Title: **Electricity Market Reform - options for ensuring electricity security of supply and promoting investment in low-carbon generation**	Impact Assessment (IA)
	IA No:
	Date: 14/12/2010
	Stage: Development/Options
	Source of intervention: Domestic
Lead department or agency: DECC	**Type of measure:** Primary legislation
Other departments or agencies: HMT	**Contact for enquiries:** Andy Goodwin

Summary: Intervention and Options

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

This impact assessment considers the impacts of a range of measures to ensure security of supply and promote investment in low-carbon generation as part of the electricity market reform project. Our analysis 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. Current electricity market arrangements are not likely to deliver the required investment in low-carbon generation for a number of reasons including the carbon price being too low and its future level too uncertain; and there is a bias towards high carbon generation.

What are the policy objectives and the intended effects?

The two primary policy objectives are to reform the electricity market arrangements so that the government's decarbonisation objectives can be met cost effectively and to ensure security of supply for the GB electricity system towards the end of the decade and beyond. 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? Please justify preferred option (further details in Evidence Base)

Five policy options have been considered for driving investment in low-carbon: premium payments; an emission performance standard (EPS); carbon price support (CPS); contracts for difference (CfD): and fixed payments. CfD are preferred as the certainty they provide minimises the potential for excessive rents and result in lower costs of capital, this reduces impacts on consumers of meeting the UK's decarbonisation objectives. CfD provide more certainty that carbon goals will be met than the premium payment option and retain a link to the electricity price and the efficiency signals that this sends. Three policy options for ensuring security of supply have been considered: option 1 - Improving the energy-only market: no capacity mechanism (CM); option 2 - A market-wide CM: a CM for all generators; option 3 - a targeted CM (a CM for some generators). A targeted CM is preferred as it allows targeting of specific types of capacity, reduces the risks of blanket windfalls to existing generators and disruption to current market arrangements, whilst achieving this at lower cost compared to a market-wide mechanism while still ensuring security of supply needs are met. CfD have been combined with a targeted CM, a targeted EPS and CPS to form a preferred package. EPS provides an important backstop and CPS key benefits to investors along with revenues to government. Given there remain some design and implementation issues to resolve, it is important to consider premium payments as a credible alternative in the consultation document.

When will the policy be reviewed to establish its impact and the extent to which the policy objectives have been achieved?	Policy will be reviewed following the White Paper
Are there arrangements in place that will allow a systematic collection of monitoring information for future policy review?	This will be considered as part in the White Paper

Ministerial Sign-off For consultation stage Impact Assessments:

I have read the Impact Assessment and I am satisfied that, given the available evidence, it represents a reasonable view of the likely costs, benefits and impact of the leading options.

Signed by the responsible  .... Date: 16 December 2010.......

Summary: Analysis and Evidence — Policy Option 1

Description: Do nothing - Renewables Obligation for incentivising investment in renewables. Investment in other low-carbon incentivised through the EU ETS.

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

COSTS (£m)	Total Transition (Constant Price)	Years	Average Annual (excl. Transition) (Constant Price)	Total Cost (Present Value)
Low	n/a		Not applicable (n/a)	n/a
High	n/a		n/a	n/a
Best Estimate	n/a		n/a	n/a

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

This option is the baseline against which other options 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 200gCO_2/kWh by 2030. This is considered to be insufficient to put the UK on the path to meeting its long-term decarbonisation objectives – for example the Committee on Climate Change has recommended 50gCO_2/KWh by 2030. The Government has not yet set a decarbonisation target beyond the third carbon budget period (2018-22).
Potentially results in excessive rents for renewables because of lack of carbon price foresight.
Barriers to entry are high under the current arrangements with subsequent risks for competition.

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

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 will be no investment hiatus for renewables as a result of moving to a new mechanism.

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

n/a

Impact on admin burden (AB) (£m):			Impact on policy cost savings (£m):	In scope
New AB: n/a	**AB savings:** n/a	**Net:** n/a	**Policy cost savings:** n/a	No

Summary: Analysis and Evidence — Packages: option 1

Description: Payment on top of electricity price (premium payment) for incentivising investment in all low-carbon, in addition to the EU ETS, combined with carbon price support (CPS), a targeted emissions performance standard (EPS) and a targeted capacity mechanism.

Price Base Year 2010	PV Base Year 2010	Time Period Years 20	Net Benefit (Present Value (PV)) (£m 2009 real)		
			Low:	High:	Best Estimate:- 7,200

COSTS (£m)	Total Transition (Constant Price)	Years	Average Annual (excl. Transition) (Constant Price)	Total Cost (Present Value)
Low				
High				
Best Estimate				27,300

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

Capital costs for the electricity generation sector increase by £27.3bn compared to the baseline because of the higher capital costs of low-carbon technologies compared to conventional fossil fuel fired generation plants. Costs to consumers is dependent on efficiency of incentive setting (£5/MWh error in incentive setting results in £4bn additional costs for consumers, NPV 2010-2030); incentives setting mechanisms such as auctioning can be used to mitigate these risks.

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

Affordability: potentially results in excessive rents to low-carbon generators depending on carbon price foresight; lower foresight means that payments required to stimulate investment are higher than actually needed once carbon price rises in future. Barriers to entry: does not significantly affect barriers to entry. Durability: not robust to declining average wholesale electricity prices in future.

BENEFITS (£m)	Total Transition (Constant Price)	Years	Average Annual (excl. Transition) (Constant Price)	Total Benefit (Present Value)
Low				
High				
Best Estimate				20,000

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

Power sector in the UK will have to buy fewer EU ETS allowance saving around £11.5bn. In addition, non-carbon running costs (e.g. fuel) for generation plant will be around £7.7bn lower because of the lower running costs of low-carbon plants Air quality benefits of £0.4bn to £0.9bn (NPV) in this package because of reduced fossil fuel generation. Security of supply: no unserved energy as a result of the targeted capacity mechanism (£200m). Affordability: results in more certainty for investors reducing financing costs than in the baseline but by less than under the CfD and fixed payment options.

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

Efficiency: retains the link to the electricity price resulting in efficiency benefits. Practicality: premium payments are relatively straightforward to implement. Targeted EPS prevents development and operation of new unabated coal, providing a backstop. CPS reduces liabilities for investors before the premium payment is made, reduces cumulative emissions in the UK and provides revenues to Government. More confidence in the security of supply resulting from the targeted capacity mechanism. Benefits of innovation are not included in the NPV calculations.

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

The period of the modelling is between 2010 and 2030, therefore the analysis does not account for the benefits due to a rising carbon price after 2030. Under low gas price scenario and low-carbon price scenario, fails to achieved same level of decarbonisation in the 2030 (100gCO_2/KWh) assuming payments are not changed, though costs are lower for consumers as a result. Under high gas price scenario – overshoots on level of decarbonisation and costs for consumer are higher. In high demand scenario, NPV is positive over the period (around £2.5bn) when the technology and decarbonisation profile is the same as packages options 2 and 3. See decarbonisation option 1 for the impacts of high and low gas prices on the NPV.

Impact on admin burden (AB) (£m):			Impact on policy cost savings (£m):	In scope
New AB: n/a	AB savings: n/a	Net: n/a	New AB: n/a	No

Summary: Analysis and Evidence — Packages: option 2

Description: Contracts for difference (CfD), on the wholesale electricity price, to incentivise investment in all forms of low-carbon generation combined with carbon price support, a targeted emissions performance standard and a targeted capacity mechanism.

Price Base Year 2010	PV Base Year 2010	Time Period Years 20	Net Benefit (Present Value (PV)) (£m)		
			Low: Optional	**High:** Optional	**Best Estimate: -3,900**

COSTS (£m)	Total Transition (Constant Price)	Years	Average Annual (excl. Transition) (Constant Price)	Total Cost (Present Value)
Low				
High				
Best Estimate				**24,000**

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

Capital costs for the electricity generation sector increase by £24.0bn compared to the baseline because of the higher capital costs of low-carbon technologies compared to conventional fossil fuel fired generation plants. Costs to consumers is dependent on efficiency of incentive setting (£5/MWh error in incentive setting could result in £4bn additional costs for consumers, NPV 2010-2030) ; incentives setting mechanisms such as auctioning can be used to mitigate these risks.

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

Practicality: CfD are complex mechanisms that may result in an investment hiatus and unintended consequences during implementation. Efficiency: generators are no longer fully exposed to long-term electricity price risk, which is one of a number of factors which helps prevent an (inefficient) over-supply of capacity in the market which transfers risk to government in terms of forecasting demand.

BENEFITS (£m)	Total Transition (Constant Price)	Years	Average Annual (excl. Transition) (Constant Price)	Total Benefit (Present Value)
Low				
High				
Best Estimate				**20,000**

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

Power sector in the UK will have to buy fewer EU ETS allowance saving around £11.5bn. Running costs (excluding carbon) for generation plant will be around £7.7bn lower. Air quality benefits of £0.4bn to £1.0bn (NPV) in this package because of reduced fossil fuel generation. Security of supply: no unserved energy as a result of the targeted capacity mechanism (£200m). Affordability: more certainty reduces costs for consumers as potential for excessive rents for producers is lower and financing costs are lower compared to premium payments.

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

Efficiency: retains the link to the electricity price resulting in efficiency benefits. Barriers to entry: reduces barriers to entry to some extent. Targeted EPS prevents development and operation of new unabated coal, providing a backstop. CPS reduces liabilities for investors before the premium payment is made, reduces cumulative emissions in the UK and provides revenues to Government. More confidence in the security of supply resulting from the targeted capacity mechanism. Durability: robust to declining average wholesale electricity prices in future. Benefits of innovation are not included in the NPV.

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

The period of the modelling is between 2010 and 2030, therefore the analysis does not account for the benefits due to a rising carbon price after 2030. In low gas price and low-carbon price scenarios, investment in low-carbon is not affected but higher cost for consumers relative to the premium payments as costs under premium payments are lower.In high gas price scenario, similar level of low-carbon investment is achieved but carbon emissions are increased in 2030 due to more coal generation. Lower costs for consumers relative premium payments. In high demand scenario, NPV is positive (£6.6bn) over the period. See decarbonisation option 4 for the impacts of high and low gas prices scenarios on the NPV.

Impact on admin burden (AB) (£m):			Impact on policy cost savings (£m):	In scope
New AB:	**AB savings:**	**Net:**	**Policy cost savings:**	Yes/No

Summary: Analysis and Evidence — Packages: option 3

Description: Fixed payments, separate to the wholesale electricity price, to all forms of low-carbon generation combined with carbon price support, a targeted emissions performance standard and a targeted capacity mechanism.

Price Base Year 2010	PV Base Year 2010	Time Period Years 20	Net Benefit (Present Value (PV)) (£m)		
			Low:	High:	Best Estimate: -3,900

COSTS (£m)	Total Transition (Constant Price)	Years	Average Annual (excl. Transition) (Constant Price)	Total Cost (Present Value)
Low				
High				
Best Estimate				24,300

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

Capital costs for the electricity generation sector increase by £24.2bn compared to the baseline because of the higher capital costs of low-carbon technologies compared to conventional fossil fuel fired generation plants. Security of supply: no unserved energy as a result of the targeted capacity mechanism (£200m). Costs to consumers is dependent on efficiency of incentive setting (£5/MWh error in incentive setting results in £4bn additional costs for consumers, NPV 2010-2030) ; incentives setting mechanisms such as auctioning can be used to mitigate these risks.

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

Efficiency: does not retain the link to the electricity price potentially resulting in additional costs. Generators are no longer fully exposed to long-term electricity price risk, which is one of a number of factors which helps prevent an (inefficient) over-supply of capacity in the market which transfers risk to government in terms of forecasting demand. Practicality: fixed payments required additional mechanisms to feed electricity back into the market

BENEFITS (£m)	Total Transition (Constant Price)	Years	Average Annual (excl. Transition) (Constant Price)	Total Benefit (Present Value)
Low				
High				
Best Estimate				20,400

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

Power sector in the UK will have to buy fewer EU ETS allowances saving around £11.8bn. Running costs (excluding carbon) for generation plant will be around £7.7bn lower.
Air quality benefits of £0.5bn to £1.0bn (NPV) in this package because of reduced fossil fuel generation.
Affordability: more certainty reduces costs for consumers as potential for excessive rents for producers is lower and financing costs are lower compared to premium payments.

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

Barriers to entry: reduces barriers to entry though not significantly. Targeted EPS prevents development and operation of new unabated coal, providing a backstop. CPS reduces liabilities for investors before the premium payment is made, reduces cumulative emissions in the UK and provides revenues to Government. More confidence in the security of supply resulting from the targeted capacity mechanism. Durability: robust to declining average wholesale electricity prices in future. Benefits of innovation are not included in the NPV calculations.

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

The period of the modelling is between 2010 and 2030, therefore the analysis does not account for the benefits due to a rising carbon price after 2030. In low gas price and low-carbon price scenarios, investment in low-carbon is not affected but higher cost for consumers relative to the premium payments as costs under premium payments are lower. In high gas price scenario, similar level of low-carbon investment is achieved but carbon emissions are increased in 2030 due to more coal generation. Lower costs for consumers relative premium payments. In high demand scenario, NPV is positive (£6.6bn) over the period. See decarbonisation option 4 for the impacts of high and low gas prices scenarios on the NPV.

Impact on admin burden (AB) (£m):			Impact on policy cost savings (£m):	In scope
New AB:	AB savings:	Net:	Policy cost savings:	Yes/No

Summary: Analysis and Evidence — Security of supply: option 1

Description: Improve operation of current market (Improve Energy Only)

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

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'

N/A

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

Efficiency impacts: Uncertainty around participation of DSR may still remain, price risks become greater with sharper prices, where hedging products do not adequately develop (i.e. market iliquidity persisting in some form) this could reduce innovation for new technologies.

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'

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

Efficiency impacts: Some improvement due to involvement of DSR and more efficient renewables dispatch.
Competition: Liquidity enhancements can reduce barriers to entry, so should increase competition.
Security of supply: Moderate improvement due to sharpened price signals (Ofgem estimate similar reforms could improve capacity margins by 1- 2%), but supply risks will remain particularly from investment cycles and where generators perceive risks of intervention due to high prices.
Market distortion: Measures will reduce market distortion and enhance market functioning.

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

Impact on admin burden (AB) (£m):			**Impact on policy cost savings (£m):**	**In scope**
New AB:	**AB savings:**	**Net:**	**Policy cost savings:**	Yes/No

Summary: Analysis and Evidence — Security of supply: option 2

Description: Market-wide Capacity Mechanism

Price Base Year 2010	PV Base Year 2010	Time Period Years 20	Net Benefit (Present Value (PV)) (£m)		
			Low: -775	**High: 95**	**Best Estimate: -340**

COSTS (£m)	**Total Transition** (Constant Price)	Years	**Average Annual** (excl. Transition) (Constant Price)	**Total Cost** (Present Value)
Low				
High				
Best Estimate			100	**1270**

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

The costs relate to generation costs incurred by existing plant that would otherwise have closed that has been incentivised to stay on the system by the payment. The mechanism results in the market maintaining an non-economically optimal level of capacity.

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

Distributional impacts: Market-wide capacity mechanism results in larger rents to producers (producer surplus), depending on the means of implementation.
Competition: Could have some negative effects if liquidity deteriorates due to increased monitoring in spot markets reinforcing bilateral contracting. However risks are deemed to be low to neutral since there are counteracting factors supporting liquidity as some participants may prefer to buy from transparent markets.
Other costs: Administrative costs, system monitoring (gaming) and unintended effects.

BENEFITS (£m)	**Total Transition** (Constant Price)	Years	**Average Annual** (excl. Transition) (Constant Price)	**Total Benefit** (Present Value)
Low			41	**495**
High			112	**1364**
Best Estimate	N/A		77	**929**

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

Benefits relate to enhanced prospects for security of supply to society from lower levels of expected energy unserved and lower requirements to use existing demand side resources relative to the baseline . Benefits are assessed with low and high VOLL estimates of £10,000/MWh and £30,000/MWh respectively.

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

Efficiency impacts: Reduces investor uncertainty and cost of capital with corresponding resource savings, incentivises demand side, including energy efficiency and storage.
Competition: Positive effects from increased involvement of demand side resources (DSR)
Security of supply: Beneficial, since option will bring forward additional resources.
Market distortion: Market structure changes but minimal distortion between existing and new plant incentive.

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

The Redpoint quantitative analysis does not include all the costs and benefits of the proposals (for example the resource cost savings from participation of new demand side resources), primarily since these are dependent on mechanism design and some cannot be quantified. However the cost benefit section attempts to synthesise both the Redpoint analysis together with the available qualitative evidence.

Modelling assumes that a central body can accurately forecast capacity, where there are errors the costs will be greater to consumers. The modelling also assumes consumer valuation of costs of supply disruptions (value of lost load, VOLL) at £10,000/MWh. Additional sensitivity with VOLL at £30,000/MWh is also assessed.

Impact on admin burden (AB) (£m):			**Impact on policy cost savings (£m):**	**In scope**
New AB:	**AB savings:**	**Net:**	**Policy cost savings:**	Yes/No

Summary: Analysis and Evidence — Security of supply: option 3

Description: Targeted Capacity Mechanism

Price Base Year 2010	PV Base Year 2010	Time Period Years 20	Net Benefit (Present Value (PV)) (£m)		
			Low: -694	High: 114	Best Estimate: -290

COSTS (£m)	Total Transition (Constant Price)	Years	Average Annual (excl. Transition) (Constant Price)	Total Cost (Present Value)
Low				
High				
Best Estimate			90	**1098**

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

The costs relate to generation costs incurred by existing plant that would otherwise have closed that has been incentivised to stay on the system. In addition to build costs and generation costs (net of carbon savings) of new plant also incentivised by the payment .

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

Competition: Some negative effects on liquidity as with market-wide CM but likely to be neutral to low.
Market distortion: Risks of distortion if the scarcity signals not restored for rest of the market,
Other: Administrative costs, system monitoring for gaming etc and unintended consequences but these costs are likely to be much less than with a market-wide CM.

