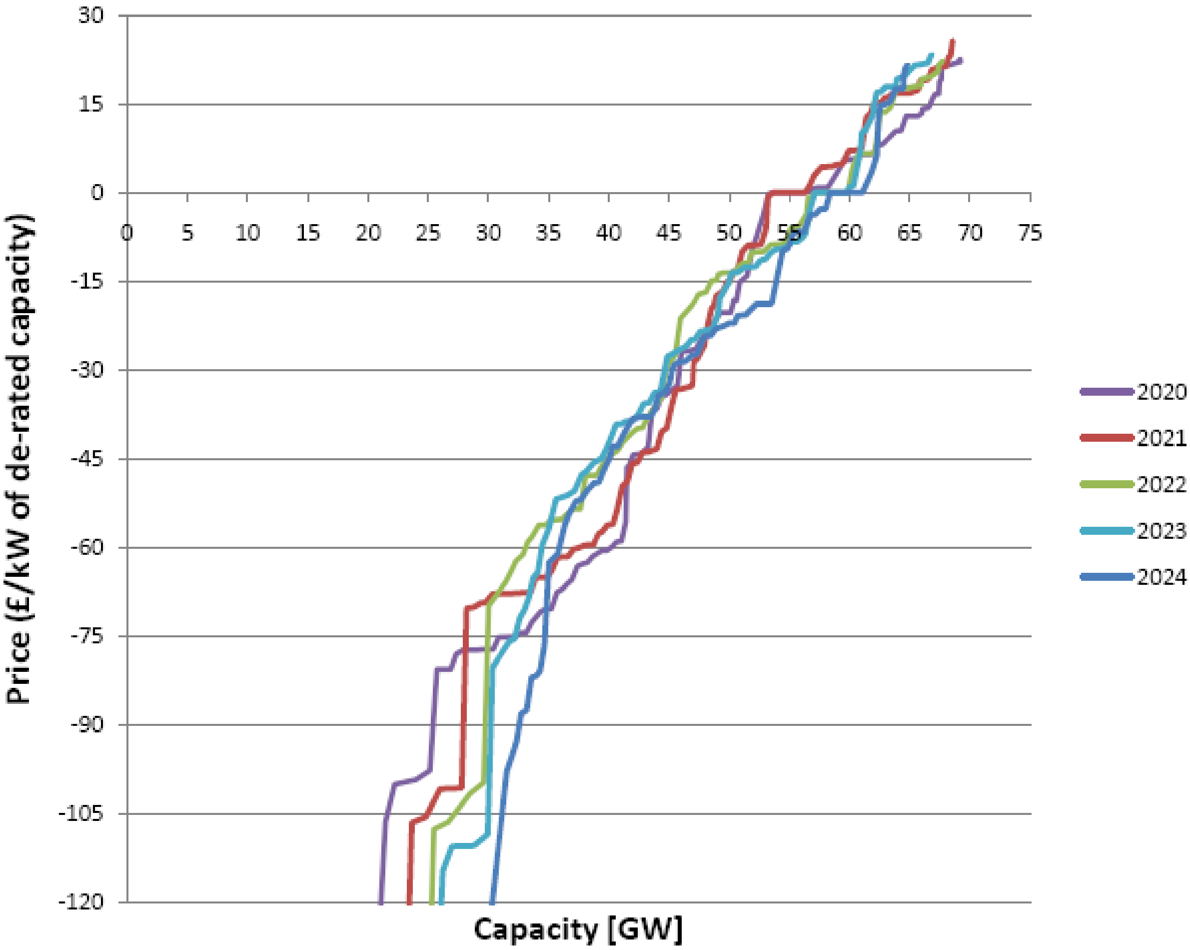
624. In each year, the auction ‘stack’ requires as inputs the volumes of capacity offered by each generator or new project and the prices at which this capacity is offered. Each generator offers at a price which makes their generation or project profitable, de-rated by the standard capacity credits in the EMR modelling. From this ‘stack’, the auction clearing price for each year is calculated, along with which plant receive the reliability contracts.

625. The offer prices are calculated as follows:

- Offer price for existing generators (£/kW) = (expected wholesale market revenue –expected generation costs –annual fixed costs) / De-rated Capacity
- Offer price for new generators (£/kW) = (expected wholesale market revenue –expected generation costs –annual fixed costs –annuitised capital costs) / De-rated Capacity

626. Some examples of the auction stack for different years are shown in Figure 6. A negative price denotes generators that are expecting to be profitable even without revenues from RCs; we assume that these generators are bidding in at zero. A positive price denotes generators that are expecting to be making a loss based on their expectations of wholesale electricity market revenues and thus require additional revenue streams in order to stay open or to be built.

Figure 30: An example of "the stack" used to calculated the auction clearing price of a Reliability Market.



627. The key parameters for the Reliability Market are :

- The volume of contracts bought by the central buyer are peak demand + 10%. This is open to all capacity and there is no differentiation based on flexibility.
- Contract length: 1 year contracts for existing plant and 10 year contracts for new plant.
- Once a generator has physically closed it cannot re-enter the auction in a later year –i.e. the possibility of mothballing capacity has not been considered.
- Generators use the same de-rating factors as the central buyer.
- Investors have full confidence that the policy will maintain de-rated capacity margins at a minimum of 10%.
- Pumped storage hydro plant and interconnectors bid at zero (price-takers).
- Plant that have signed a multi-year reliability contract bid in at zero, while they are being paid the contracted level.
- All plant operating under the Limited Lifetime Opt-out (LLO) mechanism must close in 2023.
- Wholesale electricity market prices never exceed the strike price.
- A reduction in hurdle rates for new CCGT and OCGT generators that receive a reliability contract.
- No change to FiT CfD tariffs, but assumed no increase in build capacity despite higher earnings. For premium payments, tariffs were increased to account for lower wholesale price but the additional RC revenue was not taken into account.

Updated baseline assumptions

628. The updated Repoint modelling for the EMR White Paper reflects policy developments and updates to DECC's assumptions around some electricity generation technologies. Specifically, the announced Carbon Price Floor (CPF) policy has now been included in the updated baseline and the following changes have been made to assumptions around renewables technologies:

- **Hurdle rates:** we have taken a percentage point off the R3 offshore wind and regular biomass hurdle rates up to 2019 and 2016 respectively;
- **Large biomass CHP steam revenues**: we have input capex, opex, fuel and carbon costs assumptions for equivalent generation of heat from a gas boiler into the biomass CHP estimates;
- **Biomass assumptions**: we have incorporated the new biomass availability and price assumptions, based on AEA (2011)[84] that the "Levy Control Framework" team have provided us with. Biomass prices have now considerably increased and this is a major driver towards the increased generation costs that you will notice in the CBA;
- We have restricted annual co-firing TWh output to a maximum of 5TWh, reflecting current levels being well below the co-firing cap.
- We have corrected treatment of micro-generation.
- We have significantly banded up marine energy in order to get some contribution by 2020. This may be regarded as a proxy for potential grant support for marine energy.
- Renewables Obligation (RO) banding approach:
  - include a separate R3 offshore wind banding;
  - smooth out banding increases in 2013 and banding decreases in 2017. For example, ROC support for onshore wind is now 1ROC/MWh between 2013-2022 and 0.25ROCs/MWh between 2023-2030, for offshore R1/R2 wind 2.2ROCs/MWh between 2013-2022 and 1ROC/MWh between 2023-2030 and for offshore R3 wind 2.7ROCs/MWh between 2013-2022 and 1.5ROC/MWh between 2023-2030.
  - switching the RO basis from banding according to financial close to banding according to first generation base

629. These changes in baseline assumptions lead to changes in the relative economics of the different generation technologies, which have not been fully counteracted by changes in the RO banding assumptions. The overall result is that the updated baseline is around £10bn worse in net welfare terms (NPV 2010-2030, real 2009) compared to the old EMR consultation document baseline scenario. This in turns means that all EMR package options now look to be an improvement in net welfare terms compared to the update baseline, as discussed in paragraph 449 on page 104.