BENEFITS (£m)	Total Transition (Constant Price)	Years	Average Annual (excl. Transition) (Constant Price)	Total Benefit (Present Value)
Low			33	**404**
High			100	**1212**
Best Estimate	N/A		67	**808**

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

Benefits relate to enhanced prospects for security of supply to society from lower levels of expected energy unserved relative to the baseline. Benefits are assessed with low and high VOLL estimates of £10,000/MWh and £30,000/MWh respectively.

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

Distributional impacts: Option is targeted, hence less rent capture/producer surplus under this option.
Efficiency impacts: Reduces investor uncertainty and cost of capital with corresponding resource savings, can incentivise demand side (including energy efficiency and storage) and flexible resources.
Competition: Positive effects from increased involvement of new market participants/resources
Security of supply: Improves because option will bring forward targeted amounts of additional resource.

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

The Redpoint quantitative analysis does not include all the costs and benefits of the proposals (for example the resource cost savings from participation of demand side resources), primarily since these are dependent on mechanism design and some cannot be quantified. However the cost benefit section attempts to synthesise both the Redpoint analysis together with the available qualitative evidence.

Modelling assumes that a central body can accurately forecast capacity, where there are errors the costs will be greater to consumers. Also that the tendered capacity does not distort the wholesale market. Moreover consumer valuations of the costs of supply disruptions (value of lost load) are assumed at £10,000MWh. Additional sensitivity with VOLL at £30,000/MWh is also assessed.

Impact on admin burden (AB) (£m):			Impact on policy cost savings (£m):	In scope
New AB:	AB savings:	Net:	Policy cost savings:	Yes/No

Summary: Analysis and Evidence — Decarbonisation: option 1

Description: Payment on top of electricity price (premium payment) for incentivising investment in all low-carbon, in addition to the EU ETS.

Price Base Year 2010	PV Base Year 2010	Time Period Years 20	Net Benefit (Present Value (PV)) (£m 2009 real)		
			Low: -9,000	High: -	Best Estimate: - 6,700

COSTS (£m)	Total Transition (Constant Price)	Years	Average Annual (excl. Transition) (Constant Price)	Total Cost (Present Value)
Low				11,900
High				-
Best Estimate				16,600

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 because of the higher capital costs of low-carbon technologies compared to conventional fossil fuel fired generation plants. Costs to consumers is dependent on efficiency of incentive setting (£5/MWh error in incentive setting results in £4bn additional costs for consumers, NPV 2010-2030) ; incentives setting mechanisms such as auctioning can be used to mitigate these risks. Security of supply: capacity margins are lower than the baseline as a result of high penetration of low marginal cost plant (£200m).

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

Affordability: potentially results in excessive rents to low-carbon generators depending on carbon price foresight; lower foresight means that payments required to stimulate investment are higher than actually needed once carbon price rises in future. Barriers to entry: does not significantly affect barriers to entry. Durability: not robust to declining average wholesale electricity prices in future.

BENEFITS (£m)	Total Transition (Constant Price)	Years	Average Annual (excl. Transition) (Constant Price)	Total Benefit (Present Value)
Low				2,900
High				-
Best Estimate				9,900

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

Power sector in the UK will have to buy fewer EU ETS allowance saving around £6.0bn. In addition, non-carbon running costs (e.g. fuel) for generation plant will be around £3.8bn lower because of the lower running costs of low-carbon plants.

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

Affordability: results in more certainty for investors reducing financing costs
Efficiency: retains the link to the electricity price resulting in efficiency benefits
Practicality: premium payments are relatively straightforward to implement

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

Impact of low and high gas prices are presented to form the NPV range though both low and high gas price result in a lower NPV so a high estimate is not presented. The period of the modelling is between 2010 and 2030, therefore the analysis does not account for the benefits due to a rising carbon price after 2030. Under low gas price scenario and low-carbon price scenario, fails to achieved same level of decarbonisation in the 2030 (100gCO_2/KWh) assuming payments are not changed, though costs are lower for consumers as a result – if payments were increased to the meet the goal, then the NPV would be lower. Under high gas price scenario – overshoots on level of decarbonisation and costs for consumer are higher.

Impact on admin burden (AB) (£m):			Impact on policy cost savings (£m):	In scope
New AB:	AB savings:	Net:	Policy cost savings:	Yes/No

Summary: Analysis and Evidence — Decarbonisation: option 2

Description: Carbon price support: Renewables Obligation for incentivising investment in renewables. Investment in other low-carbon incentivised through the EU ETS and carbon price support, so that the overall carbon price achieves a predetermined level.

Price Base Year 2010	PV Base Year 2010	Time Period Years 20	Net Benefit (Present Value (PV)) (£m)		
			Low: -24,800	High: -	Best Estimate: -5, 800

COSTS (£m)	Total Transition (Constant Price)	Years	Average Annual (excl. Transition) (Constant Price)	Total Cost (Present Value)
Low				30,500
High				-
Best Estimate				21,600

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

Capital costs for the electricity generation sector increase by £17.5bn compared to the baseline because of the higher capital costs of low-carbon technologies compared to conventional fossil fuel fired generation plants. Running costs (excluding carbon) for generation plant will be £4.1bn higher as a result of switching from coal to gas generation.

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

Affordability: potentially results in excessive rents to low-carbon generators depending on carbon price foresight. Barriers to entry: does not significantly affect barriers to entry. Durability: not robust to declining average wholesale electricity prices in future.

BENEFITS (£m)	Total Transition (Constant Price)	Years	Average Annual (excl. Transition) (Constant Price)	Total Benefit (Present Value)
Low				5,700
High				-
Best Estimate				15,800

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

Power sector in the UK will have to buy fewer EU ETS allowance saving around £15.7bn. Security of supply: capacity margins are higher than the baseline as a result of high penetration of low marginal cost plant (£40m).

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

Affordability: results in more certainty for investors, reducing financing costs though this effect is small.
Efficiency: retains the link to the electricity price resulting in efficiency benefits
Transition issues: investment hiatus for renewables limited.
Potential for market manipulation is low.
Incentive setting: no requirement for government to set incentives by technology

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

Impact of low and high gas prices are presented to form the NPV range though both low and high gas price result in a lower NPV so a high estimate is not presented. The period of the modelling is between 2010 and 2030, therefore the analysis does not account for the benefits due to a rising carbon price after 2030. Under low carbon price scenario achieves same level of decarbonisation. Under low gas price scenario, fails to achieved same level of decarbonisation in the 2030, though costs are lower for consumers.
Under high gas price scenario – overshoots on level of decarbonisation .

Impact on admin burden (AB) (£m):			Impact on policy cost savings (£m):	In scope
New AB:	AB savings:	Net:	Policy cost savings:	Yes/No

Summary: Analysis and Evidence Decarbonisation: option 3

Description: Emission Performance Standard (EPS). Renewables Obligation for incentivising investment in renewables. EPS is used to restrict high carbon generation, thereby incentivising investment in low-carbon generation.

Price Base Year 2010	PV Base Year 2010	Time Period Years 20	Net Benefit (Present Value (PV)) (£m)		
			Low: -17,500	High: -5,700	Best Estimate: -7,700

COSTS (£m)	Total Transition (Constant Price)	Years	Average Annual (excl. Transition) (Constant Price)	Total Cost (Present Value)
Low				33,400
High				8,600
Best Estimate				20,900

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

Capital costs for the electricity generation sector increase by £16.5bn compared to the baseline because of the higher capital costs of low-carbon technologies compared to conventional fossil fuel fired generation plants. Running costs (excluding carbon) for generation plant will be £4.4bn higher as a result of switching from coal to gas generation.

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

Affordability: results in higher costs for consumers as the potential for excessive rents for producers is higher. Efficiency: generators are no longer fully exposed to long-term electricity price risk, which is one of a number of factors which helps prevent an (inefficient) over-supply of capacity in the market which transfers risk to government in terms of forecasting demand.

BENEFITS (£m)	Total Transition (Constant Price)	Years	Average Annual (excl. Transition) (Constant Price)	Total Benefit (Present Value)
Low				15,900
High				3,000
Best Estimate				13,200

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

Power sector in the UK will have to buy fewer EU ETS allowance saving around £13.1bn. Security of supply: capacity margins are higher than the baseline as a result of high penetration of low marginal cost plant (£90m).

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

Efficiency: retains the link to the electricity price resulting in efficiency benefits
Barriers to entry: does not affect barriers to entry
Transition issues: investment hiatus for renewables limited
Potential for market manipulation is low
Incentive setting: no requirement for Government to set incentives by technology
Benefits of innovation are not included.

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

Impact of low and high gas prices are presented to form the NPV range. The period of the modelling is between 2010 and 2030, therefore the analysis does not account for the benefits due to a rising carbon price after 2030. Under low gas price scenario and low carbon price scenario, fails to achieved same level of decarbonisation in the 2030, though costs are lower for consumers. Under high gas price scenario – overshoots on level of decarbonisation.

Impact on admin burden (AB) (£m):			Impact on policy cost savings (£m):	In scope
New AB:	AB savings:	Net:	Policy cost savings:	Yes/No

Summary: Analysis and Evidence — Decarbonisation: option 4

Description: Contracts for difference (CfD), on the wholesale electricity price, to incentivise investment in all forms of low-carbon generation

Price Base Year 2010	PV Base Year 2010	Time Period Years 20	Net Benefit (Present Value (PV)) (£m)		
			Low: -20,000	High: 1,700	Best Estimate: -3,970

COSTS (£m)	Total Transition (Constant Price)	Years	Average Annual (excl. Transition) (Constant Price)	Total Cost (Present Value)
Low				36,000
High				11,100
Best Estimate				24,100

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

Capital costs for the electricity generation sector increase by £24.1bn compared to the baseline because of the higher capital costs of low-carbon technologies compared to conventional fossil fuel fired generation plants. Costs to consumers is dependent on efficiency of incentive setting (£5/MWh error in incentive setting results in £4bn additional costs for consumers, NPV 2010-2030) ; incentives setting mechanisms such as auctioning can be used to mitigate these risks. Security of supply: capacity margins are lower than the baseline as a result of high penetration of low marginal cost plant (£300m).

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

CfD are complex mechanisms that may result in an investment hiatus and unintended consequences during implementation. Generators are no longer fully exposed to long-term electricity price risk, which is one of a number of factors which helps prevent an (inefficient) over-supply of capacity in the market

BENEFITS (£m)	Total Transition (Constant Price)	Years	Average Annual (excl. Transition) (Constant Price)	Total Benefit (Present Value)
Low				16,000
High				12,800
Best Estimate				20,200

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

Power sector in the UK will have to buy fewer EU ETS allowance saving around £9.6bn Running costs (excluding carbon) for generation plant will be around £10.8bn lower. Affordability: more certainty reduces costs for consumers as potential for excessive rents for producers is lower and financing costs are lower compared to premium payments.

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

Efficiency: retains the link to the electricity price resulting in efficiency benefits. Barriers to entry: reduces barriers to entry to some extent. Durability: robust to declining average wholesale electricity prices in future. Benefits of innovation are not included. Efficiency: generators are no longer fully exposed to long-term electricity price risk, which is one of a number of factors which helps prevent an (inefficient) over-supply of capacity in the market which transfers risk to government in terms of forecasting demand.

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

Impact of low and high gas prices are presented to form the NPV range. The period of the modelling is between 2010 and 2030, therefore the analysis does not account for the benefits due to a rising carbon price after 2030. In low gas price and low-carbon price scenarios, investment in low-carbon is not affected but higher cost for consumers relative to the premium payments as costs under premium payments are lower. In high gas price scenario, similar level of low-carbon investment is achieved but carbon emissions are increased in 2030 due to more coal generation. Lower costs for consumers relative premium payments.

Impact on admin burden (AB) (£m):			Impact on policy cost savings (£m):	In scope
New AB:	AB savings:	Net:	Policy cost savings:	Yes/No

Summary: Analysis and Evidence — Decarbonisation: option 5

Description: Fixed payments, separate to the wholesale electricity price, to all forms of low-carbon generation

Price Base Year 2010	PV Base Year 2010	Time Period Years 20	Net Benefit (Present Value (PV)) (£m)		
			Low: -19,900	**High: 1,000**	**Best Estimate: -3,900**

COSTS (£m)	**Total Transition** (Constant Price)	Years	**Average Annual** (excl. Transition) (Constant Price)	**Total Cost** (Present Value)
Low				**35,700**
High				**12,200**
Best Estimate				**24,000**

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

Capital costs for the electricity generation sector increase by £23.9bn compared to the baseline because of the higher capital costs of low-carbon technologies compared to conventional fossil fuel fired generation plants. Costs to consumers is dependent on efficiency of incentive setting (£5/MWh error in incentive setting results in £4bn additional costs for consumers, NPV 2010-2030). ; incentives setting mechanisms such as auctioning can be used to mitigate these risks. Security of supply: capacity margins are lower than the baseline as a result of high penetration of low marginal cost plant (£200m).

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

Efficiency: does not retain the link to the electricity price potentially resulting in additional costs. These were not modelled and are not included in these figures.
Practicality: fixed payments required additional mechanisms to feed electricity back into the market

BENEFITS (£m)	**Total Transition** (Constant Price)	Years	**Average Annual** (excl. Transition) (Constant Price)	**Total Benefit** (Present Value)
Low				**15,700**
High				**13,100**
Best Estimate				**20,000**

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

Power sector in the UK will have to buy fewer EU ETS allowances saving around £9.8bn. Running costs (excluding carbon) for generation plant will be around £10.5bn lower. Affordability: more certainty reduces costs for consumers as potential for excessive rents for producers is lower and financing costs are lower compared to premium payments.

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

Distributional: lower costs for consumer as potential for excessive rents for producers is lower and financing costs are lower
Barriers to entry: in principle removes barriers to entry. Benefits of innovation are not included. Efficiency: generators are no longer fully exposed to long-term electricity price risk, which is one of a number of factors which helps prevent an (inefficient) over-supply of capacity in the market which transfers risk to government in terms of forecasting demand.

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

Impact of low and high gas prices are presented to form the NPV range. The period of the modelling is between 2010 and 2030, therefore the analysis does not account for the benefits due to a rising carbon price after 2030. In low gas price and low-carbon price scenarios, investment in low-carbon is not affected but higher cost for consumers relative to the premium payments as costs under premium payments are lower. In high gas price scenario, similar level of low-carbon investment is achieved but carbon emissions are increased in 2030 due to more coal generation. Lower costs for consumers relative premium payments.

Impact on admin burden (AB) (£m):			**Impact on policy cost savings (£m):**	**In scope**
New AB:	**AB savings:**	**Net:**	**Policy cost savings:**	Yes/No

Enforcement, Implementation and Wider Impacts

What is the geographic coverage of the policy/option?			GB		
From what date will the policy be implemented?			tbc in White Paper (WP)		
Which organisation(s) will enforce the policy?			tbc in White Paper		
What is the annual change in enforcement cost (£m)?			tbc in White Paper		
Does enforcement comply with Hampton principles?			Yes to be considered in WP		
Does implementation go beyond minimum EU requirements?			No		
What is the CO_2 equivalent change in greenhouse gas emissions? (Million tonnes CO_2 equivalent)			**Traded:** n/a		**Non-traded:** n/a
Does the proposal have an impact on competition?			Yes		
What proportion (%) of Total PV costs/benefits is directly attributable to primary legislation, if applicable?			**Costs:** n/a		**Benefits:** n/a
Annual cost (£m) per organisation (excl. Transition) (Constant Price)	**Micro**	**< 20**	**Small**	**Medium**	**Large**
Are any of these organisations exempt?	No	No	No	No	No

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	p. 114
Economic impacts		
Competition Competition Assessment Impact Test guidance	Yes	p. 81
Small firms Small Firms Impact Test guidance	No	p. 83
Environmental impacts		
Greenhouse gas assessment Greenhouse Gas Assessment Impact Test guidance	Yes	p.66
Wider environmental issues Wider Environmental Issues Impact Test guidance	Yes	p. 76
Social impacts		
Health and well-being Health and Well-being Impact Test guidance	Yes	p. 76
Human rights Human Rights Impact Test guidance	No	p. 114
Justice system Justice Impact Test guidance	No	p. 114
Rural proofing Rural Proofing Impact Test guidance	No	p. 92
Sustainable development Sustainable Development Impact Test guidance	No	

[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) – Notes

Use this space to set out the relevant references, evidence, analysis and detailed narrative from which you have generated your policy options or proposal. Please fill in **References** section.

References

Include the links to relevant legislation and publications, such as public impact assessment of earlier stages (e.g. Consultation, Final, Enactment).

No.	Legislation or publication
	Please see footnotes in the main body of the IA

\+ Add another row

Evidence Base

Ensure that the information in this section provides clear evidence of the information provided in the summary pages of this form (recommended maximum of 30 pages). Complete the **Annual profile of monetised costs and benefits** (transition and recurring) below over the life of the preferred policy (use the spreadsheet attached if the period is longer than 10 years).

The spreadsheet also contains an emission changes table that you will need to fill in if your measure has an impact on greenhouse gas emissions.

Annual profile of monetised costs and benefits* - (£m) constant prices

	Y_0	Y_1	Y_2	Y_3	Y_4	Y_5	Y_6	Y_7	Y_8	Y_9
Transition costs										
Annual recurring cost										
Total annual costs										
Transition benefits										
Annual recurring benefits										
Total annual benefits										

* For non-monetised benefits please see summary pages and main evidence base section

Evidence Base (for summary sheets)

Summary and conclusions

Challenges facing the electricity market

Our analysis has identified two key challenges for the current electricity market arrangements: incentivising investment in low carbon generation and maintaining security of supply.

Incentivising investment in low carbon generation

Whilst the UK is on target to reduce its greenhouse emissions in 2020 by 34% by 1990, 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 2020s, particularly if it is to play its part in decarbonising the heat and transport sectors in the 2030s and beyond.

This transition to a low-carbon system presents significant challenges for the current market arrangements. Under these arrangements there is a degree of revenue uncertainty that may not be acceptable for high capital cost, non-price setting plant, along with investor uncertainty about the future carbon price. It is possible that for some technologies, the market will find ways of managing some elements of this 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. However without government intervention, various commentators including the Committee on Climate Change (CCC) suggest that the UK will not be on the right decarbonisation path to 2050. Their analysis suggests the need for 30-40GW of low-carbon capacity to be built during the 2020s to replace ageing capacity and meet demand growth. The CCC argues that current market arrangements are highly unlikely to bring forward sufficient investment.[2]

Modelling for the EMR project by Redpoint Energy suggests that the emissions intensity in 2030 under a ‘do nothing’ scenario will be around 200gCO_2/kWh compared to an intensity of around 100gCO_2/kWh recommended by the CCC in 2009[3] and recently revised down to 50gCO_2/kWh in their fourth carbon budget report (published December 7, 2010)

Maintaining security of supply

Our analysis suggests that, towards the end of this decade, the capacity margin (the margin of excess electricity generation capacity over peak demand) is likely to fall to a level that would lead to greater risks to security of the GB’s electricity supply, and remain around this level. This is due to a number of existing market failures and imperfections whose effect becomes exacerbated as levels of low marginal cost, low-carbon generation increase. They mean that the return to flexible resources may be too low and too uncertain, leading to too little investment. While vertical integration or higher levels of contracting between independent generators and suppliers may mitigate some of this uncertainty, the identified market failures and imperfections suggest that current low levels of long-term contracting will continue.

Therefore this IA has considered options for incentivising investment in low-carbon generation along with options to ensure that the capacity margin remains adequate over the next two decades .

Analytical approach

[2] http://www.theccc.org.uk/reports/fourth-carbon-budget
[3] CCC, *Meeting carbon budgets - the need for a step change*, October 2009

The modelling consisted of establishing a indicative level of decarbonisation in 2030 and assessing the differential costs and benefits of meeting that target under the different options for low carbon support, compared to a business as usual baseline in which this target is not met. There is currently no Government target for greenhouse gas or carbon emission reductions in the electricity sector. However for the purposes of this project, we used an indicative goal of 100gCO_2/kWh in 2030 to compare the impacts of the different options. This is derived from DECC's published long term carbon values[4], which estimates the global carbon price in 2030 consistent with a 2C emissions trajectory. If investors had perfect foresight of this price, they would decarbonise to around 100gCO_2/kWh in 2030. In our judgement, this provides a reasonable scenario against which to test the options for reform, since the DECC carbon values represent a least cost path to global decarbonisation. 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. As noted, the CCC have recently suggested a lower level for 2030 would be appropriate (50gCO_2/kWh in 2030), which would have a significant impact on the cost benefit analysis (increasing the NPV of the options presented).

As with any modelling work the outputs are highly dependent on the input assumptions and this is particularly true here. Beyond the decarbonisation level in 2030 already discussed, other key assumptions include the degree of foresight investors have over future increases in the carbon price along with the impact that particular options have on willingness to invest and the rate of return required for doing so. Assumptions about the value placed on ensuring uninterrupted electricity supplies and the carbon price are also critical in driving in the overall costs and benefits to society. If these values change by relatively small amounts the overall benefits of the reforms can move from being positive to negative or vice versa. There are also other benefits that are not captured in the modelling, such as those resulting from innovation.

The overall results show a negative NPV for all the decarbonisation options considered. This reflects a number of factors, including potential benefits that are not monetised such as innovation benefits, and the fact that the modelling only covered the period up to 2030. Covering a longer period would likely result in positive NPVs for the options, since post 2030, DECC carbon values (and hence the benefits of low carbon generation) increase considerably. Assumptions around fossil fuel prices and values of lost load also affect the overall NPVs considerably. The importance of assumptions made for the overall conclusions is highlighted at the end of this summary. Overall, the modelling should be seen as a way of providing insights into the comparative impacts of reform options in what is a very complex system rather than predictions of the future.

Options for incentivising investment in low-carbon generation

Five different options for driving investment in low-carbon generation have been considered: premium payments, carbon price support (CPS), an emissions performance standard (EPS), contracts for difference (CfD) and fixed payments. These mechanisms have been considered both in terms of how they drive investment when used in isolation but also the costs and benefits of using some of them in combination.

This analysis suggests that, when used in isolation, all of these options are capable of driving investment in low-carbon generation to a level that is consistent with longer term decarbonisation goals. They do however perform differently in terms of meeting DECC's main objectives: they provide a different level of certainty that decarbonisation goals will be met and their impacts on costs for consumers vary. There is no significant difference between the options in terms of how they interact with security of supply options; this is because they are targeting different types of generation.

[4] DECC, *Carbon Valuation in UK Policy Appraisal: A Revised Approach,* July 2009

- **Decarbonisation**: The modelling suggests that investment in low-carbon generation happens earlier with fixed payments and contracts for difference (CfD) given the certainty they provide for capital-intensive low-carbon projects. Fixed payments and CfD also provide more certainty that carbon targets will be met as they are more robust to both low gas prices and low carbon price scenarios, because decisions to invest in low-carbon generation are largely unaffected by changes in the electricity price. Premium payments would need to be increased (for new installations) to meet decarbonisation targets in low gas or carbon price scenarios, as would levels of carbon price support.

- **Affordability:** premium payments, fixed payments and CfD will result in lower financing costs than the base line, and fixed payments and CfD result in lower financing costs than premium payments. The certainty that leads to lower financing costs for fixed payment and CfD leads to lower costs for consumers under fixed payments and CfD than the other three mechanisms. Premium payments result in higher costs for consumers largely due to lower reduction in financing costs and due to investors' lack of foresight of a rising carbon price, with associated excessive rents for producers where electricity prices subsequently rise. However, by retaining full exposure to market incentives to operate efficiently it offers some benefits which are not reflected in the modelling and would offset some of these additional costs. CPS and EPS also both result in relatively high costs for consumers. On average costs for consumers would be around 2% lower under CfD and fixed payments than the other options, assuming a similar technology mix.

The options also have different impacts on: overall costs to society and efficiency; how they affect barriers to entry and therefore how likely they are to attract additional investment into the sector; how durable they are; how well they combine with other mechanisms; and how easy they are to implement.

- **Overall costs to society**: the modelling suggests that fixed payments and CfD are preferable in terms of net welfare as they result in lower costs of capital given the higher level of investor certainty provided. Premium payments, CPS and EPS (when used in isolation) are more costly in terms of net welfare as they do not provide the same degree of certainty to investors. In net present value terms (NPV), overall cost to society under premium payments would be approximately £4bn higher than under fixed payments and CfD (ie an NPV of around -£8bn, 2010 to 2030, for premium payment compared to an NPV of -£4bn for fixed payments and CfD). In a high demand scenario, with demand in 2030 30% higher than in 2010, both CfD and fixed payments have a positive NPV (around £6bn over the period).

- **Efficiency**: Fixed payments remove exposure to electricity price and offtake risks (the risk of not being able to sell the electricity you produce), resulting in loss of market efficiency benefits. Whilst these benefits are relatively small for certain technologies such as wind, they may be more important in the future and are potentially more significant for other technologies such as nuclear and CCS. Premium payments, CfD, CPS and EPS all retain this link to different degrees, in particular CfDs are not exposed to long-term electricity price risk.

- **Barriers to entry:** Fixed payments should reduce barriers to entry significantly as they remove both price risk and offtake risk from generators. Premium payments, CPS and EPS do not significantly reduce the barriers to entry when compared to the current market arrangements – although to the extent that they reduce the cost of capital they may facilitate more entry. CfD reduce barriers to entry though this effect may be limited as offtake risk and imbalance risk is retained by generators. Fixed payments therefore probably offer the greatest relative potential to attract new investors. Additional investment is likely to be required as this analysis suggests that raising the required finance will prove a challenge and could stretch the Big 6 utilities to their maximum.

- **Durability**: fixed payments and CfD are more robust to a high penetration of wind and nuclear power (and other low marginal cost plant), which pulls down the average electricity price, than the other three options that all depend on the wholesale price for their revenues. Modelling suggests this starts to become an issue in the late 2020s.

- **Practicality**: there are significant practical challenges in implementing these options. These challenges are greatest with fixed payments where a separate mechanism would be required to feed electricity procured back into the market. These challenges are also significant for a CfD, which requires a robust index price to settle the contract against. Premium payments, CPS and EPS would be simpler to implement as they are more closely based on the current market arrangements. Any move from the current support mechanism for renewables could have complex implementation issues due to the extent that the RO is devolved to Scotland and Northern Ireland. There is also a risk of a delay in investment, particularly for renewables while investors learn to understand the new mechanism. There is less risk of investment delay with premium payments or CPS than there would be with fixed payments or CfD.

- **Coherence**: premium payments combine well with CPS: payments can be reduced as the wholesale electricity price is higher. CPS provides more revenue certainty than premium payments alone, which reduces financing costs, though the impact is relatively small.. Payments to low-carbon generation under fixed payments do not change with the introduction of CPS as there is no link to the wholesale electricity price. Similarly total payments to low-carbon generation under CfD do not change with the introduction of CPS; however CPS does mean that generators receive a higher proportion of their income from the wholesale price and are therefore not as exposed to wholesale price fluctuations before the CfD is settled. The impact of combining premium payments, CfD and fixed payments with different types of capacity mechanism were considered in the analysis, which demonstrated that the impacts of the two main types of capacity mechanisms (targeted and market-wide) were not significantly altered by the choice of decarbonisation mechanism.

Overall, when judged against these criteria, CfD appear to perform better as they: provide certainty that decarbonisation goals will be achieved under various different scenarios, including low gas prices; result in lower costs of capital that reduce financing costs, given the certainty that they provide which also limits the potential for excessive rents. As a mechanism for driving sustained investment in low-carbon generation, CfD are also more robust against a world of declining average wholesale prices, likely to be particularly significant towards the end of the 2020s. Unlike fixed payments, CfD retain the link to the signals provided by the short-term electricity price and the key efficiency benefits that stem from this. CfD are therefore the preferred option as the core mechanism for driving low-carbon investment.

Options for ensuring electricity security of supply

We have considered the impact of improving the existing market arrangements. This will have a beneficial effect on security of supply. However, this does not fully tackle the issue of high levels of revenue uncertainty for flexible resources and, alone, is likely to be insufficient. We have therefore also considered the implementation of a capacity mechanism.

A capacity mechanism creates an explicit value for capacity (a capacity payment is given to resource, including both the supply side and the demand side, for providing available capacity) and so allows a specific level of capacity to be targeted. There are many different types of mechanism. This IA considers them in two broad groups: market-wide capacity mechanisms, that pay capacity payments to all resources, and targeted capacity mechanisms, that pay capacity payments to some resources. They can be seen as restoring the element of contracting that is missing in the market.

The two groups of capacity mechanism would both improve security of supply and are broadly similar in terms of their overall costs to society (net present value, NPV). The NPV values are useful for comparing the different options, but are not meaningful in absolute terms. This is because they are primarily determined by the level of margin targeted and the the value ascribed to the security of supply benefit (the value of lost load, VOLL). The VOLL is highly uncertain and a range is used in the analysis. If the upper end of the range been taken the NPV would be positive. In addition, there are external benefits to the economy and social welfare of security of supply which have not been quantified in the Value of Lost Load used. This is because they are difficult to value. A target margin of 10% was chosen but, had a lower level been used, the NPV would have been higher (as less additional generation would need to be supported). If implemented, the choice of target would be better based on the chosen VOLL in order to ensure that the policy was beneficial and had a positive NPV. Further benefits, in particular enabling the uptake of demand side resources, are also not included.

A market-wide mechanism avoids potential market distortion, but is a considerable intervention in the market. This leads to a significant risk of unintended consequences (including gaming), market disruption and a lengthy implementation phase. Further, by paying all resource the same there is a risk that the 'right' type of flexible resource is not incentivised and that windfalls are given to some generators. A targeted capacity mechanism is a smaller intervention and so these risks are reduced. However, there is a greater risk of market distortion, in particular that too much resource enters the targeted mechanism because this is seen as more attractive. This issue has been addressed in other similar interventions, such as the Short Term Operating Reserve and Swedish Peak Load Tender. On balance, the Government sees the targeted capacity mechanism as more attractive.

Packages of options

CfD have been combined with CPS, a targeted capacity mechanism and a targeted EPS (set at a level that prevents the development of new unabated coal) to form the preferred package. A targeted EPS is included as it sends a clear regulatory signal to investors in electricity generation, to support the economic signals from the carbon price. It builds on the Government's current policy that developers must demonstrate CCS on a proportion of a coal-fired power stations capacity, and provides a regime under which plant will be expected to operate. Unlike the carbon price, a targeted EPS is not affected by movements in fossil fuel prices and it is therefore potentially more robust in a high fossil fuel price scenario and provides an important backstop.

CPS is included as it sends important signals in terms of the development and operation of unabated fossil fuel plant which in turn sends important signals to investors in low-carbon generation. In addition when it is combined with CfD, CPS means that generators receive a higher proportion of their income from the wholesale price and are therefore not as exposed to the wholesale price fluctuations before the CfD is settled. When combined with other decarbonisation options, the overall carbon price targeted by carbon price support does not need to be as high. This minimises concerns about a steep increase in the carbon price to 2020 and the impacts on existing generators (both fossil-fuel and low-carbon).

Assumptions made and design questions

It is important to note that the conclusions in the consultation document and this impact assessment on the preferred package are based on a number of assumptions both relating to the underlying evidence base and the practicability of certain policy options. While we believe the conclusions we have reached are reasonable on the basis of the evidence available to us, we are keen to use the consultation process to draw on the views of experts and stakeholders to test the robustness of our assumptions. We would highlight the following assumptions in particular:

- That investors are not likely to incorporate a rising carbon price into their investment decisions and that investors are likely to discount at least some of the value of a carbon price support mechanism implemented through the tax system.
- That costs of capital would be lower with a CfD and fixed payment than with a premium payment
- That maintaining the exposure to the wholesale electricity provides important market discipline and efficiency, even for low carbon generators, and that this could not be effectively reproduced through a contract.
- That liquidity of the market can be improved so that off-take risk for low-carbon independent generators is manageable.
- That the benefits of any form of FIT (premium, fixed or CfD) and of a targeted capacity mechanism would not be forthcoming in the market without further intervention, for example, because of a lack of contracting or because high levels of vertical integration would be necessary.

In addition we have identified, a number of key factors for success of the package. A more detailed discussion on implementation issues is given in Chapter 6 of the consultation document. The conclusions are then based on the following design assumptions:

- That there is a suitable reference price for the CfD
- That the strike price in the CfD can be set effectively e.g. through a competitive auction.
- That the CfD can be designed to avoid perverse incentives to manipulate the electricity price
- That both the CfD and targeted capacity mechanism can be designed to avoid incentivising overly high levels of build.
- That the targeted capacity mechanism can be designed to avoid perverse incentives and contract effectively so that the intervention remains targeted and does not significantly distort the rest of the market
- That cash-out can be reformed so that investment signals in the remainder of the market are effective.
- That introducing the EPS described, while providing a valuable back-stop, would not have a significant impact on the market.

The consultation document invites questions on the validity of these assumptions and the extent to which this proposed package design is achievable.

Given these issues around detailed design and implementation, a premium payment package (premium payments, CPS, targeted capacity mechanism and EPS) is considered as a credible alternative package in the consultation document.

Part A – Introduction and Background

1.0 Introduction

1. The aim of the Electricity Market Reform (EMR) project is to assess options for future market arrangements against DECC's objectives of decarbonisation, security of supply and cost-effectiveness. The aim of this impact assessment (IA) is to consider the impacts of the options for reform. It is broken down into two main parts:
   - Part B: Options for ensuring electricity security of supply
   - Part C: Options for incentivising investment in low-carbon generation

2. The detailed options for carbon price support are the subject of a separate consultation and IA led by HM Treasury and HMRC.

2.0 Background

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

   - Delivered almost 30GW of gas plant currently in operation[5]
   - Maintained an adequate capacity margin.
   - Given electricity prices that have been comparatively low and fairly responsive to movements in fuel costs.
   - Supported the deployment of increasing amounts of renewables through the renewables obligation (RO)
   - Reduced greenhouse gas emissions somewhat, mainly through switching from coal to gas.

4. However, in the coming decades the UK electricity market faces new challenges which will require reform to the current market arrangements to ensure that the Government meets its objectives of ensuring reliable, low-carbon and affordable supplies of electricity.

5. The Committee on Climate Change advise that the UK power sector should reduce its average carbon emissions from current levels of 500gCO_2/kWh to 50gCO_2/kWh by 2030[6]. Further to this, around 30% of our electricity in 2020 needs to come from renewable sources to meet our legally binding target for renewable energy. This will require large capital investments in new renewable and low-carbon sources of electricity generation assets, as well as investments in the associated electricity networks.

6. In addition to this, the retirement of around a quarter of our existing power plants by 2020, due to stringent air quality and EU regulations on plant emissions as well as an aging nuclear fleet, imposes challenges to security of supply . It is estimated that the UK will need to replace around a quarter of our existing plants by 2020.

7. Overall, we estimate that the UK will need to invest up to around £110bn in new electricity generation, transmission and distribution assets by 2020, in a way that minimises bill increases for consumers.

8. Further to this, decarbonisation of the UK economy through electrification of heat and transport would increase the total demand for electricity, posing additional challenges for security of supply. Additional demand from the heat and transport sectors, despite

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[5] DECC, Digest of United Kingdom energy statistics
[6] Committee on Climate Change November 2010

improvements in energy efficiency, means that the supply of electricity may need to double by 2050.

9. Meeting these challenges will not only require the construction of new generating plant to supply electricity, but also the integration of measures to reduce demand both permanently, by increasing energy efficiency, and dynamically, by increasing the ability of demand to flexibly vary in response to price signals. The Government is therefore consulting on a package of options that will reform the electricity market to ensure our energy and climate goals are met.