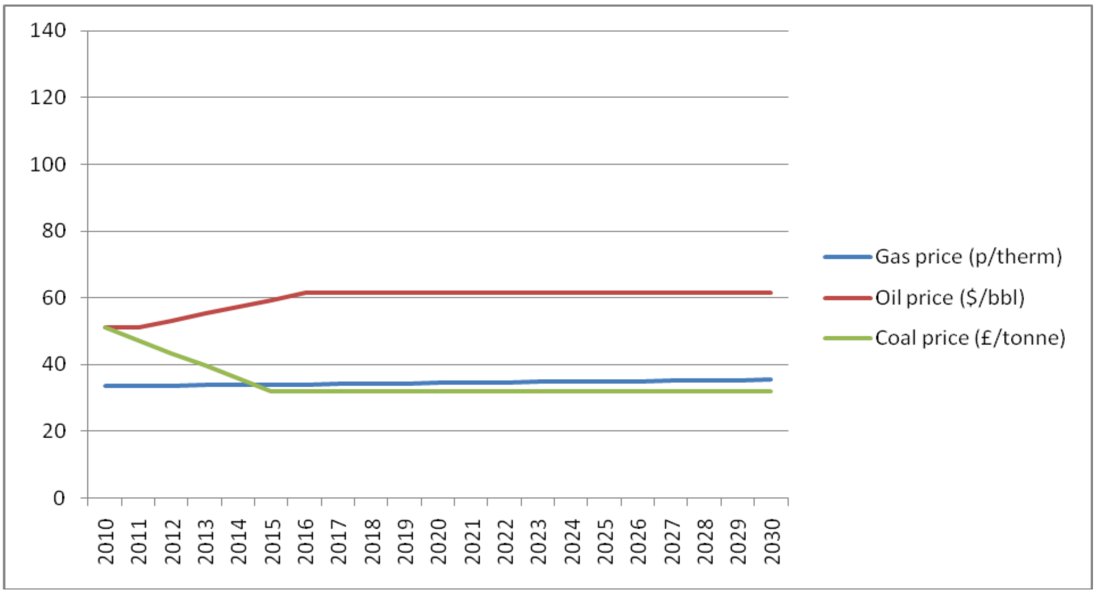
630. The differences between the original and updated EMR baseline scenarios are due to differences in new build generation capacity as well as dispatch decisions. The updated baseline has a more rapid decarbonisation trajectory than the old baseline, and there are therefore savings in carbon costs. This saving in carbon costs is, however, outweighed by much higher generation costs (largely due to higher cost of biomass fuel costs- due to changed assumption above) and capital costs (largely due to more R3 offshore wind build and more small scale and CHP biomass – due to changed assumptions of these technologies above) in the updated scenario relative to the old baseline.

[84] AEA (2011), *UK and Global Bioenergy Resource: Final Report*

Fossil fuel price assumptions used in the modelling

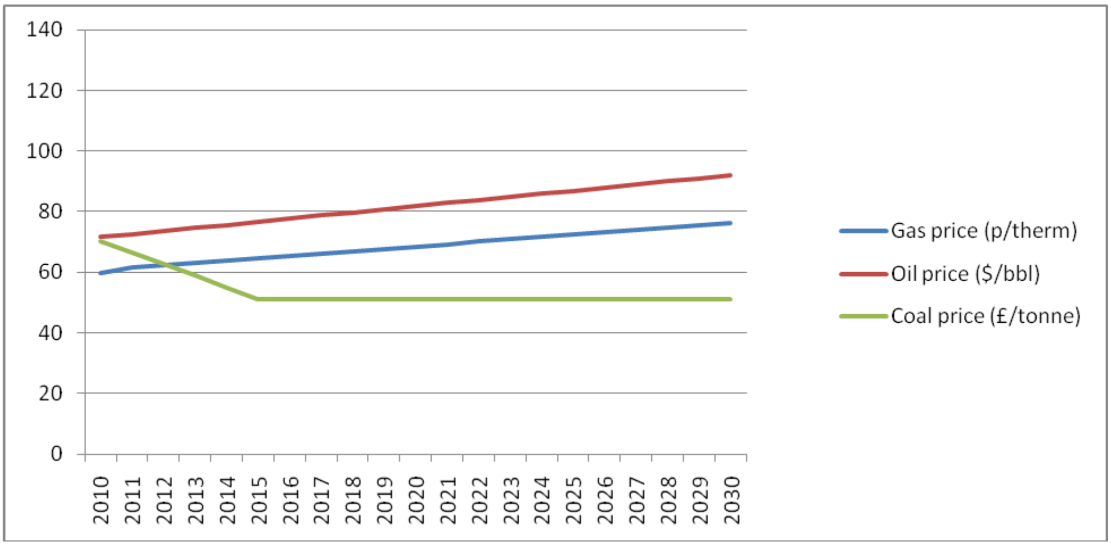
631. The charts below show the trajectories of fossil fuel prices under DECC's low, central and high price assumptions. All figures are in real 2009 prices.

Figure 31 Low fossil fuel price assumptions



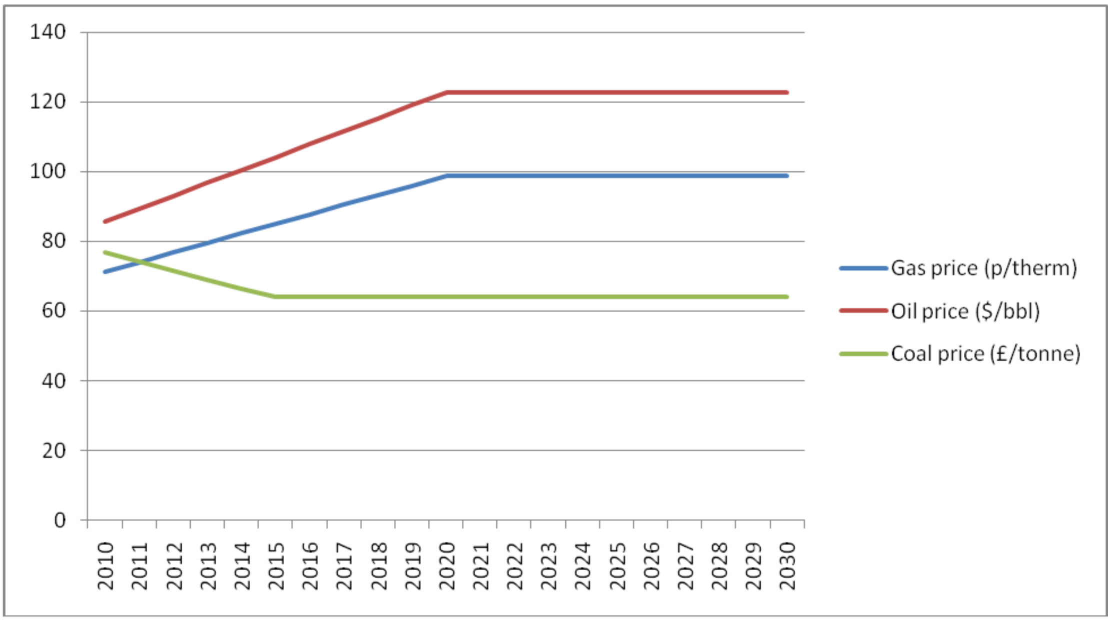
Source: DECC

Figure 32 Central fossil fuel price assumptions



Source: DECC

Figure 33 High fossil fuel price assumptions



Source: DECC

Annex F: Impacts on Business

632. Businesses will be affected in two ways by the EMR options. The first is the direct costs associated with the options and the second is the administrative burden of implementing the option.

633. The direct costs and benefits imposed by the options are those that accrue to ordinary businesses which consume electricity on the one hand, and those that accrue to electricity generation companies on the other. These costs and benefits can be estimated using distributional outputs from the Redpoint modelling in conjunction with an assessment of the administrative and institutional costs imposed on businesses.

634. Figure 34 shows the distributional impacts of EMR packages on consumers and producers. It is estimated that around 60% of electricity consumption is by non-domestic users[85].

Figure 34: Distributional analysis of packages

NPV £m	FiT CfD & SR	FiT CfD & RM	Premium FiT & SR	Premium FiT & RM
Change in Wholesale Price	-3,926	20,877	-3,139	12,067
Change in low-carbon support	11,788	3,930	2,402	-4,979
Capacity Payments	-1,183	-13,101	-1,033	-16,799
Unserved Energy	120	146	119	126
Demand Side response	-37	22	-25	16
Change in Consumer Surplus	6,762	11,874	-1,677	-9,569
Change in Wholesale Price	3,926	-20,877	3,139	-12,067
Change in Low-carbon support	-11,540	-3,684	-2,152	5,301
Capacity payments	1,183	13,101	1,033	16,799
Change in producer costs	10,642	10,405	7,919	8,586
Change in Producer Surplus	4,211	-1,055	9,939	18,619

Total GB Electricity Consumption	290,075	290,075	290,075	290,075

85 DECC statistics - http://decc.gov.uk/en/content/cms/statistics/regional/electricity/electricity.aspx

(GWh) Commercial and Industrial Consumption (GWh) Proportion of electricity that is business (=290/178)	178,085 61%	178,085 61%	178,085 61%	178,805 61%
Benefit to Business =(CS*%Business +PS)	8,336	6,118	8,917	12,781
Less: Admin costs on business (FIT CFD+CM)	6-36	11-72	6-36	11-72
Less: Institutional costs on private business (if applicable)	29-161	29-161	29-161	29-161

Overall net benefit range to business	8,139 - 8,330	5,885 - 6,107	8,720 - 8,911	12,548 - 12,770
on EAB basis	553 -566	400-415	592-606	853-868

635. *FiT CFD package:* Depending on the choice of Capacity Mechanism, the total costs to businesses of this option are between 15bn for FIT CFD with SR to £33bn for FiT CFD with RM or £1bn-2.2bn per year on an equivalised annual basis (EAB)[86]. These costs arise primarily from business consumers paying higher wholesale prices and capacity payments, whilst electricity generating businesses receiving less rent from all consumers due to lower levels of payments under FiT CFDs and SR than in the baseline. Whilst with FiT CFD and RM the only difference is all consumers pay lower wholesale prices and lower low-carbon payments which is only partly offset by lower generation costs and capacity payments to generators/producers than in the baseline.

636. The total benefits to business, again depending on the choice of Capacity Mechanism, would be between £23bn for FiT CFD with SR to £39bn for FiT CFD with RM or £1.6bn-2.6bn per year on EAB. In the case of FiT CFD with SR this arises from generators/producers receiving higher wholesale prices from domestic consumers and also capacity payments from them, whilst

[86] Where figures are presented in EAB a 20 year policy assessment period has been used.

experiencing lower generation costs (by having more renewables generation which are low marginal cost plant) than in the baseline. In addition business consumers pay lower payments under FiT CFDs with SR and also benefit from greater electricity security of supply (due to less energy unserved) than in the baseline. In the case of FiT CFD with RM the only difference is that all consumers pay lower wholesale prices and lower low-carbon payments, which is only partly offset by lower generation costs and capacity payments to generators/producers than in the baseline.

637. Taking into consideration the administrative and institutional costs to business (discussed in main IA sections). The overall net impact on business would therefore be a benefit of between £5.8bn - £8.3bn or £0.4bn-0.6bn per year on an EAB depending on the choice of Capacity Mechanism.

638. *Premium FiT package:* Depending on the choice of Capacity Mechanism, the total costs to businesses of this option are between £5bn with PFiT with SR to £25bn for a PFIT with RM or £0.3bn-1.7bn per year on EAB. In the case of PFiT with SR these costs arise primarily from business consumers paying higher wholesale prices and capacity payments, whilst electricity generating businesses receiving less rent from all consumers due to lower levels of payments under PFIT and SR than in the baseline. Whilst with PFiT and RM all consumers pay lower wholesale prices but these are more than offset by capacity payments, greater low-carbon support payments and lower generation costs to generators/producers than in the baseline.

639. The benefits to business, depending on the choice of Capacity Mechanism, would be between £14bn for a PFiT with SR to £38bn for a PFiT with RM or £0.9bn-2.6bn per year on EAB. In the case of PFiT with SR This arises from generators/producers receiving higher wholesale prices from domestic consumers and also capacity payments from them, whilst experiencing lower generation costs (by having more renewables generation which are low marginal cost plant) than in the baseline. In addition business consumers pay lower payments under PFiT and SR and also benefit from greater electricity security of supply (due to less energy unserved) than in the baseline. In the case of PFiT with RM the only differences are that wholesale prices are lower for all consumers but these are more than offset by the capacity payments, greater low-carbon support payments and lower generation costs to generators/producers than in the baseline.

640. Taking into consideration the administrative and institutional costs to business (discussed in main IA sections). The overall net impact on business would therefore be a benefit of between £8.7bn – £12.7bn or £0.59bn – 0.9bn per year on an EAB depending on the choice of Capacity Mechanism.

Annex G: Other wholesale market initiatives

641. In addition to the EMR proposals, there are a number of other important developments which have the potential to affect the future wholesale electricity market. These initiatives will all impact upon the wholesale market in their own right and may also have important interactions with the EMR proposals. This section summarises developments in three areas:

- cash-out review;
- liquidity; and
- market coupling

Cashout review

642. Ofgem's cashout review promises revisions to the electricity imbalance pricing regime, which has the potential to change the incentives upon parties to balance their physical and contractual positions. Options being considered include:

- putting a price on currently non-costed SO actions;
- more effective allocation of reserve contract costs;
- change to more marginal pricing; and
- change to a single cash out price.

Liquidity review

643. Ofgem has recently announced its proposals for improving wholesale electricity market liquidity (following on from its consultation in February 2010[87]). The proposals include two measures:

- a month-ahead auction process in which the 'big 6' have to offer for sale generation which equates to 10 to 20% of their retail supply volumes.
- mandatory market maker arrangements under which the 'big 6' have to make offers to trade defined products at a reasonable bid-offer spread and in reasonable clip sizes.

644. Other options not taken forward from the consultation document included:

- an obligation to trade directly with small/independent suppliers as a licence condition placed on large generators; and
- introduction of a self-supply restriction on vertically integrated companies.

Market integration

645. Over the past year, the European debate on market coupling has placed a much stronger emphasis on day-ahead *market coupling*[88]. This forms part of the target model for market integration as set out in the draft final Framework Guidelines on Capacity Allocation and Congestion Management (CACM) [89] issued by the Agency for Cooperation of Energy Regulators.

---

[87] 'Liquidity Proposals for the GB wholesale electricity market', Ofgem consultation paper, 22 February 2010.

[88] Market coupling is an approach used to allocate capacity on interconnectors. It links interconnected wholesale energy markets with an implicit auction that determines efficient cross-border flows according to price differential between markets.

[89] On 11 April 2911, the Agency for the Cooperation of Energy Regulators (ACER) launched a public consultation entitled "Framework Guidelines on Capacity Allocation and Congestion Management for Electricity".