Part B – Options for ensuring electricity security of supply

1 Introduction

1. This part of the IA considers the impacts of the options for ensuring electricity security of supply:
   - Section 2: Rationale for government intervention
   - Section 3: Description and characteristics of policy options
   - Section 4: Modelling approaches and caveats
   - Section 5: Relative comparisons between the capacity mechanism options
   - Section 6: Costs and benefits of the options when used in isolation, in terms of economic efficiency, distributional impacts, barriers to entry and competition and security of supply, market distortion transitional costs, wider macroeconomic effects, impacts on business.
   - Section 7: Other risks and costs, including:
     - Administrative costs
     - Risks from system gaming (market manipulation)
     - Risks of double payments
     - Risks from unintended consequences
   - Section 8: Summary of costs and benefits
   - Section 9: Preferred policy option and rationale

2 Rationale for government intervention

2.1 Introduction

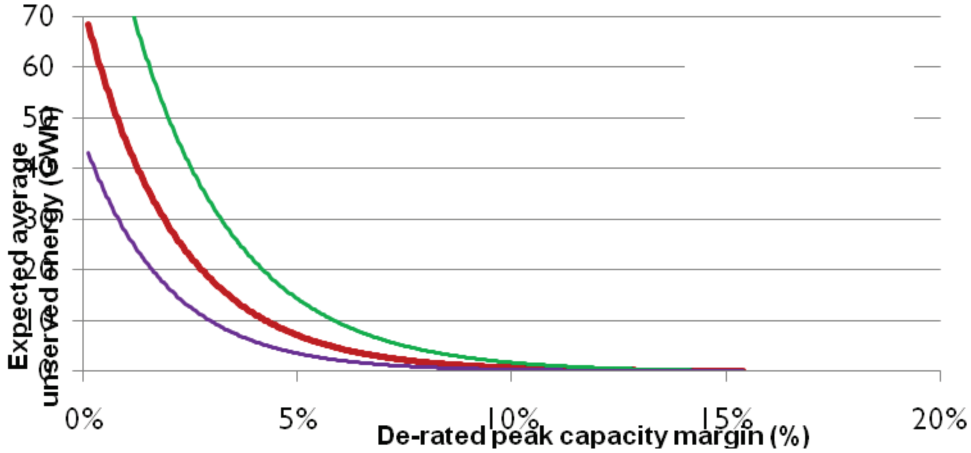
2. To provide secure electricity supplies, supply and demand must balance at every point in time. In the GB electricity system generators and suppliers[7] are incentivised to ensure this by the requirement to pay imbalance charges (the cash-out price) if at 'gate closure' (one hour before the dispatch 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), who is National Grid) takes responsibility for ensuring the system as a whole remains in balance. As part of this the System Operator gives capacity payments to a small amount of generation or demand side response to be available for this residual balancing role. Annex 1 gives an introduction to the current arrangements.

3. One indicator of security of supply is the expected energy unserved (EEU), which is a combination of the likelihood of an involuntarily interruption and the likely size. A proxy for this is the capacity margin, the % by which total available de-rated generating capacity exceeds peak demand. The relationship is illustrated by Figure B1. EEU includes both energy unserved because of voltage reduction[8] and that due to outages. Some context can be gained from looking at the current EEU from distribution level faults e.g. trees falling on power lines, which are around 12GWh of outages[9]. The EEU from generation

[7] Generators are only exposed to outages and not exposed otherwise, since they can always lower their final physical notifications. Suppliers however are more exposed to being short if the system is short, since they cannot trade out of a position.
[8] 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.
[9] Dynamics of GB generation investment, Redpoint (2007)

related problems has been near to zero in recent years. This compares to approximately 400,000GWh of electricity supplied in 2009[10].

Figure B1: Effect on expected energy unserved as de-rated capacity margin increases.



* Chart based on Redpoint simulations. A line of best fit based on regression analysis is shown together with error bars 1 and 2 showing an illustrative range around the fit parameters.

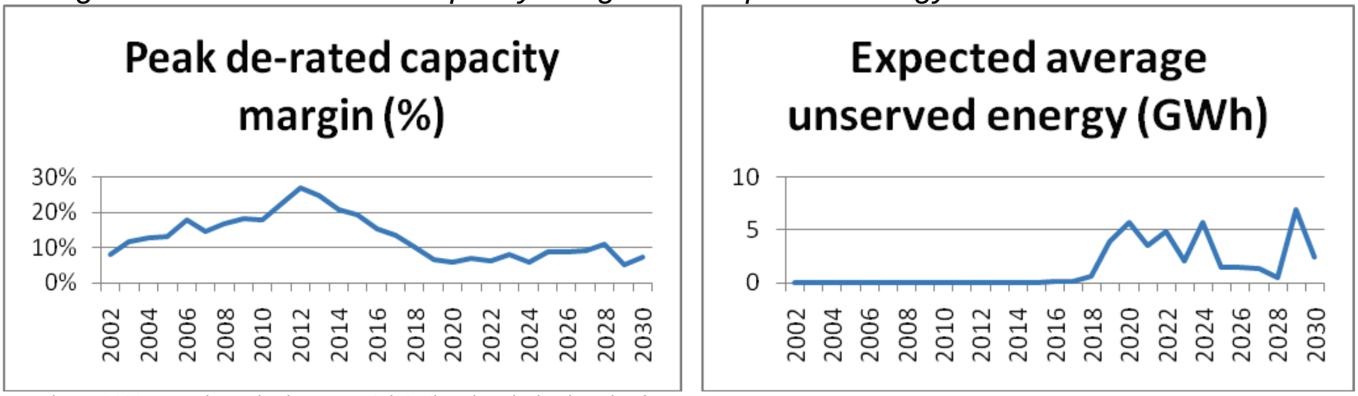
4. There is a trade off between the cost of new capacity and security of supply. Estimates of the optimal level of security (level of expected involuntary interruptions that minimises the overall costs to society – also known as the socially optimal level) are highly uncertain and very dependent on estimates assigned to the consumer valuations of supply disruption or lost load (VOLL - value of lost load). Some estimated ranges have been assigned between £10,000-30,000/MWh[11]. Once we take into account the full benefits to society of security of supply, the upper part of the range is likely to be higher. These benefits include the attractiveness of the UK as a location for investment. Using the above ranges for VOLL and comparing to the long run cost of a new entrant peaking plant (OCGT)[12] tentative estimates suggest that an optimal range could be around 0.5-4GWh per year for EEU or a de-rated capacity margin of 8-12%. Noting that there is greater uncertainty around the upper bound. Above this level, however, there are significant diminishing marginal returns in terms of additional security offered by adding additional capacity.

2.2 The case for intervention

5. Current margins (around 18% in 2010 and expected to be up to 27% in 2012) are higher than the historic average (2002- 2009 average was 10-18%) as a result of the combination of lower electricity demand as a consequence of the economic slowdown as well as the market identifying a need for new capacity in anticipation of closures from 2016 onwards. Externally commissioned modelling by Redpoint (see Figure B2 below) suggests that when margins level out they will be lower than historic margins (around 5-11% between 2020-2030, with an average of 8%) and in some instances lower than even the bottom end of estimates of optimal and with an EEU of around 0.5 -7GWh[13]

[10] DECC (2010) Digest of United Kingdom Energy Statistics
[11] Based on Redpoint assumptions and Oxera (What is the optimal level of electricity supply security, (2005)
[12] £60/kW/year, Redpoint assumptions based on DECC Mott Mcdonald
[13] This is based on regression analysis and a line of best fit, however with a 5-11% margin the EEU range could be wider.

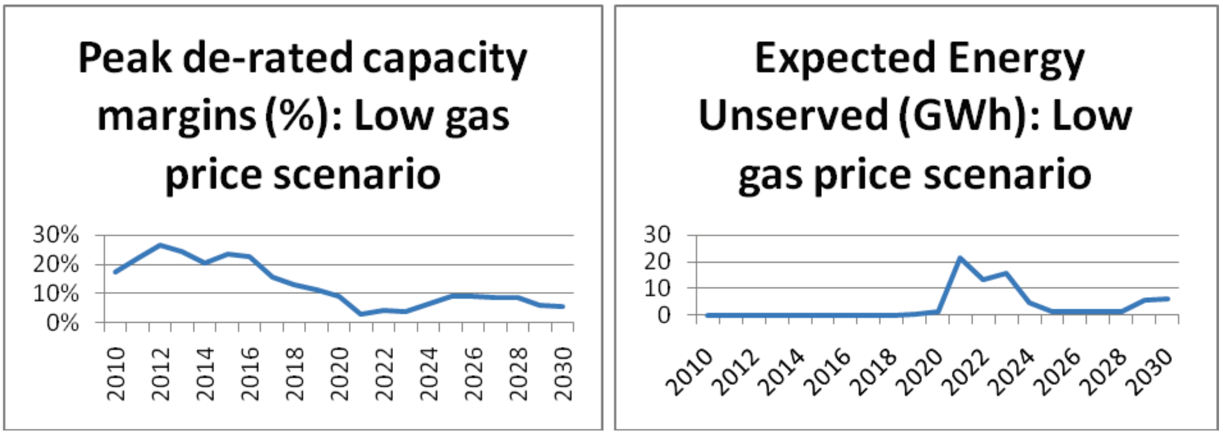
Figure B2: Peak de-rated capacity margin and expected energy unserved to 2030



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

6. The Redpoint analysis suggests expected average EEU of around 1GW lasting no more than 3 hours. We expect that much of this EEU could be mitigated through voltage reduction rather than actual power cuts. However, there are risks that some outages could be larger than the average and could not be mitigated against through such measures leading to risks of involuntary demand reductions. Furthermore the modelling suggests that in some simulations where gas prices remain low there are risks from higher levels of expected energy unserved, as less plant is built and/or more retires since plant revenues are lower. In some years these levels of EEU would pose significant risks of power cuts and would be outside the ranges that could be deemed as socially optimal.

Figure B3: Peak de-rated capacity margin and expected energy unserved with low gas prices



7. In addition to the modelling, the discussion below provides t a qualitative assessment as to whether, in principle, the market is likely to deliver a level of security of supply that is consistent with the optimal margin range. We conclude that there are a number of market failures and imperfections that are likely to pose risks to future levels of electricity security of supply, resulting in weak signals for investments in new (flexible) capacity either because:
   (i) the wholesale electricity price will not rise high enough;
   (ii) price will be too uncertain and unmanageable for generators; or
   (iii) the effects of investment cycles will lead to low margins in certain years.

2.2.1 Peak price too low

8. Wholesale prices may not rise high enough to reimburse generators and ensure security of supply for a number of reasons:

- The cash-out price is too low because it does not fully include all the costs of the actions taken by the SO in addressing an imbalance, as described in Ofgem's Project Discovery[14].
- The perceived risk that government will prevent peak prices rising as high as necessary, which has the same impact as the price actually being too low[15]
- The lack of significant electricity trading (liquidity), especially in forward markets, which means that longer-term contracts and trades may not fully reflect the cash-out price as described in Ofgem's discussion paper on liquidity[16].

2.2.2 Management of peak price uncertainty

9. Markets are often effective in dealing with price uncertainty through long term contracting. However, there are a number of reasons why, in the wholesale electricity market, levels of long term contracting may be too low to enable 'optimal' levels of security of supply:
   - A lack of liquidity in forward markets[17]
   - For suppliers, the risk of a reduced customer base is greater than the risk of high future prices. As a result, suppliers' decisions are based on much shorter time-scales than generators' investment decisions.[18]
   - Suppliers may anticipate government intervention if margins are tight and so not fully hedge against it.

2.2.3 Investment cycle

10. The investment cycle may also have a negative impact on security of supply: an investment cycle results from the herding behaviour of investors in their response to investment signals coupled with the inherently lumpy nature of generation (power stations are relatively large), meaning that margins will be particularly low in some years[19]. This is a feature demonstrated by other markets e.g. property development market (known as the cobweb theory[20]).

2.3 *Why the problems are likely to get bigger in the future*

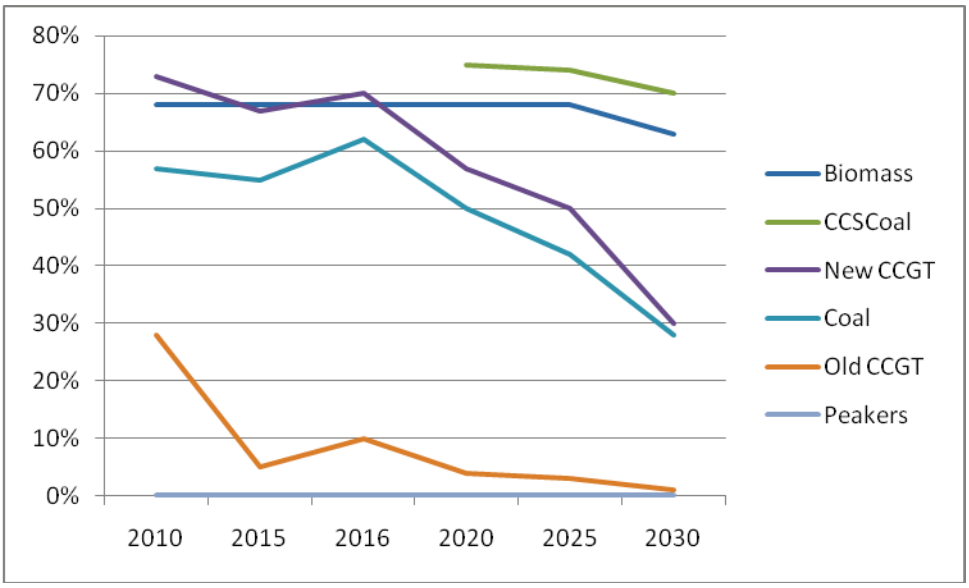
11. These failures and imperfections will have a greater effect when there are significant amounts of low-carbon intermittent generation. This is because it will be necessary to have flexible generation to meet demand when, for example, the wind isn't blowing. This flexible generation will need to cover its costs by running only a small fraction of the time and so will be reliant on prices being sufficiently high at these times.

12. Figure A4 below shows the impact of increasing wind generation on the running hours or load factor of flexible power stations: Combined cycle gas turbines (CCGTs), which are the standard gas power stations built today and coal plant, both of which provide mid-merit

[14] Ofgem Project Discovery, Options for delivering secure and sustainable energy supplies, Consultation, 3 February 2010 (http://www.ofgem.gov.uk/markets/whlmkts/discovery/Documents1/Project_Discovery_FebConDoc_FINAL.pdf)
[15] Op cit, Ofgem project discovery (2010)
[16] Ofgem Liquidity in the GB wholesale energy markets, Discussion paper, 8 June 2009 (http://www.ofgem.gov.uk/Markets/WhlMkts/CompandEff/Documents1/Liquidity%20in%20the%20GB%20wholesale%20energy%20markets.pdf0.
[17] Why we need to fix our broken electricity market, special report, Poyry (2008)
[18] Comparison on Long Term Contracts and vertical integration in decentralised electricity markets, Meade et al (2008)
[19] Op cit, Redpoint (2007)
[20] N.Kaldor, "The Cobweb Theorem", Quarterly Journal of Economics, Vol. 52, No.2 (Feb 1938) p.255-280

flexibility. It illustrates the impact of a 30% wind penetration in 2020 and 42% in 2030. A corollary to the reduction in running hours is that in the future these plants would need to be able capture periods of higher electricity prices in order to make the same economic return on their investments.

Figure B4: Annual Plant Load factors in GB[21]



13. However even if peak prices are sufficient, the revenue uncertainty will be large, particularly because there is uncertainty that investors would be able to capture those high prices as they occur. This makes investments in flexible generation increasingly higher risk and less attractive, especially compared with low-carbon options where there is active Government policy to reduce investment risks. Moreover in the case of peaking generation (such as OCGT) which runs at low load factors, the revenue from the wholesale market – even if prices are very high, is quite small. Poyry analysis finds that the returns to peaking plant is not sufficient to make investments in them viable[22]. In addition, from the point of view of a developer, investing in peaking generation could be particularly high-risk, with much greater uncertainty over future revenue than is the case for a conventional baseload plant.

14. Variability and uncertainty over load factors will also increase costs for plants, further adding to the increasingly difficult investment environment,since increased cycling of a plant raises maintenance costs, places more stress on a plant and raises fuel costs (as it will be running below its efficient level more often). In addition to this, the uncertainty over when the plant will be dispatched creates a significant logistical challenge in planning maintenance and staff availability, which will also translate into higher costs, investors will anticipate these effects even in the next decade and beyond.

2.4 Reasons for taking actions in the next few years

[21] Poyry, *Impact of intermittency, how wind variability could change the face of the British and Irish electricity markets, Summary report*, July 2009
[22] Poyry, *Implications of intermittency – a multi-client study*, 2009

15. In the next few years, market participants will be faced with decisions regarding the Industrial Emissions Directive (IED) [23] which comes into effect in 2016 in addition to their decisions on new build. In order to give clear signals to generation companies of the market structure they will face going forward it will be important to action any security of supply measures in time to influence the decisions of market participants. Decisions on the IED are likely to be made by the end of 2012. Moreover, in designing these interventions now, the Government needs to ensure a co-coordinated approach in our decarbonisation policies and institutional arrangements.

2.5 Conclusions

16. In conclusion, the quantitative analysis suggests that margins towards the end of the decade and in the 2020s will be somewhat lower than historical margins and in instances below the range that could be deemed to be socially optimal. The Government's consideration of market failures and imperfections further supports this finding. Moreover greater amounts of low-carbon generation on the system whilst provides more capacity, equally means that revenue risks for back-up plants that are necessary to ensure security of supply will increase as they face very low load factors and uncertainty over being able to capture peaking prices. These will be exacerbated by the market imperfections discussed. In addition generators need to be able to make key choices in the next few years. All these issues taken collectively provides a rationale for government intervention.