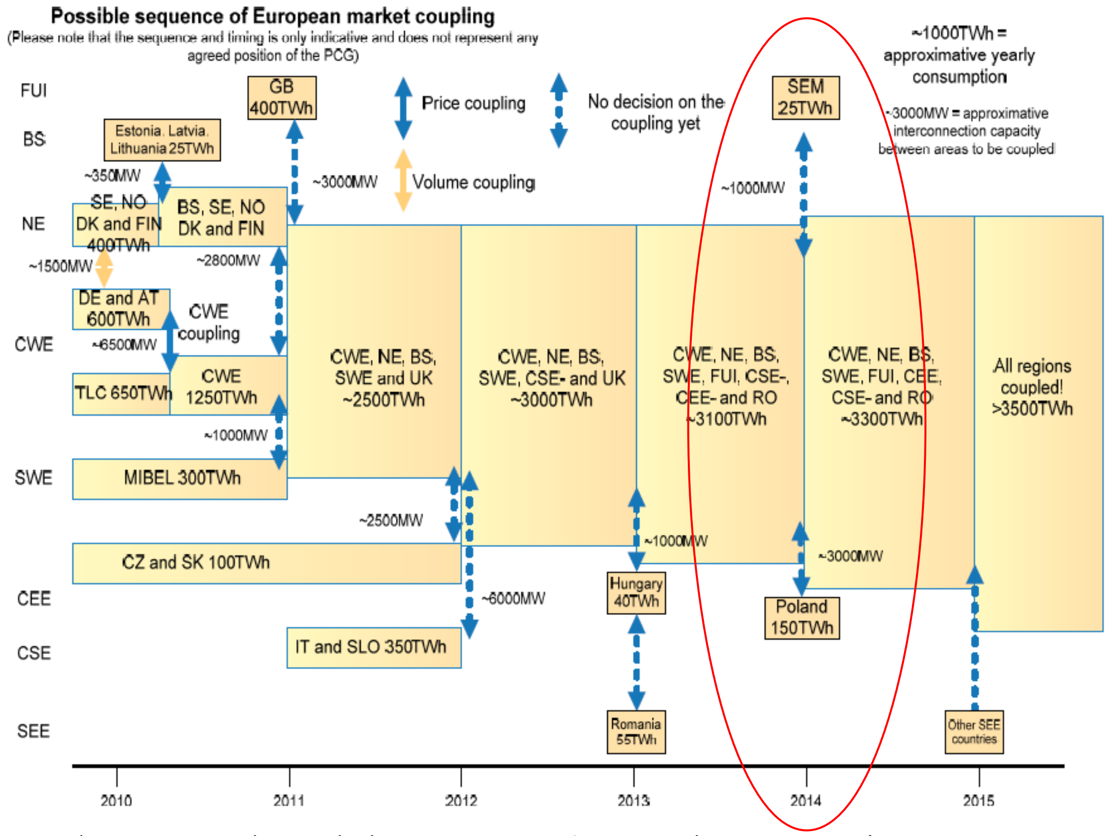
646. These will inform legally binding network codes that will be developed by ENTSO-E over the next two to three years. A network code will be developed for each of the four objectives set out in the Framework Guidelines:

- 'to ensure optimal use of transmission network capacity in a coordinated way' (through appropriate mechanisms for capacity calculation and definition of zones);
- 'to achieve reliable prices and liquidity in the day-ahead capacity allocation';
- 'to achieve efficient forward market'; and
- 'to design efficient intraday market capacity allocation'.

647. The drafting on the CACM network codes will start in Q4 2011 and the provisions of this network code would need to be implemented by 2014, as noted in the April 2011 Agency for the Cooperation of Energy Regulation consultation.

648. The day-ahead requirements are centred on the delivery of day-ahead price coupling across Europe, building on the target model for market integration. Figure 35 illustrates the expected timeline for the development of day-ahead price coupling under the target model. Under this timeline, day-ahead price coupling is expected to be implemented across all EU markets by the end of 2015[90].

Figure 35 – Intended sequence for EU market coupling



Source: 'PCG Report to the XVIIth Florence Forum, 10&11 December 2009, Rome'

90 On 4 February 2011, there was a European Council (Heads of Government meeting) discussion about energy issues. This called for the completion of the single market for electricity by 2014 (a year ahead of the Commission target).

649. There are also two industry-led initiatives to deliver day-ahead price coupling by the end of 2012 that would cover BETTA. The development of more integrated European markets will be of increasing importance to GB as we expect an expansion of interconnection in the coming years.

650. Currently, there is 3GW interconnection between GB and NW Europe[91] (i.e. France and the Netherlands), and 0.9GW of interconnection between GB and the SEM (including the East West Interconnector scheduled to come on line in 2012).

651. In addition, there are a number of projects currently at the planning stage[92]:

- 0.7GW interconnection with the SEM (Imera);
- 0.8GW interconnection with France (Imera); and
- 1.0GW interconnection with Belgium (National Grid and Elia).

652. Projects that are currently at an earlier stage of development would increase interconnection with North West Europe by a further 2.0GW. There is also a proposal for the development of a 1.0GW link with Norway.

653. If all of these projects were realised, interconnection capacity would be:

- 6.8GW with NW Europe;
- 1.6GW with SEM; and
- 1.0GW with Norway.

654. Ofgem's view is that total interconnection capacity could be 8GW by 2020 [93].

91 This includes the BritNed interconnector between GB and the Netherlands.

92 'Electricity interconnector policy', Ofgem, January 2010.

93 Ibid.

Annex H: Level Setting

Options for price discovery

655. The Government has identified four options for setting the strike price.

(a) Auctions

656. In the consultation document Government expressed a preference for using auctions as a price discovery mechanism due to their competitive price discovery characteristics.

657. Among the benefits we expect could be realised from an auction process are:

- that they are competitive so reducing the need for Government to understand companies' costs in detail as these are exposed through the bidding process;
- that they 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.
- Support levels can be adjusted to cost improvements over time as each round of auctions takes place and bidders reveal cost improvements.
- They can be tailored for technology and can be time period neutral, or technology, or site specific.

658. The success of an auction mechanism will be extremely sensitive to its design, as well as when it is introduced. In order for it to work effectively it will be necessary to ensure that there are enough participants to drive competitive price discovery and that the auctioneer understands technology costs well enough to negate the risk of optimism bias or winner's curse where bidders may bid overly aggressively and later find that the support level they secured is too low for construction to proceed – a major criticism of the NFFO arrangements.

(b) Tenders

659. Tenders are a form of truncated auction where participants only have one opportunity to submit a bid to the procuring body, with no opportunity to update that bid in the light of subsequent information disclosure by other participants. They are thus less effective for competitive price discovery, but they can be expected to work most effectively where values are well established or there is little to be gained through price discovery. It may prove a possible mechanism where there is a limited field of participants or projects which means an auction would not be viable, or as a precursor to a negotiated settlement.

660. The principal requirement for a competitive price setting process such as an auction or tender is the ability to ration and ensure efficient price discovery by having both winners and losers in any process.

(c) Administrative Setting: Banding Review

661. Another option is a banding review such as used for setting the Renewables Obligation support levels. DECC has experience of setting the RO Bands through this mechanism and the methodology was developed in consultation with industry and is understood and accepted by them. The effectiveness of it for price discovery is subject to generators, equipment suppliers and potential developers transparently exposing their costs to consultants and then potentially the market at large and has been criticised due to concerns that it has been captured by the industry in the past. Moreover, as the market is mobile and reflects inputs from number of external factors such as foreign exchange costs prices may prove out of date in very short time.

Work to understand some of these limitations and build on the experience of the RO Banding Review process is ongoing.

(d) Administrative Setting: Negotiated Settlement

662. Negotiated Settlement may be appropriate where there is a limited field of developers or the technology is new and costs are not well understood. It may be particularly suited for setting the price for nuclear. A risk is that HMG would be explicitly determining the technology mix.

5.4.5.ii Government's preferred option

663. Government's favoured option remains a more competitive price setting mechanism such as an auction or tender.

664. Recognising that this will require a degree of rationing to be present we believe that it will be necessary to set conditions for its introduction and to put in place a staged move via an administrative band setting process with negotiated settlement for some technologies.

665. Determining when rationing will be possible is dependent on improvements in investors' project development capacity and financing envelopes, as well as HMG's policy aspirations for the delivery of specific technology targets e.g. for the purpose of achieving diversity of generation or for encouraging innovative technologies or to meet EU renewables objectives.

666. We believe the decision to move to an auction/tender process should depend on meeting the following tests, e.g. that:

667. there is more development capacity than needed in any given year/period so the auction can identify winners and losers, e.g. we no longer need all generation for the purpose of meeting targets such as the EU Renewables Target.

668. participants are incentivised to bid efficiently such that they are competing on an equal footing (i.e. each individual bidder has an equal probability of winning).

669. participants bids are [directly] comparable, e.g. that the projects bidding are at similar points in the development process so prices are reasonably certain, and that the characteristics of the generation being delivered is not such that any bid is unduly favoured on grounds other than price such as policy choice to favour a particular type of generation.

670. Prior to the tests being met we believe it is appropriate to continue with an administrative price setting process, building on the experience of banding the Renewables Obligation. An expectation would be that the starting price at least improves upon the current RO levels (for renewables) by the expected efficiency gain of the new system. This should allow participants in the market certainty about the process and a smooth transition to a new competitive price discovery model using a process they are familiar with from the RO. We are looking at measures to optimise the price discovery characteristics of the banding process.

5.4.5.iii Timing of the move to competitive price discovery

671. We believe that there are constraints on introducing a competitive process for renewables, nuclear and CCS in the near term. We do not believe it will be possible for renewables technologies until the investments intended to meet the Renewables Target have been made as much of this generation is due to come online between 2017 and 2020. The uncertainty and disruption arising from introduction of a competitive process is likely to undermine the delivery

of the target. This means that, allowing for the development and construction lead-times we could look to run competitive processes for renewables from 2017 onwards to support projects that would begin generating from 2020. Both nuclear and CCS currently have limited numbers of participants – CCS has not yet be demonstrated in a fully integrated manner at commercial scale for electricity generation. As such it is unlikely they would be able to participate in a competitive auction in the short term.

Annex I: FiT CfD design principles

Efficiency

5.4.5.iv P1 - LC instruments are designed to promote cost efficient low-carbon investment and not, per se, a vehicle for wider market reform

672. It is an overriding principle, that the LC instruments should be designed to deliver on their primary purpose and not be given any secondary roles as a vehicle for changing or reforming the general market and trading arrangements. It is recognised that these contracts, when issued in large quantities, have the potential to influence operational behaviour, price formation and liquidity in the wider wholesale market. Nonetheless, they should not be regarded as a (supplementary) instrument for directing or incentivising particular changes to participant behaviours and/or the operation of trading arrangements.

673. An instrument which is designed for one purpose will likely prove an inefficient and uncertain vehicle for supporting other objectives, e.g. reform of the wider market and trading arrangements. The impact of these contracts will depend on whether or not they are successful in attracting cost-effective LC investment, rather than the merit and importance of delivering on any wider reform objectives. Such objectives should therefore be delivered through direct and consistent reform of the underlying trading arrangements themselves or institutions which apply to the entire market and affect all participants (e.g. reform of cash-out and balancing arrangements[94]).

674. One important implication of this principle is the need to ensure that the LC instruments, as far as possible, are designed to avoid distorting normal market operations and natural commercial incentives for active market participation. A particular concern in this respect is the importance of avoiding dilution or dampening of price signals for efficient operation and optimisation as well as availability and reliability. Failure to satisfy these requirements could greatly increase the risk of unintended consequences as well as render subsequent market reform initiatives far less effective. Several of the design principles set out in the remainder of this section (and in particular P2 – P5) are motivated by the importance of avoiding such distortions.

5.4.5.v P2 - Recognise that commercial and operational behaviour varies across different classes of generation (no 'one-FiTs-all' solution)

675. While a FiT CfD instrument can be applied to all types of generation capacity, the specific design does need to recognise the characteristics of the plant being supported by the instrument. Any contract (or for that matter, any FIT) has the potential to influence a generator's commercial incentives and operational behaviour, which vary considerably across different types of plant.

[94] Annex G provides further details on current market initiatives in these areas.

5.4.5.vi P3 - Avoid removing normal commercial incentives for active market participation while ensuring the generator is able to achieve (hedge) the FiT CfD reference price

676. Although the FiT CfD instrument is designed to provide LC support, this does not imply removing all exposure to competitive energy markets and prices. It may be possible to design an instrument which removes most or all risk from the investor. However, such an instrument would almost certainly not represent the optimum solution from the perspective of the Government, consumers and other market participants as well as the future development of the GB energy markets. Furthermore, such a solution would likely prove inefficient in so far that investors in general will be better placed to manage and mitigate (residual) market and operational risks than the Government or consumers.

(a) Preserving incentives for market participation

677. It is therefore important to ensure that the proposed LC instrument retains normal commercial incentives for generators to remain active participants in the GB power markets. This principle is closely related to P2 above in so far that what constitutes "normal commercial incentives" vary across the different classes of generation. Intermittent generators (i.e. wind) will tend to spill into the short-term markets and will typically not (as stand-alone generators) actively participate in the forward markets. In contrast, large scale baseload and mid-merit plant will typically contract a (large) portion of their forecast generation in the forward markets. It is a design principle to ensure that the LC instrument, as far as is practically possible, avoids removing or otherwise distorting the "normal" incentives for active market participation (the incentives which exists in the absence of these contracts). In part for this reason, the proposed market reference price for intermittent generation is a short-term (prompt) index, whereas the reference for baseload generation is based on the forward markets

(b) Enabling generators to realise the MRP

678. While the LC support mechanism should not remove all risk from investors, nor should it leave or create risks which the generator has no ability to manage. For the support mechanism to function effectively, it is critical that the generator is able to realise the market reference price through hedging or direct sales in the market. Inability to achieve the market reference price creates uncertainty with respect to the total level of support provided by the FiT CfD. It is therefore a design principle that the chosen MRP for different classes of generation must reference a market:

- To which the generator readily has access; and
- In which the generator reasonably can be expected to possess the required operational and commercial capabilities.

679. Further we recognise suppliers as well as generators have forward hedging requirements and will continue to do so. Suppliers, in general, try to avoid exposure to short-term (day-ahead and within –day) prices and the volatility such markets hold. Certainty of costs so that a supplier can pass these through to consumers effectively via stable tariffs is a key component of their hedging strategies. The current market facilitates forward transactions with generators selling on a forward basis to suppliers. It is important that these LC Instruments do not impact these normal commercial incentives but allow the market (in this case buyers) to operate in a similar way to that it does at present. Whilst the generator is seeking to achieve the MRP, these contracts could direct liquidity into any market segment. The generators should be directed to

the market segment in which they would naturally operate (e.g. forward markets for baseload or prompt for intermittent). By contrast if all LC contracts directed the generator to sell into prompt markets, suppliers would be unable to purchase this power without taking some element of short-term risk which they do not at present.

5.4.5.vii P4 – Avoid dampening, diluting or otherwise distorting price signals for reliability and availability aimed at operating across the entire industry/market

680. The LC instruments are designed to promote investment, when issued in large quantities they have the potential to impact operational behaviour and therefore system security. There are at least three different system security objectives which need consideration, namely:

- Maintaining a forward capacity balance which ensures there is enough plant with the right characteristics to deliver a secure system longer term;
- Ensuring that all generation plant within the GB market have strong incentives to be available and reliable in operational timeframes; and
- Securing availability and access to sufficient Short Term Operating Reserve (STOR type) to provide system balance and other system services.

(a) Capacity Balance

681. FiT CfDs will afford Government a fairly direct means of control over future capacity balance by varying the contract quantities across LC technologies. While the renewables obligation (RO) also provides a mechanism for low-carbon investment, it does not include low-carbon baseload capacity such as nuclear. Arguably, the introduction of LC FiT CfDs therefore affords Government more direct control over a wider share of the overall capacity balance than under the existing regime. Any control over low-carbon capacity has though a direct counteracting impact on the capacity not receiving support.

(b) Availability and reliability signals

682. The existing Balancing Mechanism (BM) and intra-day markets provide short-term price signals for reliability and availability. Arguably, in the current GB market these signals are at least as strong as in other comparable markets (e.g. NordPool, the Continental power markets, the Irish SEM). It is therefore important that the LC instruments, as far as possible, are designed in such a way that they avoid removing, dampening or otherwise distorting market reliability signals. For example, if the FiT CfDs for baseload and inflexible plant removed all exposure to intra-day spot markets and the BM, the incentives for reliable operation and optimisation of maintenance planning would be severely diminished compared to the existing market. Furthermore, LC instruments which dampen or eliminate market reliability signals would potentially render reforms of the wider trading and cash-out arrangements in the GB market ineffective. It is therefore a design principle that the LC instrument does not dampen or distort reliability price signals aimed at operating across the entire industry. It is not the role of FiT CfDs to shield LC generation from such signals.