3. Description of policy options

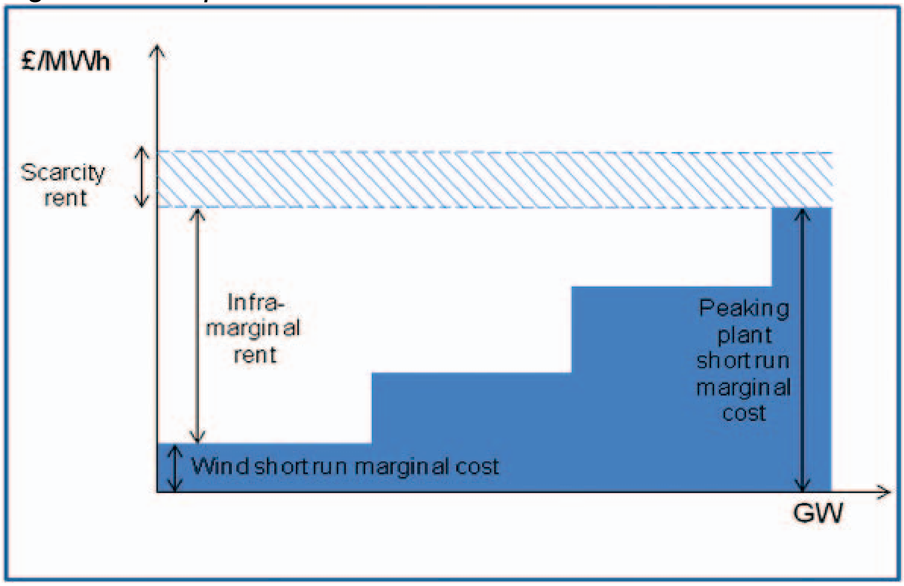
17. Since 2001, the GB electricity market has been an 'energy-only' market[24]: generators only receive revenue if they produce and sell electricity (apart from revenue from providing reserve and other services to the System Operator). Internationally, there are other markets in which some or all generators explicitly receive revenue both for the electricity they sell and the capacity they make available to the system through some form of 'capacity mechanism'. In some markets, additional resource is provided by reducing demand, known as demand-side management. This can be achieved either through overall reduction of demand through energy efficiency measures or through reduction of demand at times of tightness and/or shifting to periods of energy surplus, this is known as demand-side response (DSR).

18. In an 'energy-and-capacity' market a capacity mechanism provides an explicit payment for capacity which replaces volatile and uncertain scarcity rents with a constant payment (set within the blue hatched area in Figure B5 below). More detail on 'scarcity rents' is in Annex 1. The incentive can also be set so that a higher (and smoother) capacity margin can be obtained than the market would have delivered.

[23] Under the IED, all combustion plant permitted before 2002 will have to make a decision as to whether to opt-out of the IED by the end of 2013. If they opt-out they will have to close at the end of 2023.

[24] In an energy only market all electricity generators are expected bid at their short run marginal cost (SRMC), provided there is sufficient competition. 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.

Figure B5: Dispatch order



19. Typically capacity mechanisms pay all resource[25] the same, as they would all otherwise receive the scarcity rents the capacity payment replaces. However, in some countries capacity payments are paid to only some resource (e.g. the peaking plant that's only used for a small number of hours each year). In such markets, action is needed to prevent market distortion of the peak price signal (discussed further in section 6.6).

20. We have considered a number of approaches to improving security of supply relative to a "do nothing" counterfactual. A summary of each option is given below (Annex 2 provides further details on the options).

Option 1 - Do nothing (counterfactual)

21. This option retains the energy only market arrangements in its current form and relies on existing market price signals to drive investment and ensure security of supply.

Option 2 - Improve operation of current market (Improving the energy-only market: No capacity mechanism)

22. Under this option changes are made to improve the current system and retain the GB market as an energy only market. Price signals in the market are sharpened by undertaking reforms to the balancing arrangements, supporting liquidity enhancements, and improving diversity and the demand side. Key aspects are given below, and further details are in Annex 2. In addition, the Government will need to ensure that the reforms designed to support investment in low-carbon generation do not significantly distort the market. It should be noted that this option improves the general functioning of the market and so could be argued to be implemented regardless of decisions on a capacity mechanism[26].

23. Reforms to balancing arrangements: three reforms to the balancing arrangements have been suggested to give potential investors clearer price signals to provide the incentive to invest. Further details are given in Annex 2.

[25] Resource refers to demand-side response (DSR), energy efficiency, storage and interconnection in addition to generation.
[26] However as per paragraph 79, these changes in themselves are unlikely to eliminate all future risks to security of supply.

- Calculation of cash-out payments: For a number of reasons, the cash-out price may not fully reflect the costs of ensuring supply and demand are in balance and at times will be too low. If prices in short-term markets do not fully reflect scarcity of generating capacity, forward prices will also be muted[27]. These forward prices are commonly used by developers as the basis of investment appraisals. Ofgem has proposed a number of reforms to the cash-out price so that it is a truer reflection of the costs of that imbalance (i.e. to create more cost-reflective prices), which should therefore give stronger signals for investments in new capacity.

- Improvements to procuring of balancing services: A further way to improve cost-reflectivity of cash-out and to also provide greater transparency is to introduce a reserve market. A reserve market is a short-term market (for example, day-ahead) run by the system operator to procure reserve resources. This would enable the value of reserve to be factored into the cash-out prices in a way that more accurately reflect conditions on the day, and therefore cash-out prices will be better targeted at the participants causing any shortfall [28].

- Actions to manage intermittent renewables: In its Project Discovery, Ofgem proposed a form of centralised renewables aggregation that could allow intermittent renewables to face lower risks of imbalance.

24. Actions to improve liquidity: liquidity is an important feature of a well functioning market. Liquid markets offer a range of important benefits. For example it allows parties to better manage long-term risk, increases confidence in traded prices and facilitates new entry. Ofgem has set out four possible measures to improve liquidity in the market, these are outlined in Annex 2.

25. Actions to improve diversity and the demand side: the GB market is dependent on fossil fuel generation to provide the flexibility to respond to changes in demand or supply. Technologies such as demand side response, storage, interconnection and energy efficiency offer the opportunity to have a greater diversity of technologies, so improving security of supply, as well as reducing emissions. A more dynamic demand side response also increases competition and the effective functioning of the market, further details are given in Annex 2.

Option 3 – *A market-wide capacity mechanism (CM)*: A capacity mechanism for all generators

26. A capacity mechanism would require that the total level of capacity is determined centrally by Government (this would transfer the risk of their being insufficient supply from the market to Government). There are a number of ways to implement a market-wide CM, as summarised below:

    3a) **Capacity payment:** Reimburses all generators through a simple payment. The payment is defined to reimburse the full capex of the newest peaking plant over the life of that plant. It could be made up of an *ex ante* payment to provide certainty and an *ex post* payment, to reduce gaming, as used in the All Island Single Electricity Market of Ireland and Northern Ireland (SEM).

[27] Alessandro Rubino (2009), Investment in Power generation. Deliver reliability in a competitive market (a paper produced for Ofgem Project Discovery)
[28] Ofgem Project Discovery consultation (Feb 2010)

3b) **Capacity obligation:** Decentralised price set through an obligation on suppliers to contract with generators for a certain level of capacity or pay a buy-out price.

3c) **Capacity auction:** The capacity volume is set centrally a number of years (e.g. three years) in advance. Price is determined by auction and paid to all resource (existing and new) clearing the auction, as used in the American Pennsylvania, New Jersey and Maryland (PJM) and New England (ISO NE) electricity markets.

3d) **Reliability option:** Also a forward auction, but a financial market instrument (call option) rather than a physical instrument; generators must be available to the System Operator for dispatch above a defined strike price. This is untested, though it is a model that has been proposed by some academics.

27. In the current energy-only electricity market, when all the generators are running (in a scarcity period) the last plant will have market power and can charge more than its short run marginal cost (up to the value placed on avoiding lost load) and will entirely cover its capital costs through ‘scarcity rents’. All available generators receive both infra-marginal rents and scarcity rents, which are important for all generators to fully cover their capital costs. With a market-wide capacity mechanism, the capacity payment is intended to replace the ‘scarcity rent’. In an ‘energy and capacity’ market, competition in the generation market should drive out the scarcity rents, however this would need to be monitored to ensure generators do not receive double payments.

28. The capacity mechanism would require generators to declare their availability at gate closure. There is a risk that generators could declare themselves available even when they are actually unavailable to generate. A central body would need to monitor compliance to the capacity mechanism, for example run spot tests combined with large fines if they are unable to respond when called.

29. A market-wide capacity mechanism would be available to all resource, to include generators, demand side response, energy efficiency, storage and generators that are available over interconnections. Intermittent generators (such as wind) could be paid a de-rated capacity payment to reflect their availability, for example they could be paid a capacity credit *ex post* based on the periods when they were generating. This is feature of capacity mechanisms in both the Pennsylvania, New Jersey and Maryland market (PJM) in the US and the All Island Single Electricity Market of Ireland and Northern Ireland (SEM).

Option 4 – *A targeted capacity mechanism*: A capacity mechanism for some generators

30. Under this option, capacity payments are only made to those generators that provide the shortfall capacity needed to maintain capacity at the centrally determined level. This is most likely to be a centrally run system with price discovery through competition (an auction). The desired level of capacity would need to be determined. Then the amount that the central body would estimate how much resource was needed to maintain the capacity at the required level and then tender for this resource. Tenders could be technology neutral or run for different types of resource (e.g. with different degrees of flexibility including DSR) and payments and/or lengths of contracts differentiated accordingly

31. If the capacity procured could freely participate in the market this could lead to significant market distortion, as generators not receiving the capacity payments may not receive an adequate return on their investment because scarcity rents are removed from the market but not replaced by a capacity payment. Further, there is a potential 'slippery slope' issue in which the new contracts with the central body could be more attractive than remaining in the market and so this body ends up procuring all generation (except low-carbon if this is supported separately).

32. The Government anticipates any shortfall in capacity to be relatively small amount, and this is supported by the Redpoint modelling, which anticipates that around 5GW of resource is needed to keep a de-rated margin of around 10%. This means that, in any case, it should be possible to keep market distortion to a relatively small level.

33. In addition, the option would be implemented with the aim of minimising this distortion. The Government will explore the best approach to a targeted capacity mechanism as part of the consultation. The two main two main ways that resource receiving capacity payments could be dispatched are:
    - **Last resort dispatch (strategic reserve):** the resource is only used after all other resource has been exhausted (similar to the Peak Load Reserve in the Swedish market).
    - **Economic dispatch (extending STOR - Short Term Operating Reserve):** the resource is used when required to by the System Operator. It is dispatched when it is cost effective to do so, which may be before all other options are exhausted

34. This option also relies on effective functioning of the electricity market to incentivise existing capacity (nuclear, gas, coal) to remain open and new flexible capacity (i.e. CCGT) to be forthcoming. Therefore this would need to be coupled with moderate reforms as outlined in option 2.

35. Last resort dispatch would minimise market distortion. Economic dispatch could reduce the costs of the mechanism, but risks greater market distortion. This would need to be mitigated by including these actions in the cash-out price in a cost-reflective way. The choice between these approaches is a complex trade-off. For simplicity, Redpoint have modelled the first approach and undertaken some illustrative analysis on the distributional effects on the second (see section 6.3) with the assumption that no market distortions arise.

4. Approach taken for modelling

4.1 Introduction

36. Details of the Redpoint model and the modelling approaches to the EMR options are given in the Redpoint report accompanying the EMR consultation. For the purposes of the CM modelling, Redpoint have simulated the effects of a market-wide capacity mechanism using a fixed payment approach to achieve a given margin and the targeted mechanism on the basis of the System Operator (SO) tendering for capacity to meet a desired capacity margin. Differences between the different capacity mechanisms has been considered qualitatively. The assumed implementation date for CM measures is 2018 (however investors are assumed to have foresight of policy from 2016).

37. The market-wide mechanism was modelled on the following basis;

- An administered capacity mechanism in which a capacity pot (total amount remuneration available for capacity) is set by the value of capacity (based on the costs of a new entrant peaking plant) and the volume required (based on a defined security standard). The level of payment is fixed and does not change with the generation mix.
- The role of new DSR is not captured in the modelling, but 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. This has been shown by experience in the USA, for example (see paragraph 64).

38. The targeted mechanism was modelled on the following basis;

- 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 (see paragraph 64)
- It is assumed tendered capacity does not affect the wholesale market or weaken investment signals for non-tendered capacity.

4.1.1 Caveats to the modelling

39. The baseline does not achieve the indicative level of decarbonisation for the purposes of the modelling and therefore the capacity mechanisms need to be tested against a scenario where these objectives are met. A fixed payment decarbonisation option was chosen to demonstrate the impact of a capacity mechanism because there are less complex interactions with a fixed payment which decouples the low-carbon generation from the market. For further details on the interactions between the capacity mechanism options and decarbonisation options.

40. The Redpoint quantitative analysis does not include all the costs and benefits of the proposals[29], primarily since these are dependent on mechanism design and some cannot be quantified. However the cost benefit section attempts to synthesise both the Redpoint analysis together with the available qualitative evidence.

[29] Costs such as admin, gaming (as model assumes a competitive market with SRMC bidding etc – see Annex 1 for discussion of GB market) are not covered by the modelling but have been discussed qualitatively in section 6.8 and covered in the decarbonisation IA.

41. On the whole the Redpoint analysis will tend to understate the risks to security of supply. This is because of the following reasons

- Has made a conservative assumptions about society's valuation of supply disruption or value of lost load (VOLL), it is at the lower end of ranges that have been cited (see paragraph 5). Hence benefit quantifications are towards the lower end.
- The model does not capture the market imperfections we highlight in Section 2, these 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 B1) has fair degree of dispersion and is both asymmetrical and complex.

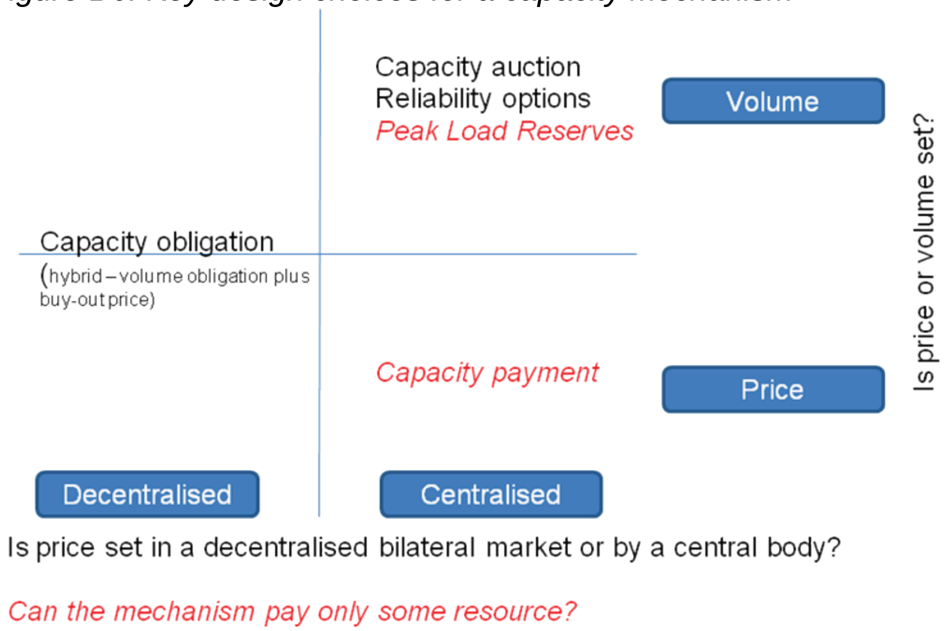
5.0 Relative comparisons between the capacity mechanism options

42. While there are a number of types of capacity mechanism, the Government has identified three main dimensions:

- The price can be determined centrally or through bilateral contracts;
- the price or the volume can be set; and
- the mechanism can pay all or some resource.

Each of the capacity mechanisms described in Options 3 and 4 have different characteristics, how each capacity mechanism fits under the design choices is demonstrated in Figure B6 and further details of each mechanism is provided in Annex 2. In addition there are a number of further design questions which are assessed here.

Figure B6: Key design choices for a capacity mechanism



5.1 Capacity mechanism for all or some?

43. Typically capacity mechanisms pay all generators the same, as all generators would otherwise receive the scarcity rents that the capacity payment replaces. However, capacity payments could be paid to only some generators (e.g. the peaking plant that is only used for a small number of hours each year) if any resulting market distortion can be effectively mitigated. The key differences are as follows:

- If run by a central body, a market-wide capacity mechanism only requires setting the total volume of capacity needed, whereas under a targeted capacity mechanism a central body has to estimate how much resource the market will provide and how much extra is needed and this determination occurs in a much more transparent manner.
- A market-wide capacity mechanism is less likely to distort the market because the payment is made to everyone. It is more likely that a targeted capacity mechanism will distort the market, so mitigation will need to be built into the design of the mechanism.
- A targeted capacity mechanism allows different prices and/or contract lengths to be given to different types of resource, whereas in a market-wide capacity mechanism all resource receives the same price (although there is some flexibility to differentiate contract length).

5.2 Central or decentralised price setting?

44. The price of capacity can either be set centrally or determined by the market. For all of the capacity mechanisms described, suppliers pay for their capacity requirements. In most mechanisms capacity is procured by a central body, which is reimbursed by suppliers. The exception is the capacity obligation, where suppliers procure the capacity they need to meet the obligation directly from generators under bilateral contracts).

45. The Government has considered lessons from the Renewables Obligation; the parallels that exist in our current bilateral electricity market and modelling of a capacity obligation previously commissioned by DECC[30].

46. As the decentralised price setting mechanism of a capacity obligation is closest to the current market arrangements, it would have the following advantages over options run by a central body:
    - May have a lower risk of unexpected outcomes, in particular as it can be introduced in a more incremental fashion than most other options.
    - Allows more decision making (e.g. levels and types of capacity) by market participants who may be better able than Government to make informed decisions.
    - Does not require institutional change.

47. However, a centralised approach (through a payment or an auction) has a number of significant advantages over a capacity obligation:
    - A centrally-set price and contracts will be more transparent than in a capacity obligation giving a lower risk of double payments and gaming.
    - A centralised approach is likely to reduce barriers to entry associated with the current market arrangements. A decentralised mechanism promotes a greater degree of bilateral contracting between generators and suppliers to better manage risk profiles, this can lead ultimately to more vertically integrated structures.
    - The interrelation between capacity reserves and reserves needed for the balancing mechanism[31] will be significant as intermittency increases. Having both set centrally, rather than one set bilaterally and one centrally, will make this easier to manage.