(c) Flexible Reserves

683. The majority of LC plant is, certainly initially, unlikely to be a candidate for STOR contracts. However, as the baseload segments of the wholesale market progressively becomes dominated by LC generation there will be a need to target LC investments towards flexible capacity

operating in the mid-merit and peaking segments (e.g. biomass). It is therefore important that the contracts for such mid-merit or peaking LC capacity are structured to provide the right incentive from system security - should support for LC generation still be required by this point.

5.4.5.viii P5 – Mitigate risk of distorting or damaging the liquidity and depth in the GB power market and, where possible, support positive development of liquidity

684. The award of FiT CfDs in large quantities has the potential to influence operational behaviour and therefore price formation and liquidity in the wholesale market. While these contracts require liquidity in the chosen MRP, they will also tend to direct market liquidity towards the chosen index. To ensure that it receives the intended level of support, the LC generator needs to be able to achieve the MRP. Otherwise, the generator is exposed to basis risk it cannot directly manage. Generally, companies which have a large share of LC generation within their portfolio must be expected to align their trading strategies to the index in order to avoid this basis risk.

685. It follows that the LC support mechanism has the potential to distort as well as support market liquidity depending on the chosen market reference price. For example, if all contracts were to be struck against a short-term/prompt index, it is likely that liquidity would become more focussed on these market segments. This would potentially be to the detriment of liquidity in existing forward markets which already suffer from lack of depth. In turn this might further inhibit contestability in the GB markets and limit the ability of independent suppliers and generators to operate outside of a vertically integrated corporate structure.

686. It is therefore a design principle that these contracts avoid distorting general market liquidity by over-emphasising a particular segment of the market term structure (i.e. incentivising spot to the detriment of forward markets). It is further an objective that these contracts, as far as possible, support the development of both short and longer-term liquidity in line with Ofgem's market liquidity initiatives. This is a further reason for choosing a short-term (prompt) index for intermittent generation while using a forward market reference for baseload generation.

Cost to Society

5.4.5.ix P6 - Provide for efficient allocation of risks between generators and consumers

687. The primary objective of the FiT CfD design is to provide investors with sufficient certainty and support to enable the scale of LC investment required at the least cost to society and consumers. It is therefore an overarching design principle that these contracts should provide for efficient allocation of risk between generators and consumers. This principle is course closely linked to the efficiency principles set out above (P2 to P5) and in particular to the need to ensure meaningful exposures to the wholesale and balancing markets. However, the requirement for efficient risk allocation also implies that the arrangements in general need to be tightly defined.

688. It may be possible to design an instrument which removes most or all risk from the investor. However, such an instrument would almost certainly not represent the optimum solution from the perspective of Government or consumers. Furthermore, such a solution would likely prove inefficient insofar investors in general will be better placed to manage and mitigate (residual) market and operational risks than Government or consumers. By the same token, it would be inefficient to leave risk with generators which they have little or no means of managing. This is

one reason that the proposed contract designs, while not technology specific, make clear distinctions between different classes of generation. The additional complexity that this entails is necessary to ensure that risks are allocated efficiently. Finally, protecting consumer interests requires careful consideration of how to mitigate the risk of (unintended) windfalls as well as the potential for contract gaming/manipulation. These issues are addressed in P7 and P8.

5.4.5.x P7 – Mitigate risk of potential for windfall profits and extraction of excessive rents

689. The primary objective of the LC support mechanism is to provide investors with sufficient certainty and support to enable the scale of investment in LC generation capacity necessary to deliver the Government's renewable targets and decarbonisation goals.

690. The rationale for this mechanism is to enable LC investments which otherwise would not take place, given current expectations of market prices and conditions. It is a logical consequence that the consumer, which ultimately provides the support, should be protected from potential of windfall gains and excessive rents should market conditions prove materially different to current expectations. If market prices actually rise much faster and higher than expected, LC generators could earn a total remuneration over and above what was required to justify the investment in the first place. It is a core principle that the LC instruments include a mechanism for clawing-back profits, should future market prices actually render some or all of the initial support unnecessary.

5.4.5.xi P8 - Mitigate risk of gaming and contract manipulation to prevent enhanced profits at the consumers expense

691. The MRP must be robust and based on liquid market indices. It is important that the source(s) selected avoid potential for manipulation but also reflect the weight of actual transactions.

Barriers to Entry

5.4.5.xii P9 - Avoid arrangements which favour a particular corporate structure

692. Meeting the Government's challenging renewable targets requires access to and engagement with the widest possible pool of potential investors from the UK and abroad. It is a core design principle that arrangements should not unduly favour a particular corporate structure neither in the award or the operation of these contracts.

693. With respect to the operation of the contract, a particular area of concern is whether investors in smaller scale low-carbon projects (i.e. onshore wind) will be disadvantaged relative to larger established energy companies. Firstly, individual developers, which have the expertise to plan, build and technically run small scale low-carbon projects will often not have the ability or capacity to manage the trading and balancing requirements associated with operation in the GB markets. Secondly, there are considerable commercial and costs benefits associated with managing intermittent generation projects as part of a wider portfolio of generation assets rather than on a stand-alone basis. Hence, larger energy companies with strong balance sheets have a considerable advantage over individual developers. The benefit of a Vertically Integrated portfolio structure is generally regarded as advantageous, particularly in the GB market, due to the nature of the balancing market with dual cash out prices which promotes self-insuring of imbalances.

694. These issues exist today in the current GB market where individual low-carbon projects under the RO regime typically require backing of a Power Purchase Agreement (PPA) with one of the incumbent energy companies. These PPA contracts transfers the commercial management of balancing and short-term operations from the developer to the energy company in return for a fee (often a discount on the package of power and certificate). Notwithstanding the removal of the renewable obligation on suppliers, there is a genuine barrier to entry for small scale developers. It is for this reason that the proposed arrangements for intermittent generation is based on a simple FiT CfD instrument settled against day-ahead prices (leaving generators with less energy price risk than under the current RO regime).

5.4.5.xiii P10 - Mitigate perceived or real impact associated with the removal of the supplier obligation under the existing RO regime

695. One of the concerns from Private Financiers and independent generators is that the removal of the supplier obligation that exists under the RO will leave investors with no buyer for their power. However it should be recognised that there is no obligation for suppliers to buy renewable energy under the RO. Under the existing RO a supplier can buy ROCs to meet their "obligation" but they do not have to. As an alternative they can pay the Buy-Out of £30/MWh (indexed to inflation). Suppliers buy power with associated ROCs (and LECs) only because they can do so more cheaply than buying power in the market and meet their "obligation" more cheaply than paying the buyout.

696. It is important to understand that the obligation existing under the RO is a soft one. It is typically only the Big-6 and well established aggregators that purchase renewable energy under the existing structure.

697. Under EMR, the introduction of a FiT CfD will guarantee a generator income between the MRP and strike price if it generates regardless of whether the power has been sold to an off-taker. Selling the power will increase revenue and if sold at the MRP, ignoring basis risk, will crystallise incomes to the strike price. The generator will no longer have to find a buyer for ROCs. A generator (either through the OTC market or a bilateral PPA) will only be required to sell power (not ROCs which only have value to a supplier) under the new arrangement, opening up the number of potential purchasers beyond the Big-6.

698. It is important to understand the mechanics of the new FiT CfDs. They are simpler than the ROC structure with a value and a recycling element which is complex to understand. The exposure to the power market is significantly reduced for many generation classes which only take exposure to day-ahead basis risk compared to the existing situation which provides no mitigation of power price risk. Intermittent generation will not need to have visibility over the forward curve but simply be satisfied that a generator will sell their power into the MRP (directly in to the market or via a PPA). There is though a concern that a lack of liquidity and/or market depth will affect a generators ability to sell in the market and these liquidity concerns are dealt with elsewhere (see P13).

5.4.5.xiv P11 - Ensure open and competitive process of awarding contracts

699. The proposed process for awarding contracts is described separately but it is also important to consider how the structure of the FiT CfD could facilitate a competitive process for award contracts.

Coherence

5.4.5.xv P12 - Ensure consistency between FiT CfD contracts and other elements of the EMR reform programme including Carbon Price Floor and introduction of capacity payments

700. The "Coherence" principle expresses the necessity for making sure that the reform initiatives included within the EMR are internally consistent and hence likely to deliver a coherent overall reform programme.

5.4.5.xvi P13 - Ensure consistency between EMR reforms and Ofgem liquidity initiatives

701. Ofgem is progressing proposals for intervening in the market to improve liquidity and contestability. This initiative is one of a number which are likely to impact on the operation and functioning of the market.

Practicality & Durability

5.4.5.xvii P14 - Be able to adapt to changing market environment and rules (including coupling with a wider pan-European market)

702. It is clear that FiT CfDs issued in the next few years under the EMR will need to remain relevant during their lifetimes. Liquidity (see P15) will change over time, and increased interconnection will drive market coupling with Europe. The contract clauses need to be robust to make the contracts bankable but there is also a need for the contracts to be able to adapt to prevailing market conditions. For example, the need to change indices easily (eg through an independent Trustee) to reflect the prevailing nature of the market will be important without contract-opening renegotiations.

703. However, the overall objective is ensuring the instrument design will have contract parameters that are entirely unambiguous to enhance their bankability, hence lowering the cost of capital required by an investor. Consideration is also made to drive out opportunities to "game" the contracts and hence increase the costs to society (see P8).

5.4.5.xviii P15 - Recognise that current lack of liquidity poses a significant interim challenge

704. A FiT CfD needs a robust, reliable MRP which cannot be manipulated to provide effective payments to and from the generator. There is a significant interim challenge to liquidity in general. The design of FiT CfDs to settle against today's market must also be able to do so tomorrow.

705. As we describe in P4 it is important, where possible, for contracts to contribute to market liquidity and certainly not detract from initiatives underway to improve liquidity.

5.4.5.xix P16 - Keep contracts simple in a complex market environment

706. In order to attract investment from as wide a possible spectrum of financiers it is important that the contracts can easily be understood. Whilst large contracts for certain types of generation will undoubtedly be awarded to companies or consortia with significant market understanding and expertise, it is also important to attract less sophisticated developers. It is essential that the FiT CfDs proposed can be understood by non-energy market practitioners to attract investment and to be bankable. As with the RO, we anticipate it will take time for new contracts to be approved as instruments by e.g. banks who will need to get them signed-off by credit committees before capital can be released to develop new projects.

707. It should be recognised that the power produced under a FiT CfD will be sold into the market in exactly the same way as power from other generation forms. It will no longer be subject to being sold as part of a bundle with green certificates (ROCs or other certificates). Instead the generator will sell into the MRP to guarantee income or sign a PPA with an offtaker/supplier/aggregator. This reduces complexity and makes it simpler for an investor with limited experience of the energy markets to manage their risks.

5.4.5.xx P17 - Recognise that internal capabilities of the target investor community will vary across different classes of generation

708. Coupled with attracting capital initially the contracts also need to be simple enough to operate within the existing market framework. We recognise that many operators in the RO currently rely on energy specialists for a PPA to manage the offtake or for a supplier to buy their power. To attract investment the ability to operate contracts must therefore be at least as attractive as they are currently. Products sold in large volumes, such as intermittent FiT CfDs, are likely to be awarded to less sophisticated operators (as well as those well versed in energy markets) so must be simple. This is an important element for EMR to be successful in decarbonising the sector and we recognise this in the design.

Annex J: Further detail on impacts on bills and prices

Impact on bills under central fossil fuel prices

709. Table 33 below show the estimated impact of EMR policies in a central fossil fuel price scenario on an average domestic, medium-sized non-domestic [95] and large energy intensive user's[96] average annual electricity bill relative to an updated baseline scenario electricity bill. The impact is shown both in terms of absolute difference to the baseline bill and the percentage difference.

710. The estimated absolute impact of the EMR on the electricity bill of a large energy intensive user is an upper bound estimate assuming policy subsidy costs are distributed evenly across all electricity users (including households) on a per unit basis by retail energy suppliers. This is a simplifying assumption. Suppliers may choose a different strategy for spreading policy subsidy costs across different types of users depending on the differing nature of competition across different types of electricity customers and the nature of the policy.

Table 33: Impact of EMR packages with Strategic Reserve on average annual electricity bills for domestic, medium-sized non-domestic and a large energy intensive user (real 2009 £) – central fossil fuel prices

Relative to updated baseline bill	**Updated Baseline average bill**	**FiT CfD package – SR**	**Premium FiT – SR**
	Domestic (£)		
2010	£485	-	-
2011-2015	£468	-	0% (£1)
2016-2020	£486	-1% (-£4)	1% (£4)
2021-2025	£560	0% (£2)	0% (£2)
2026-2030	£648	-4% (-£24)	-1% (-£4)
2030	£682	-6% (-£40)	-5% (-£35)
Average 2010-2030	*£538*	*-1% (-£6)*	*0% (£1)*
	Medium-sized non-domestic (£)		
2010	£913,000	-	-
2011-2015	£966,000	0% (£1,000)	0% (£1,000)
2016-2020	£1,148,000	-1% (-£12,000)	1% (£11,000)
2021-2025	£1,415,000	0% (£5,000)	0% (£7,000)
2026-2030	£1,486,000	-4% (-£63,000)	-1% (-£10,000)
2030	£1,530,000	-7% (-£104,000)	-6% (-£92,000)
Average 2010-2030	*£1,237,000*	*-1% (-£17,000)*	*0% (£2,000)*
	Energy intensive Industrial user consuming 100,000MWh of electricity (£)		

[95] Medium-sized non-domestic users are assumed to have an annual electricity consumption before energy efficiency policies of 11,000MWh, consistent with the midpoint of the Eurostat "medium" size-band for non-domestic electricity.

[96] Electricity consumption for an illustrative Energy Intensive user is assumed to be 100,000MWh before efficiency savings. The percentage impacts also apply for different scales of energy intensive users (as long as they consume above the Eurostat lower bound of 8,800MWh of electricity), while the absolute impacts are scalable – e.g. The results show that the average electricity bill over the period 2010-2030 for an energy intensive user consuming 100,000MWh was £9,966,000 and the impact of the FiT CfD package with SR is estimated to be -2% (-£154,000). For a user consuming 200,000MWh of electricity, their average electricity bill would be estimated to be around (200,000 / 100,000 = 2) x (9,966,000) = £19,932,000 and the impact of the FiT CfD package with SR would be -2% (2 x -154,000 = -£308,000).

2010	£6,905,000	-	-
2011-2015	£7,471,000	0% (£9,000)	0% (£13,000)
2016-2020	£9,122,000	-1% (-£111,000)	1% (£101,000)
2021-2025	£11,562,000	0% (£43,000)	1% (£61,000)
2026-2030	£12,320,000	-5% (-£587,000)	-1% (-£92,000)
2030	£12,617,000	-8% (-£957,000)	-7% (-850,000)
Average 2010-2030	*££9,966,000*	*-2% (-£154,000)*	*0% (£20,000)*

711. Table 34 below shows the impact on bills with a Reliability Market (RM) option for Capacity Mechanism in the Premium FiT and FiT CfD packages. Also in these scenarios the FiT CfD package is slightly better than a Premium FiT package in terms of overall average impact on consumer bills for the whole period, although the overall impacts remain small compared to the baseline.