48. In conclusion, the Government assesses that the advantages of a centralised system outweigh those of a capacity obligation.

[30] Dynamics of GB generation investment, Redpoint (2007)
[31] With current arrangements, the system operator only has responsibility to balance system 1 hour before real time (period of gate closure) it has no responsibility to ensure adequate capacity of the right type is available prior to that period and expects the market to bring this forward. A centralised approach allows better co-ordination to ensure both the types and amounts of capacity are complementary to the overall balancing requirements of the system.

5.3 Set price or volume?

49. A central body could ensure sufficient capacity is procured by either setting a price of capacity to ensure it incentivises sufficient volume to be brought forward by the market, or by setting the volume of capacity required and allow the market to discover the price.

50. A capacity payment would allow a central body to set the price of capacity directly. The advantages are that it is relatively simple concept (although in practice setting the "right" level is quite complex) and is compatible with existing institutional arrangements. Disadvantages are that the level of payment is not flexible with changes in the generation mix and there are significant risks of either over-paying or of not obtaining the desired level of capacity. The Redpoint modelling demonstrates that the level of payment is extremely difficult to set correctly. When the level of payment was set to get a margin of 10%, it resulted in margins well above this. Scaling back the payment by 70% still gave similar margins in a more efficient way (i.e. the costs to consumers were lower), but the payment level was insufficient to incentivise new peaking plant. In scenarios in which new CCGT was needed[32], the payment level was insufficient and margins collapsed almost to zero.

51. The modelling undertaken by Redpoint has been on the basis of price setting approach for a market wide capacity mechanism and the volume of capacity was an output of the model. However for the targeted capacity mechanism the volume was fixed, in practice the corresponding price would have been realised via a capacity auction. Whilst it was not possible to explicitly model the price, it was separately derived outside of the main modelling exercise.

52. The Government expects, based on experience in the PJM and Swedish PLR markets (both described in Annex 2) and competitive tendering for STOR[33] in GB market, that a competitive auctioning process would enable price discovery and overcome the problems encountered with the price-setting approach. This is a significant benefit that seems very likely to outweigh the marginal increase in administrative complexity over that needed for a capacity payment.

53. In conclusion, approaches in which volume is set (capacity auctions, reliability options, peak tenders) are preferable to capacity payments.

5.4 Transfers of risk management

54. An energy-only market ensures that market participants bear the risks of insufficient capacity adequacy, through penalties in the balancing mechanism, and possibly through some reputational damage or loss of business etc. A market wide capacity mechanism would transfer all capacity risk management to the government, where the risks of over or under estimating capacity need is ultimately borne by consumers. Whilst this is also true of a targeted mechanism, the risks transfer is lower since the government is only taking on the risk for the residual amount of capacity (that which the market is not sufficiently bringing forward) hence consumers bear a lower level of risk.

[32] In Redpoint simulations where derated margins are low, scaling capacity payments could result in increased risks that new CCGT investment would not be forthcoming.
[33] STOR is defined as short term operating reserve, which the National Grid procures as part of its balancing services

6. Costs and benefits

6.1 Introduction

55. This section considers the costs and benefits (CBA) of each option relative to the counterfactual. Since the main CBA differences between choice of CM option is between a market-wide and targeted scheme (choice of market-wide CM design are primarily ones of implementation - as discussed in previous sections) this section examines these options relative to the counterfactual whilst highlighting any explicit differences between the two options where applicable. The costs and benefits have been quantified wherever possible and broken down into the following elements:
    - Economic efficiency
    - Distributional impacts
    - Barriers to entry and competition
    - Security of supply
    - Market distortions
    - Transitional issues
    - Wider macroeconomic effects
    - Impacts on business

6.2 Economic efficiency impacts

6.2.1 Net Welfare (costs of capital, resource costs and decarbonisation)

56. **Improve energy-only**: Redpoint modelling has not been undertaken on this option. However the qualitative analysis suggests that if liquidity develops to the extent that price risks could be better managed then this option could have some benefits in terms of reducing risks to investors and so reducing the costs of capital. Similarly for renewables if imbalance risks are better managed (through aggregation) then again this could have effects on the costs of capital. However prices are just one area of uncertainty and so overall it is difficult to say if there will be a discernable impact on the overall cost of capital.

57. An improved energy-only framework is likely to deliver some certainty to CCGT investment, and therefore reducing security of supply risks, but the effect is likely to be minimal compared to the status quo. For example, an idea of the size of the effect on investment can be gained from Redpoint analysis for the Ofgem Project Discovery which demonstrated that (all other things being equal) a de-rated capacity margin in the region of 10% might be expected if prices are able to rise to £5,000/MWh, but a de-rated capacity margin of 1-2% lower could be theoretically expected if prices could only rise to £500/MWh. Therefore the Government concludes that these changes in themselves although could make a valuable contribution to security of supply may not be able to fully address the security of supply risks envisaged. Similarly we envisage there to be marginal difference to the baseline in terms of resource and carbon costs.

58. **Capacity mechanisms** (CM): Redpoint have modelled the effects of a market-wide and targeted capacity mechanism. Electricity markets are prone to cyclicality, a CM reduces this due to smoothing of revenue flows since generators are less reliant on tight markets to remunerate their investments. This reduced cyclicality reduces investor revenue uncertainty, which leads to reductions in the cost of capital which can lead to lower

resource costs and hence welfare benefits[34]. To illustrate this effect the EMR Redpoint simulations given in Table B1 shows the reductions in hurdle rates[35] as a consequence of a capacity mechanism.

Table B1:Impact of capacity mechanism on hurdle rates

Technology	Impact on hurdle rates
CCGT	-0.3% to -0.4%
CCGT+CCS	-0.5% to -0.8%
Coal+CCS	-0.5% to -0.8%
Nuclear	-0.5% to -0.8%
Onshore wind	-0.1% to -0.2%
Offshore wind	-0.2% to -0.3%
Biomass	0.2% to -0.3%
OCGT	-1.0% to -1.4%

59. In terms of the overall effect on net welfare, Table B2 below summarises these for both options. The main differences are that a market wide capacity mechanism (option 3) results in older and less efficient plant staying on the system and providing capacity. The effect of this is that no new plant is built and generation costs are greater, also the carbon savings are lower. Whilst the benefits of less unserved energy are greater with option 3 this is a consequence of having a larger supply margin over the targeted capacity mechanism (option 4). The larger margin is a consequence of the difficulties in setting an appropriate capacity price which can result in over capacity (see section 5.3). In this instance the price signal results in more existing plant (which otherwise would have closed), opting to stay on the system rather than close due to the capacity mechansim, hence whilst the payment is set to achieve a particular margin, in the simulation more capacity is delivered than was initially desired. In contrast with option 4 there is a targeted and centrally prescribed amount of capacity (quantity) that is procured by the central body to maintain the given level of security of supply. The overall change in net welfare is marginally better under option 4[36].

Table B2: Change in net welfare relative to baseline, NPV 2010-2030, £m (2009 real)

Option	**3**	**4**
Value of carbon saved	18	82
Change in running costs for generation	-1287	-709
Increase in capital costs of new plant	0	-470
Less unserved energy (security of supply benefit)	434	404
Demand side response	61	0
Change in Net Welfare (NPV)	**-774**	**-694**

60. Whilst the net welfare is negative it is worth bearing in mind an important sensitivity to the estimate of unserved energy. This is based on a value of lost load (VOLL - the cost society places on supply disruption) at around £10,000MWh. However estimates of VOLL are very 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 on how to derive an appropriate value to lost load (an aggregate measure

[34] The modelling assumes that a reduction in the costs of finance are a resource saving, i.e. an overall benefit to society.
[35] Hurdle rates are the rate of return that a project needs to achieve before they are given the go ahead and are directly related to the risks associated with a project and the associated costs of finance.
[36] The modelling assumes a mix of new and existing plant is contracted by the central body, as is likely to occur under a tendered auction approach.

of the costs of interruption), some estimates have put it around £30,000MWh[37]. 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 then there would be an overall (although marginal) welfare gain from both these options. Table B3 illustrates the effect of using a VOLL of £30,000MWh;

Table B3: Change in net welfare relative to baseline, NPV 2010-2030, £m (2009 real)

Option	**3**	**4**
Value of carbon saved	18	82
Change in running costs for generation	-1287	-709
Increase in capital costs of new plant	0	-470
Less unserved energy (security of supply benefit @ VOLL = £30000/MWh	*1302*	*1212*
Demand side response	*61*	*0*
Change in Net Welfare (NPV)	***95***	***114***

61. Similarly, the Redpoint modelling does not capture the benefits in terms of resource cost savings from new demand side resources (DSR) participating in the market with a market-wide and targeted CM. Experience from the US[38] 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.

6.2.2 Enabling demand side response, energy efficiency and storage

62. **Improve energy-only:** The set of measures to improve the involvement of the demand side in system balancing[39] will help enable greater demand side participation. However, whilst there is likely to be demand side response that would be able to help reduce the amount of new-build generation required this may not be of sufficient quality (i.e. reliability) to be used in the balancing mechanism. Moreover whilst the higher prices from the cash-out reform, together with specific actions to address entry barriers, may help demand side enter the market, this still would be uncertain (and levels may still be insufficient). There would also not be the option to directly incentivise energy efficiency. Therefore, this would not enable as much demand side as much as a capacity mechanism.

63. **Capacity mechanisms**: DSR could be incentivised in a similar manner under both options 3 and 4. There is evidence of this from the international experience with capacity mechanisms some examples are given below:

64. Market-wide CM: US Forward capacity markets have shown considerable success in increasing the amount of demand side response (DSR). Based on evidence from

[37] With smart metering and dynamic demand VOLL estimates may become easier to ascertain.
[38] 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.
[39] This consists of the balancing mechanism used to balance the system after gate closure, initially at an aggregate national level and subsequently to relieve network constraints, and balancing services which are various reserve, response and other system services contracted for in advance of gate closure and called to operate as required in real time.

Regulatory Assistance Project[40] on US capacity mechanisms, demand side resources in New England have provided around 10GW of capacity in the forward capacity auctions and reduced the costs of capacity provision (see Annex 2).

65. Targeted CM: DSR accounts for approx two thirds of the reserve bid into the Norwegian reserve market (maximum weekly purchases of DSR were nearly 1500MW in 2006 with the offered volume even higher). Since Sweden started purchasing peak power reserves, the amount of DSR offered in the tender procedure has increased annually and for 2005/2006 comprised of slightly more than 870 MW of demand resources, which is about 23% of the total amount of reserves offered. This compares with DSR making up approximately 10% of GB STOR[41] requirement.

6.2.3 Efficient dispatch

66. **Improve energy-only**: A sharper price signal could provide a greater reliability incentive so aggregate balancing costs might be lower (hence more efficient/low cost dispatch) as less expensive units are called upon in the event of an unplanned outage. Similarly any aggregation of renewable output could also ensure more efficient dispatch and reduce aggregate balancing costs.

67. **Capacity mechanisms:** A CM will (by design) reduce the electricity price peaks that incentivise efficient dispatch. For both options the dispatch signals remain in place, in that 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. The incentive however for the marginal plant (and that contracted on the basis of a fixed strike price to provide capacity with targeted CM) to be available at times of particular tightness is weaker compared to an the energy-only market. The key issue here is indifference to the timing of maintenance periods, rather than the explicit lack of an incentive to be available. Various capacity mechanism design incentives could be put in place to ensure the correct dispatch signals are available to all plant, such as penalties and increased regulation/monitoring.

6.2.4 Incentives for innovation

68. **Improve energy-only:** A sharper price signal could lead to innovation in risk management, procurement and contracting, forecasting and aggregating. The Government also expects suppliers to better compete on products and service. However any increased price risks (where hedging products are not available) may reduce innovation for new technologies.

69. **Capacity mechanisms:** Where a capacity market encourages new entry, it may result in competitive forces driving innovation in some technologies, in order to ensure cost advantages relative to other players. This may be pertinent in the case with demand side providers. Where the capacity mechanism is a blanket incentive, and there are no further innovation incentives on the System Operator in its procurement, then overall this is likely to have a relatively small effect. Hence innovation in new flexible technologies is unlikely to be significantly improved compared to the current arrangements (whilst there will be

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[40] Gottstein, Op cit, 2010.
[41] STOR is defined as short term operating reserve, which the National Grid procures as part of its balancing services.

some increase in DSR as international experience shows), unless these are advocated as part of the capacity mechanism design (this would apply equally to a targeted or market-wide CM).

6.3 Distributional impacts

70. **Improve energy only:** This option has not been assessed in terms of its distributional impacts, however these are not expected to be materially different relative to the counterfactual/status quo.

71. **Capacity mechanisms:** Whilst the net welfare effects show there is marginal difference in the costs between the options, the Redpoint analysis suggests there is a difference between the distribution of these costs between consumers and producers. Both options result in a transfer from consumers to producers, however a market-wide CM would result in a larger transfer and producer surplus. This is primarily a consequence of older plants which have recovered their investment costs deriving rents from capacity payments and also receiving these large capacity payments even when de-rated margins are high[42]. However, a capacity mechanism for some is much more targeted by only making payments to resource making up any shortfall, therefore less is acquired at a lower cost. Since the targeted CM incentivises both old and new plant through a competitive tender, there is less rent capture so producer surplus is much lower under this option.

Table B4: Distributional analysis of options, NPV 2010-2030, £m (2009 real)

Option	**3**	**4**
Change in wholesale price	27,599	-279
Change in low-carbon support*	-7,915	39
Capacity payments	-29,196	-1,133
Unserved energy	434	404
Demand side response**	61	0
Change in consumer surplus[43]	**-9,016**	**-969**
Change in wholesale price	-27,599	279
Change in low-carbon support*	7,913	-37
Change in producer costs	-1,269	-1,098
Capacity payments	29,196	1,133
Change in producer surplus	**8,240**	**277**

*As per para 40, the decarbonisation option is fixed payments. Where wholesale prices fall (as with market-wide CM) more would be required from such payments. The overall support level for low-carbon (jncl the electricity price) remains the same however, so the driver of rents is the capacity payments being paid to generators. The relative comparison between the distributional effects of the two options are the most significant inferences to be drawn from this table.

**In (Option 3) market-wide, the use of DSR is reduced. This is because there is more capacity available and so peak prices rarely reach the levels at which demand would turn down rather than pay that price – the benefit of this reduced use of DSR is shown in the CBA. In the Targeted Capacity Tender, the tender capacity is considered the capacity of last resort (excluded from the wholesale market), and therefore prices reach higher levels and DSR is triggered and there is no corresponding benefit as a consequence.

72. Redpoint analysis also demonstrates that where market distortions and rent capture can be further limited through design there would be greater benefits to consumers from enhanced consumer surplus. These are discussed further below.

73. Table B5 (as compared to Option 3 in Table B4) shows simulations on the effects of a market wide capacity payment that is just sufficient to incentivise existing plant to stay on

[42] Redpoint, however, note that an capacity auction approach could reduce this effect.
[43] For simplicity change in environmental tax i.e. CCL are not shown as these are relatively small.

the system. This could be used as a proxy for an auction, which is expected to achieve a similar outcome (with the caveat that the results could be towards the optimistic end). The analysis suggests a much lower effect on consumer surplus.

Table B5: Distributional analysis of option 3 with low payments, NPV 2010-2030, £m (2009 real)

Option	**3 (with low payments)**
Change in wholesale price	27,599
Change in low-carbon support*	-7,915
Capacity payments	-20,437
Unserved energy	434
Demand side response	61
Change in consumer surplus[44]	**-257**
Change in wholesale price	-27,599
Change in low-carbon support*	7,913
Change in producer costs	-1,296
Capacity payments	20,437
Change in producer surplus	**-518**

74. The Redpoint analysis also suggests that where a targeted CM is designed such that plant is despatched on the basis of least cost (its lower cost means its despatched whenever economic to do so), as opposed to being used only as generation of last resort could result in further benefits to consumers. 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[45]. If, for example, the tendered 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 targeted CM. However, Redpoint state that it is difficult to draw strong conclusions as to whether a targeted CM could result in such savings to customers without a better understanding on how prices behave under times of system stress, and how the tendered capacity would be deployed and priced into the market.

Table B6: Consumer bill impacts of capacity mechanisms

Option	**Average bill with FP**	**Change in average bill with market-wide CM**	**Change in average bill with targeted CM**
Domestic (£)			
2010	£493	0% (£0)	0% (£0)
2011-2015	£476	0% (£0)	0% (£0)
2016-2020	£495	4% (£19)	0% (£1)
2021-2025	£584	0% (-£5)	0% (£2)
2026-2030	£657	2% (£14)	0% (£2)
Average 2010-2030	£550	1.2% (£7)	0.2% (£1)
Non-domestic (£000)			
2010	£918	0% (£0)	0% (£0)
2011-2015	£947	0% (£0)	0% (£0)
2016-2020	£1,146	5% (£56)	0% (£2)
2021-2025	£1,475	0% (-£12)	0% (£6)
2026-2030	£1,497	2% (£37)	0% (£5)
Average 2010-2030	£1,250	1.5% (£19)	0.2% (£3)

[44] For simplicity changes in environmental tax i.e. CCL are not shown as these are relatively small.
[45] As explained in paragraph 9 there may be reasons why under the current arrangements this may not happen.

6.3.1 Impact on consumer bills

75. Table A6 shows the estimated impact on average annual domestic and non-domestic electricity users' bill from the introduction of a market-wide CM and targeted CM to the fixed payment option, relative to a bill including fixed payments with no capacity payments[46].

76. There is a negligible estimated impact on average bills from the introduction of targeted capacity tenders in a scenario with fixed payments. However, the modelling suggests that the costs to consumers are greater with a market-wide CM than with a targeted CM.

6.4 Barriers to entry and competition

77. **Improve energy-only**: Liquidity enhancements can reduce barriers to the market, since liquidity both facilitates trading as well as enhances the reliability of market price signals. This is becomes particularly important with sharper cash-out prices as participants become more reliant on liquid markets to be able to hedge imbalance risks against. Moreover with reduced barriers to entry for DSR and renewables (from lower imbalance risk from aggregation) this should encourage more competition, since more new entrants can enter and participate in the market.

78. **Capacity mechanisms:** The degree to which the capacity market will function effectively is important; this includes the liquidity, degree of competition and level of barriers to entry. There may also be some impacts on the energy only aspect of the market.

79. Both options can enable greater involvement of the demand side (thus reducing barriers for new entrants) although a market-wide CM has a proven record in other countries in delivering large amounts of DSR. Moreover, incentivising more DSR may reduce market power in the electricity market and enhance competition. For example, US markets such as PJM and New England have had significant amounts of DSR making demand more elastic, which has reduced the scope for market power amongst generators. However, market power opportunities will exist in any market design and this will still require regulatory oversight.

80. The capacity mechanism will also have some indirect impacts on the energy-only market. This is envisaged to have an effect on liquidity, however the overall impact is uncertain. A capacity market would change the nature of the market (as capacity is now remunerated explicitly in a separate capacity market) but the overall effect will depend on the interplay of preferences between suppliers and generators and its design. Overall the effects on liquidity are assessed to be neutral to low. A few points are given below to illustrate the various effects.

    a) A capacity mechanism will require increased monitoring in wholesale/prompt markets, to ensure generators do not receive double payments. This could encourage more

[46] For details on methodology on the estimation of bills, please see the decarbonisation IA

bilateral contracting[47] as these are less transparent – hence would a negative effect on liquidity.

b) However, independent suppliers (and generators that are net short) could prefer to buy from prompt markets since they know they are buying at SRMC, and hence limit their use of bilateral contracts - hence could have a positive effect.

c) The electricity market already consists of a number of markets, participants are likely to be involved in both the capacity and energy market this would be an additional market and the same participants plus new entrants (including demand side providers) will be encouraged and will participate to provide capacity. The short term energy market will still be traded but on pure energy only terms. This should overall have a neutral to positive effect on liquidity (depending on levels of new entry).

d) A market-wide CM implemented through a capacity obligation is more likely to re-enforce bilateral contracting and vertical integration in the sector, this approach would tend to reduce liquidity.

81. It is worth noting that both a market-wide and targeted CM would work alongside moderate changes to the energy-only market; for example, counteracting liquidity enhancing measures that will further act to mitigate any adverse effects.

6.5 Security of supply

82. There are a number of different aspects of security of supply:

- Real-time balancing. The System Operator needs to be able to call upon resources to balance unexpected changes in supply or demand (*security*);
- Short-term dispatch: More resource needs to be incentivised to be available at times of higher demand than at times of lower demand (*firmness*); and
- Long-term capacity: Sufficient capacity needs to be built so that enough resource exists to meet needs (*adequacy*).

83. In addition there are other important aspects of security of supply, in particular diversity of supply that needs to be maintained.

84. **Improve energy-only**: Within the current market framework real time balancing is the responsibility of the System Operator, while the electricity price incentivises both short-term dispatch (prices are higher at times of system tightness) and long-term capacity (average return exceeds total costs). Diversity of supply is also maintained through market signals. The changes advocated by this option will act to sharpen price signals and enhancing liquidity therefore addressing some of the uncertainties around revenue for peaking generation. This should enhance investor confidence in the market framework. Analysis by Redpoint (as discussed in paragraph 57) suggests that this may not be sufficient in providing the security of supply margins required, particularly where generators perceive risks around not receiving the scarcity rents. Moreover, the risks to security of supply from investment cycles would still persist. On the whole, therefore, there

[47] So long as wholesale markets are liquid and transparent bilateral contracting that are arranged directly between participants would be referenced or linked to the wholesale market. Where the market lacks liquidity, bilateral contracting would tend to re-inforce illiquidity and further reduce transparency.

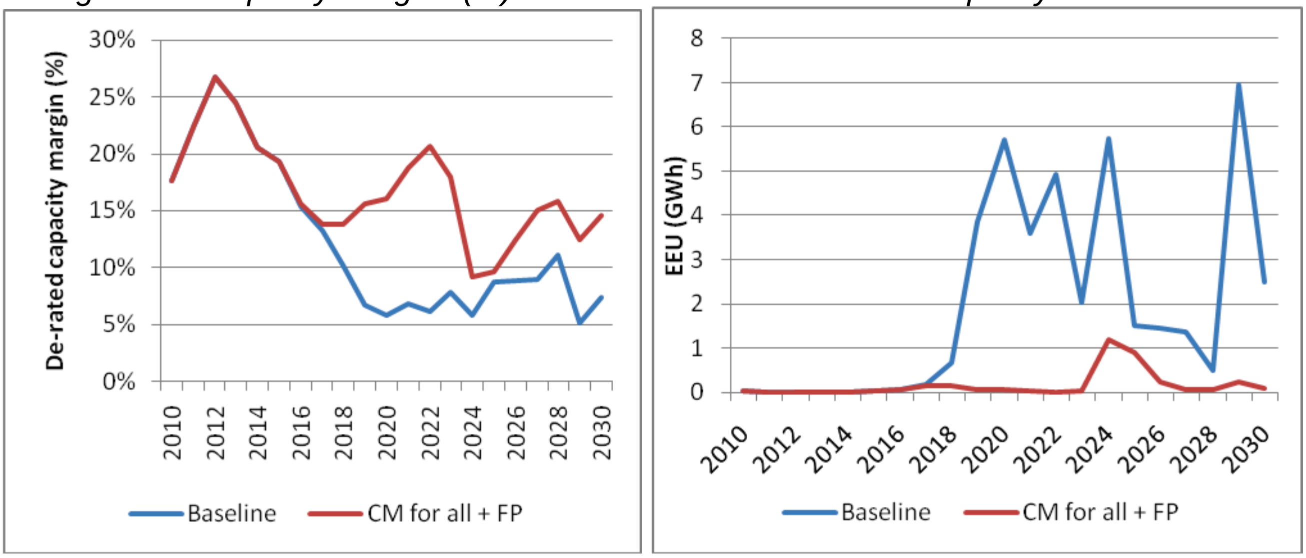
is likely to be a moderate improvement to security of supply relative to the baseline with this option.

85. **Capacity mechanisms:** A capacity mechanism seeks to remedy issues associated with long-term capacity. However, it must do this while not damaging the other aspects of security of supply, therefore the capacity mechanism intervention will need to:
- Give sufficient investor returns (i.e. replace so called ‘missing money[48]’);
- Give investors sufficient revenue certainty; and
- Not impact on the viability of existing plant by distorting the market.

86. Both CM options would be set to incentivise the resource needed for both demand and reserve and bring forward the necessary investment. Since the central body has a role in short term balancing and longer term capacity procurement there is a neutral effect on real-time balancing and short term dispatch efficiencies can also be maintained.

87. Redpoint analysis suggests that if generators are confident in the market investment framework this will provide them with the incentive to increase overall capacity, therefore improving supply security. On the basis of the modelling it can be seen that the benefit to long term security of supply (lower risks of unserved energy) is consistent in both options with present value (PV) estimates at £434m for option 3 and £404m for option 4 (see table B2). Furthermore the charts below show the simulated effects on capacity margins relative to the baseline, where both capacity mechansim options improve the security of supply position. A targeted tendering for capacity is expected to lead to a more stable de-rated peak capacity margin and reduced risk of EEU (assuming SO forecasts are sufficiently accurate).

Figure B7: Capacity margins (%) and EEU with a market-wide capacity mechanism



48 In an energy only market prices need to be able to rise to sufficiently high levels to incentivise investments, where they do not due to price capping or system actions damping prices, or there is a perception of Government taking such actions, this is termed as “missing money” in the academic literature.

Figure B8: Capacity margins (%) with a targeted capacity mechanism

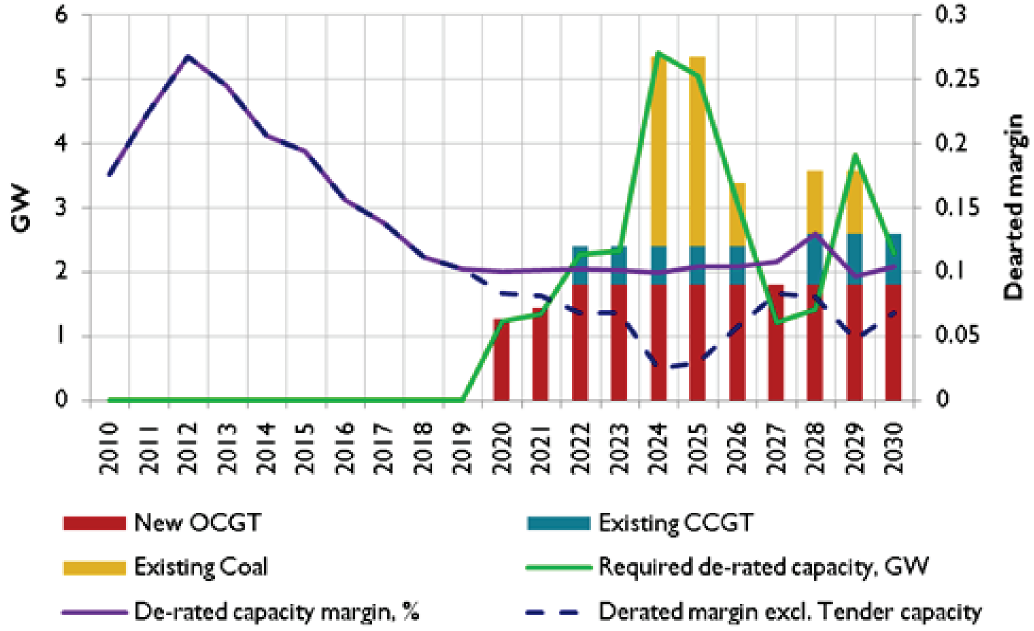
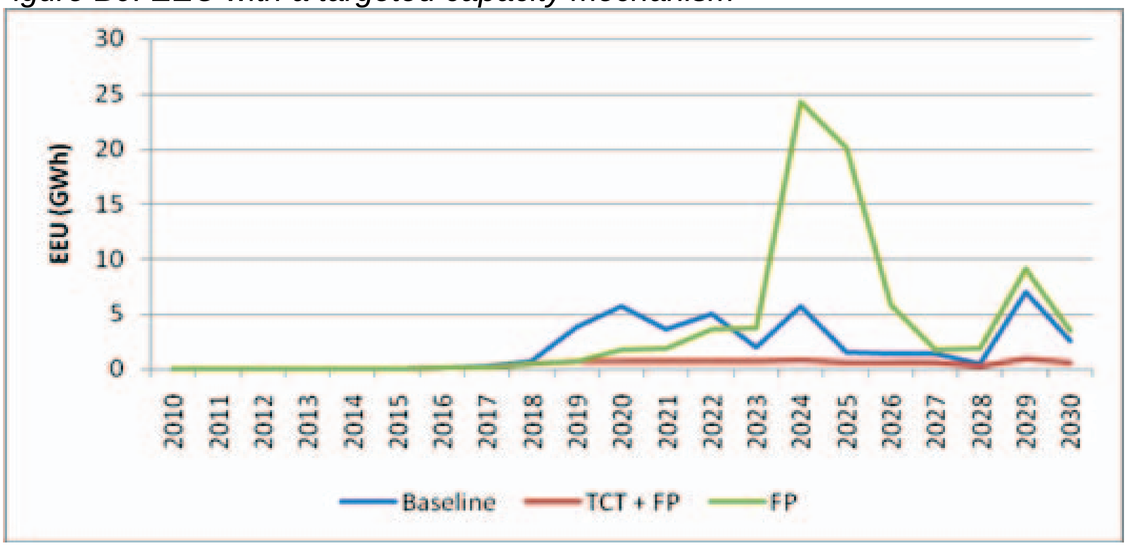


Figure B9: EEU with a targeted capacity mechanism



88. To the extent that a capacity intervention will bring forward greater amounts of demand side resources (DSR and energy efficiency and also potentially microgeneration) then it will have a beneficial effect on diversity of supply. Should there be a need for greater incentives for diversity then the instrument could further be used to incentivise different types of supply, for example different auctions or tenders for different types of capacity. However, these will all involve an increase in complexity in the mechanism.

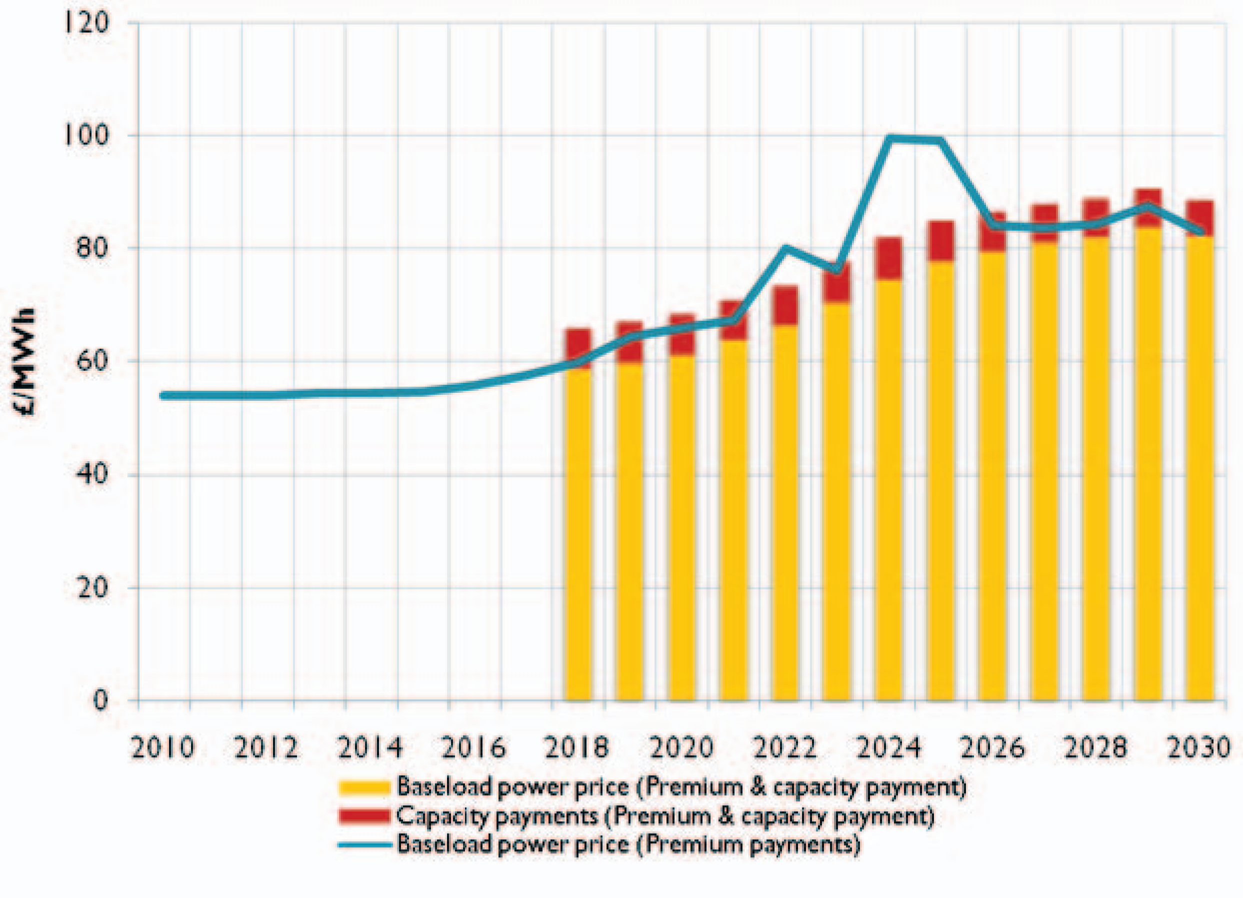
6.6 Market distortion

89. **Improve energy-only:** The collective measures would enhance market functioning and seek to reduce distortions where they currently exist, for example with unreliable price signals and barriers to entry.

90. **Capacity mechanisms:** A market-wide capacity mechanism will (by design) change the energy-only nature of the market by reducing scarcity pricing. This has the consequence of

reducing wholesale price volatility, since price uplifts required to remunerate investment is replaced by a steady stream of payments, see Figure B10 below.

Figure B10: Impact of a market-wide capacity payment on wholesale electricity prices



91. In a market-wide capacity mechanism existing and new plant are on an equal footing, hence there should be minimal market distortion. However with a targeted mechanism there is a risk of market distortion if the scarcity rents that ensure that all capacity (not just the balancing plant) achieve an adequate return on investment are taken out of the market, but not replaced by a capacity payment to all. Further distortion arises where new contracts with the central body are more attractive than remaining in the market and so this body eventually ends up procuring all generation (except low-carbon which will be supported separately). The Government expects the issues should be able to be mitigated through design. The Redpoint modelling implicitly assumes that the design is such that these distortions do not arise. However to the extent that designs are not adequate or result in unintended consequences then some risks could remain (see section 7 for discussion of costs of market distortions).

6.7 Transitional issues

Investment hiatus

92. Changes within the energy-only framework are unlikely to have much discernable impact on immediate investment choices. However with any CM option whilst it is beneficial for security of supply, there is a risk of a hiatus while it is implemented. GB currently has excess capacity, therefore investment hiatus should have a relatively low impact and could be dealt with through implementation, however this will be an important aspect of the mechanism design.

6.8 Wider macro-economic effects

93. **Improve energy-only**: This will work towards improving general market functioning and enhancing the investment environment.

94. **Capacity mechanisms:** The introduction of a capacity mechanism could reduce the cyclicality of the electricity market. An investment cycle results from herding behaviour of investors (responding to high prices when capacity margins are tight) and the inherently lumpy nature of generation (long lead times of generation plants). A capacity mechanism could reduce this cyclicality by smoothing revenue flows since generators are no longer reliant on tight markets to remunerate their investments.

6.9 Impacts on business

95. **Improve energy-only:** Improvements to the energy only market will lead to some costs to business, but these are expected to be lower than the costs incurred by introduction of a capacity mechanism. The reforms will be introduced by Ofgem, and costs will depend on which reforms Ofgem chooses to introduce.