Table 34: Impact of EMR packages with a Reliability Market on average annual electricity bills for domestic and non-domestic consumers – central fossil fuel prices

Relative to updated baseline bill	**Updated Baseline average bill**	**FiT CfD package – RM**	**Premium FiT – RM**
	Domestic (£)		
2010	£485	-	-
2011-2015	£468	-	0% (£1)
2016-2020	£486	0% (-£1)	2% (£11)
2021-2025	£560	-3% -£16)	1% (£3)
2026-2030	£648	-4% (-£27)	2% (£10)
2030	£682	-6% (-£41)	-1% (-£8)
Average 2010-2030	*£538*	*-2% (-£10)*	*1% (£6)*
	Medium-sized non-domestic (£)		
2010	£913,000	-	-
2011-2015	£966,000	0% (£1,000)	0% (£4,000)
2016-2020	£1,148,000	0% (-£2,000)	3% (£34,000)
2021-2025	£1,415,000	-3% (-£47,000)	1% (£10,000)
2026-2030	£1,486,000	-5% (-£72,000)	2% (£28,000)
2030	£1,530,000	-7% (-£106,000)	-1% (-£21,000)
Average 2010-2030	*£1,237,000*	*-2% (-£28,000)*	*1% (£18,000)*
	Energy intensive Industrial user consuming 100,000MWh of electricity (£)		
2010	£6,905,000	-	-
2011-2015	£7,471,000	0% (£6,000)	0% (£36,000)
2016-2020	£9,122,000	0% (-£15,000)	3% (£306,000)
2021-2025	£11,562,000	-4% (-£435,000)	1% (£94,000)
2026-2030	£12,320,000	-5% (-£669,000)	2% (£265,000)
2030	£12,617,000	-8% (-£977,000)	-2% (-£194,000)
Average 2010-2030	£9,966,000	*-3% (-£265,000)*	*2% (£167,000)*

Impact on electricity prices under central fossil fuel prices

712. Table 35 below shows the impact on average annual electricity prices of the four EMR packages, compared to estimated baseline electricity prices. Because EMR policies do not affect electricity consumption, the impact on prices is the same in percentage terms as the impact on bills.

Table 35 Impact of EMR packages on average electricity prices for domestic and non-domestic consumers (£/MWh, real 2009) – central fossil fuel prices.

Relative to updated baseline prices	**Updated Baseline average prices**	**FiT CfD package – SR**	**FiT CfD package – RM**	**Premium FiT – SR**	**Premium FiT – RM**
Domestic (£/MWh)					
2010	£116	-	-	-	-
2011-2015	£125	£0	£0	£0	£0
2016-2020	£147	-£1	£0	£1	£3
2021-2025	£169	£0	-£5	£1	£1
2026-2030	£178	-£6	-£7	-£1	£3
2030	£181	-£11	-£11	-£9	-£2
Average 2010-2030	*£153*	*-£2*	*-£3*	*£0*	*£2*
Medium-sized non-domestic (£/MWh)					
2010	£84	-	-	-	-
2011-2015	£90	£0	£0	£0	£0
2016-2020	£110	-£1	£0	£1	£3
2021-2025	£137	£0	-£5	£1	£1
2026-2030	£145	-£6	-£7	-£1	£3
2030	£149	-£10	-£10	-£9	-£2
Average 2010-2030	*£119*	*-£2*	*-£3*	*£0*	*£2*
Energy intensive industrial user consuming 100,000MWh of electricity (£/MWh)					
2010	£70	-	-	-	-
2011-2015	£77	£0	£0	£0	£0
2016-2020	£96	-£1	£0	£1	£3
2021-2025	£122	£0	-£5	£1	£1
2026-2030	£129	-£6	-£7	-£1	£3
2030	£132	-£10	-£10	-£9	-£2
Average 2010-2030	£104	*-£2*	*-£3*	*£0*	*£2*

Impact on bills under high fossil fuel prices

713. The table below shows the impact on average annual electricity bills under the Premium FiT – SR and FiT CfD – SR packages under high fossil fuel prices, compared to an estimated baseline bill modelled also under high fossil fuel prices.

Table 36 Impact of EMR packages with Strategic Reserve on average annual electricity bills - high fossil fuel prices

Relative to updated High fossil fuel price baseline bill	**Updated Baseline average bill (High FF)**	**FiT CfD package – SR (High FF)**	**Premium FiT – SR (High FF)**
Domestic (£)			
2010	£522	-	-
2011-2015	£509	-	-
2016-2020	£542	-2% (-£10)	-
2021-2025	£627	-9% (-£58)	-4% (-£22)
2026-2030	£724	-10% (-£72)	-1% (-£5)
2030	£727	-7% (-£54)	1% (£4)
Average 2010-2030	*£597*	*-6% (-£33)*	*-1% (-£6)*

Medium-sized non-domestic (£)			
2010	£1,006,000	-	-
2011-2015	£1,078,000	0% (£1,000)	0% (£1,000)
2016-2020	£1,318,000	-2% (-£30,000)	0% (£1,000)
2021-2025	£1,611,000	-11% (-£173,000)	-4% (-£67,000)
2026-2030	£1,690,000	-11% (-£192,000)	-1% (-£15,000)
2030	£1,647,000	-8% (-£140,000)	1% (£10,000)
Average 2010-2030	*£1,404,000*	*-7% (-£94,000)*	*-1% (-£19,000)*
Energy intensive industrial user consuming 100,000MWh of electricity (£)			
2010	£7,739,000	-	-
2011-2015	£8,483,000	0% (£11,000)	0% (£11,000)
2016-2020	£10,673,000	-3% (-£275,000)	0% (£9,000)
2021-2025	£13,365,000	-12% (-£1,581,000)	-5% (-£613,000)
2026-2030	£14,221,000	-13% (-£1,784,000)	-1% (-£137,000)
2030	£13,701,000	-9% (-£1,291,000)	1% (£97,000)
Average 2010-2030	*£11,497,000*	*-8% (-£864,000)*	*-2% (-£174,000)*

714. As can be seen from Table 36 above, consumers could benefit from relatively lower bills on average for the period to 2030 in both scenarios under high fossil fuel prices, and particularly so in the FiT CfD package, compared to a baseline bill under high fossil fuel prices. With higher fossil fuel prices (particularly gas), wholesale prices and low-carbon payments are lower in the EMR packages than in the baseline[97].

Impact on bills under low fossil fuel prices

715. Table 37 below shows the impact on average annual electricity bills under the Premium FiT – SR and FiT CfD – SR packages under low fossil fuel prices, compared to an estimated baseline bill under low fossil fuel prices.

716. This analysis suggests that over the period to 2030 as a whole with low fossil fuel prices, average electricity bills in the Premium FiT package could be marginally lower than the baseline, whilst bills under the FiT CfD package could be somewhat higher than the baseline bill.

Table 37: Impact of EMR packages with Strategic Reserve on average annual electricity bills - low fossil fuel prices

Relative to updated Low fossil fuel price baseline bill	**Updated Baseline average bill (Low FF)**	**FiT CfD package – SR (Low FF)**	**Premium FiT – SR (Low FF)**
Domestic (£)			
2010	£404	-	-
2011-2015	£395	0% (-£1)	-
2016-2020	£434	3% (£13)	0% (-£2)
2021-2025	£469	4% (£20)	-1% (-£3)
2026-2030	£552	0% (£2)	-1% (-£8)
2030	£585	2% (£9)	-3% (-£19)
Average 2010-2030	*£460*	*2% (£8)*	*-1% (-£3)*
Medium-sized non-domestic (£)			
2010	£711,000	-	-

[97] Although wholesale prices (and retail prices and bills as a result) across all scenarios and the baseline, will be higher than in the same scenarios under lower fossil fuel prices.

2011-2015	£768,000	0% (-£2,000)	0% (-£1,000)
2016-2020	£994,000	4% (£41,000)	0% (-£5,000)
2021-2025	£1,144,000	5% (£58,000)	-1% (-£7,000)
2026-2030	£1,229,000	0% (£4,000)	-2% (-£21,000)
2030	£1,275,000	2% (£24,000)	-4% (-£49,000)
Average 2010-2030	*£1,018,000*	*2% (£24,000)*	*-1% (-£8,000)*
Energy intensive industrial user consuming 100,000MWh of electricity (£)			
2010	£5,085,000	-	-
2011-2015	£5,670,000	0% (-£16,000)	0% (-£6,000)
2016-2020	£7,718,000	5% (£371,000)	-1% (-£45,000)
2021-2025	£9,080,000	6% (£531,000)	-1% (-£68,000)
2026-2030	£9,942,000	0% (£37,000)	-2% -£195,000
2030	£10,262,000	2% (224,000)	-4% (-£453,000)
Average 2010-2030	*£7,959,000*	*3% (£220,000)*	*-1% (-£75,000)*