96. Capacity mechanism: Benefits to business from the introduction of either capacity mechanism would be increased security of supply and thus reduced lost load. It has been estimated that the value of a reduction in unserved energy could be around £400million to £1.2bn (PV, 2009 real) for society as a whole for the period 2010-2030, but the exact share this benefit accruing to business is not known. A rough estimate of the benefit accruing to business using non-domestic consumers' share of electricity consumption (c.40% in 2009)[49], and assuming that benefits from reduced unserved energy are valued the same for all consumers, the benefits to business could be around £160million to £480million in the same period. The benefit estimated here would be understated if energy unserved (voltage reduction and possible supply interruptions) are in fact more detrimental to businesses than other consumers.

97. The primary ongoing cost to market participants under a market-wide capacity mechanism is the cost of trading capacity. In addition, suppliers and generators will need to estimate annual capacity needed/generated. It is likely that businesses already undertake this as part of their business planning, but may need to do it more formally. Costs will vary depending on the mechanism, for example a capacity auction would require generators to pass a pre-qualification. Most business will be unaffected by a partial capacity mechanism. Only those energy companies tendering for capacity payments could incur incremental administrative costs, and many of the required processes are already in place for the Short Term Operating Reserve Requirements in the current market.

98. The incremental impact on electricity bills for domestic and non-domestic consumers would be near zero from the introduction of a targeted capacity mechanism. The main costs to business would likely be the cost of trading capacity, and estimation by suppliers of generators of annual capacity needed/generated. However, the Government believes that business already undertake this as part of their business planning therefore incremental costs would be minimal. To put into context, the total cost for the agent administrating a market-wide capacity mechanism is estimated at £3-£10 million per year,

[49] Digest of UK Energy Statistics (2010), DECC

with the total administrative cost for a targeted capacity mechanism likely in the lower end of this range because it is less complex.

99. If one assumes that the total administration cost of a targeted capacity mechanism (c.£3m p.a.) is the upper bound for what the administrative cost could be to business, a very crude estimate of the upper limit of total cost to business over the period 2010 to 2030 is around £40m PV for this option. This implies a very crude estimate of net benefit to business of around £100-£400million NPV for the targeted capacity mechanism. Similarly, if one assumes that the upper end estimate for the total administrative cost of a market-wide capacity mechanism to be towards the higher end of the agent's total cost of administrating a market-wide capacity mechanism (c.£10m p.a.), a very crude estimate of the total cost to business over the same period is around £120million PV. This implies a net benefit to business of around £40-£350million NPV for the market-wide capacity mechanism[50].

7.0 Other costs (including administrative costs)

100. **Improve energy-only:** Since this is working within existing frameworks, we do not envisage any significant additional costs, particularly since the established procedures are already in place to accommodate incremental changes and monitor their effectiveness.

101. **Capacity mechanisms:** There are likely to be other costs associated with this measure such as administrative costs, risks from system gaming, risks of double payments and unintended consequences. These costs would be greatest under a market-wide CM and likely to be lower with a targeted CM. Some discussion of these costs is given below.

102. *Administrative costs:* A large number of administrative systems would need to be put in place to run and monitor any market-wide capacity mechanism - all suggested options are much more complex than the current energy-only market. Relative complexity and the costs associated with this will vary with design, for example PJM employs an agency to monitor the market; this monitoring organisation employs 30 people and costs $10 million (£6 million) per year (the PJM wholesale electricity market is approximately twice the size of the GB market). A targeted capacity mechanism would have much lower administrative costs because the central body will only have to administer a small part of the market and many of these processes are already in place for the STOR, therefore would just need expanding.

103. In terms of understanding the scale of the costs, these can be estimated by considering international examples and the costs of running the Renewable Obligation in the UK. For example the PJM capacity auction cost $8 million (£5 million) to administer in 2009[51] in addition to the $10 million (£6 million) per year discussed above. In comparison, Ofgem received £3 million to cover the 2009-10 running costs of the Renewables Obligation and its predecessors. Based on this information it is estimated that a market-wide capacity auction cost could cost between £3-£10 million per year. This would cover the cost of running the auction (not more than the £5 million it costs PJM) and some additional monitoring of the market (this would be less than PJM's £ 6 million monitoring costs because the GB market is half the size of PJM and Ofgem already undertakes some

[50] The range of the benefits are proportional to the range of the assumed benefits in paragraph 94 above
[51] EMR team communication with Monitoring Analytics, Pennsylvania.

market monitoring). A targeted capacity mechanism is inherently less complex, so we would anticipate it would cost less.

104. *Risks from system gaming (market manipulation)*: All capacity mechanims are complex, which puts them at risk of potential gaming. In theory, it would be possible to withhold capacity from the energy-only market, while getting a capacity payment so driving up the energy-only price. This would be avoidable for tender options which only affect a small part of the market, i.e. the targeted capacity mechanism, and where there is obligation to be available to the System Operator. All other options would be more difficult to completely prevent gaming, but feasible with some a combination of mandatory bidding and *ex post* regulation. This has been successful in PJM and ISO-NE. It would be easier with an energy market Pool, however e*x post* checks within a bilateral framework could be sufficient.

105. Risks of double payments: The capacity intervention introduces an additional revenue stream to generators, which risks overcompensation. A reasonable assumption would be that competition should tend to drive the electricity price down to the SRMC of the marginal plant, and this is supported by experience in PJM. However, double payments are particularly likely if there is no link between capacity revenue and energy revenue, so much depends on actual CM design. For example to reduce double payments, reliability options would perform well because the link between capacity and energy is very explicit. Capacity payments, auctions and tenders can introduce this link administratively through incorporating an effective offset mechanism. A targeted CM would perform relatively well because it can incorporate clear conditions on when and for what price energy is sold by the resource.

106. *Risks from unintended consequences:* A capacity mechanism is a significant intervention. It therefore has an inherent risk of unintended consequences, as demonstrated by previous experiences in GB with the pool system and internationally. These will vary according to design and market experiences as follows:

a) Payments are relatively simple, there is some experience of them but they are a big change. Obligations could be introduced in an incremental way, drawing on significant experience, for example the renewables obligation.

b) Auctions are complex, but there is good experience of them, particularly in PJM and ISO-NE and they are an extension of National Grid's current STOR arrangements (albeit an order of magnitude increase).

c) Reliability options are complex, untested and cannot be introduced incrementally.

d) A targeted CM is based on existing experience (Sweden's PLR market and GB's STOR arrangements) and affect a small part of the market, so the risk is lower. It has been successful in Sweden since 2003, which is relatively similar market to the GB market.

107. It is not possible to quantify these costs at this stage as much will depend on mechanism design and some detail is likely to be available following the EMR consultation. Moreover administrative costs are dependent on interactions with other EMR options and there is likely to be some benefits from co-ordination in this area.

108. Whilst it's not possible to quantify these costs, to get an understanding of the scale of the costs the analysis suggests that as a proportion of the allocated capacity payments, if the Government were to get the scheme 95% correct, that is have a 5% error (which if we assume captures all the potential market distortions) then the PV of costs of this for a market-wide CM would be around £3bn. In comparison, for a targeted CM an error level of 5% in getting the mechanism correct would amount to costs in PV terms of around £0.9bn.

8.0 Summary of cost and benefits

109. This section summarises the analysis above and qualitatively sets out the main costs and benefits for each of the options.

Option 1 – Do nothing (counterfactual)
Option 2 – Improve the energy-only market: No capacity mechanism

110. These options preserve current market arrangements and option 2 would enable peak prices to be more cost-reflective so helping ensure a level of return to generators, however some of the risks to investment and security of supply will remain. The most significant costs and benefits are as follows.
- Decarbonisation: May be limited in scope for enabling demand side response and other low-carbon balancing technologies.
- Security of supply: Improves investor returns, so increasing margins, but with limited impact as it does not tackle investor certainty in the returns. Would not smooth-out margins.
- Cost: Low risk of paying for more than optimal levels of resource as most decision-making and risk are left with market participants. Low risk of double payments, gaming, complexity. High cash-out prices may impact disproportionately on small suppliers.
- Durability: Low risk of unintended consequences, flexible to respond to future changes
- Ease of transition: Low risk of investment hiatus, and compatible with existing bilateral trading and institutional arrangements.

Option 3: A market-wide capacity mechanism

111. These options are a significant change to current market arrangements but seek to provide sufficient and certain returns to all resources. The most significant costs and benefits are as follows.
- Decarbonisation: Should enable demand side response and other low-carbon balancing technologies.
- Security of supply: Improves both investor returns and investors certainty of returns, so increasing margins and giving a good degree of confidence that they will be maintained. However, no guarantee that it will be the 'right type' of capacity.
- Cost: All options have some risk of paying for more security than is optimal, but a market-wide CM with administratively set payments has a particular risk of incorrectly setting the payment-level. Capacity obligations have a higher risk of double payments and gaming because of the lack of transparency. All options would require a significant level of policing and administrative complexity.
- Durability: This is a significant change and so there is a risk of unintended consequences, this is particularly significant for reliability options which are untested.

- Ease of transition: It would be possible, though difficult, to implement these options within bilateral trading arrangements. Auctions may potentially require different institutional arrangements.

Option 4: A targeted capacity mechanism

112. These options are a more moderate change to current market arrangements, in that they build on existing functions, although it would still require the Government to intervene and determine centrally the level of capacity for the electricity system (thereby transferring the risk of insufficient capacity to meet demand). They ensure sufficient revenue certainty for peaking plant, assuming that the market functions effectively for other plant. The most significant costs and benefits are as follows.
    - Decarbonisation: Should support demand side response and other low-carbon balancing technologies.
    - Security of supply: Improves investor returns and, for peaking plant, investor certainty of returns, so increasing margins. It is more targeted and so better chance of getting the 'right' sort of capacity. However, risk that if implemented poorly, it may lead to some market distortion and so lower margins.
    - Cost: Some risk of paying for more security than is optimal. The intervention is relatively small and so the degree of double payments, gaming, policing and administrative complexity should be relatively low. By being more targeted it could avoid windfalls.
    - Durability: Relatively low risk of unintended consequences, flexible to respond to future changes
    - Ease of transition: Low risk of investment hiatus, and compatible with existing bilateral trading arrangements, and potentially with institutional arrangements.

9.0 Preferred policy option

Rationale for recommending a targeted mechanism

113. While making incremental reforms to the current system is expected improve returns on new generation investment, there is a risk that there will be too few long-term contracts developing between generators and suppliers to give sufficient revenue certainty for peaking plant or, at best, an even greater reliance on vertical integration. Therefore, we judge that this option does not provide a materially higher degree of confidence, versus the *status quo,* that security of supply will be maintained towards the end of the decade or beyond.

114. Options in which a central mechanism sets price seem preferable to a capacity obligation since there is greater price transparency, it reduces barriers to entry and there are fewer implementation issues. Options in which volume is set, rather than price, seem preferable as they reduce the risk of either setting the price too high or ending up with too little capacity.

115. The Redpoint analysis suggests that implementing either a market-wide or targeted capacity mechanism would provide a sufficient level of confidence that security of supply will be maintained. A market-wide capacity mechanism is attractive as it has a lower risk of market distortion. However, on balance, we believe that implementing a targeted mechanism is preferable because of the following:

- The net welfare effect and the qualitative analysis suggests that the targeted CM would better deliver against the EMR objectives whilst ensuring the costs to society are minimised.
- It allows targeting of specific types of capacity and is more likely to deliver capacity of the requisite flexibility and responsiveness, whilst a CM for all may to lead to only life extensions of existing plant.
- It allows learning from both our own market and from international markets that are also decarbonising as to how to deal with intermittency.
- Less risk of blanket windfalls to existing generators.
- Significantly less disruption to current market arrangements.
- Quicker to implement, so we would be in a position sooner to respond to any unexpected supply shortfall
- It gives the market an opportunity to innovate to deal with the revenue uncertainty.
- The shortfall in capacity between what we need and what the market will provide is small (around 3 GW on average would raise margins to around 10%). So this approach is a proportionate response to the scale of foreseeable problem.

Part C - Options for incentivising investment in low-carbon generation

1.0 Introduction

1. This part of the IA considers the impacts of the options for incentivising investment in low-carbon generation. It is broken down into the following sections:
   - Section 2: Rationale for government intervention;
   - Section 3: Options for reform;
   - Section 4: Risk transfer under each option and rationale for risk transfer.
   - Section 5: Costs and benefits of the options when used in isolation, in terms of decarbonisation, economic efficiency, distributional impacts, barriers to entry and competition and security of supply;
   - Section 6: Costs and benefits of combining the various decarbonisation mechanisms into packages along with combining them with the preferred capacity mechanism (a targeted capacity mechanism – see security of supply IA).
   - Section 7: Risks, including:
     - Risks of regulatory failure (7.1)
     - Robustness under different fossil fuel scenarios (7.2)
     - Reduced investor certainty in the carbon price support mechanism (7.3)
     - Potential for market manipulation (7.4)
     - Robustness under a higher electricity demand scenario (7.5)
   - Section 8: Stability and durability
   - Section 9: Transition issues including any possible hiatus in renewables investment;
   - Section 10: Macroeconomic impacts
   - Section 11: Impacts on business
   - Section 12: Devolution issues
   - Section 13: Availability of finance for the electricity generation sector between 2010 and 2030 along with the potential benefits of the options on the availability of finance.
   - Section 14: Other specific impact tests
   - Section 15: Summary and conclusions

2.0 Rationale for government intervention

2. Whilst the UK is on target to reduce its greenhouse emissions in 2020 by 34% on1990 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 2020s, particularly if it is to play its part in decarbonising the heat and transport sectors in the 2030s and beyond.

3. However without government intervention, various commentators including the Committee on Climate Change (CCC) suggest that the UK will not be on the right decarbonisation path to 2050. Their analysis suggests the need for 30-40GW of low-carbon capacity to be built during the 2020s to replace ageing capacity and meet demand growth. The CCC argues that current market arrangements are highly unlikely to bring forward sufficient investment.[52]

4. Modelling for the EMR project by Redpoint Energy suggests that the emissions intensity in 2030 under a 'do nothing' scenario will be around 200gCO_2/kWh compared to an intensity

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

of around 100gCO_2/kWh recommended by the CCC in 2009[53] and recently revised down to 50gCO_2/kWh in their fourth carbon budget report (published December 7, 2010).

5. The EU ETS is designed to address the negative externality of carbon dioxide emissions and factor the price of carbon into the development and operation of electricity generation assets. The system has achieved certainty over EU net emissions from the sectors it covers, including power generation. However, it has not provided long-term certainty in relation to the future carbon price. Whilst there is evidence that investors are beginning to factor in the carbon price into investment decisions[54], there is uncertainty about how carbon prices will evolve and a question of whether the EU ETS carbon price is strong and stable enough to drive the decarbonisation required.

6. The way that the electricity market functions and specifically the way that the electricity price is set presents a particular challenge for investment in low-carbon generation. The electricity market is distinct in that the price is set by the marginal costs of marginal, flexible, generation. 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.

7. 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.

8. Under current market arrangements, a market has developed to manage these risks through long-term contracting (ie Power Purchase Agreements or PPAs). However these contracts are only available for certain technologies (eg wind) and are unlikely to be available for others (eg nuclear) largely due to the large volume of electricity that would be generated by an individual plant[55]. Even where a market has developed for these contracts, there is still a rationale for government interventions. This risk presents particular problems for low-carbon projects that have very high capital costs such as nuclear and CCS.

9. The third reason for government intervention is uncertainty arising in the low-carbon transition. This uncertainty for investors is driven by a combination of technology uncertainty and policy uncertainty. There is a reason for government intervention where government has, or is likely to have, more information or certainty about policy and policy objectives than industry in this transition to a low-carbon electricity system.

10. The analysis in section 13 demonstrates that the current investor base in the electricity sector is unlikely to be able to finance the scale and pace of investment needed to meet the UK's decarbonisation and renewable objectives. This analysis also suggests that the options for reform have different impacts in terms of attracting additional investment into the sector. This is another potential rationale for government intervention.

11. There are also some issues relating to the way the current RO system work in terms of driving investment in renewables, which means there would be advantages in moving to a support system that provides greater certainty.

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

[54] New Energy Finance, *Impact of the EU ETS on power sector investments - a survey of European utilities,* 14 December 2009.

[55] Based on discussion with industry experts

12. There are therefore four possible reasons for government intervention: firstly to strengthen or complement the carbon price signal; secondly to address the inherent bias towards price-setting (largely fossil-fuel) plant in the current system; thirdly to address uncertainty in the low-carbon transition; and fourthly to address the need to attract new sources of finance.

3.0 Options

13. The options detailed below have been considered in the first part of this impact assessment. This list of reform options was agreed at the outset of this project. There are options for the detailed design of these individual options, some of which are mentioned here, that will be considered in detail in the White Paper following the consultation (detailed options for carbon price support are considered separately in the carbon price support consultation).

Decarbonisation: option 1 – Premium payment for all low-carbon generation

14. Under this option, a system of premium payments would be introduced for all low-carbon generation. There are various ways this could be implemented in practice such as through a low-carbon obligation, similar to what is currently in place for renewables. The key feature is that low-carbon generation receives a static premium payment on top of the wholesale electricity price.

Decarbonisation: option 2 - Carbon price support

15. Under this option, a mechanism would be introduced to support the EU ETS carbon price through the tax system, so that the combined carbon price achieves a predetermined level. The mechanism by which this could be achieved, along with the wider impacts of carbon price support (CPS), are considered in the separate HM Treasury/HMRC consultation document on carbon price support.

16. The key feature for the purposes of this impact assessment is how it affects investment. CPS has two indirect impacts on investment in low-carbon generation: firstly it makes investment in unabated fossil fuel generation less attractive in comparison to low-carbon generation and secondly it reduces uncertainty about future returns (by reducing uncertainty about the carbon price). Under this option it is assumed that the RO is retained to bring about investment in renewables, in line with the EU target.

17. CPS targeting a total carbon price (EU ETS plus CPS) level of £50/tonne in 2020 was chosen as this achieves a similar level of decarbonisation in 2030 as the other options and therefore makes it comparable in terms of the level of decarbonisation. This level of CPS is not considered in the CPS consultation document. The impact of other illustrative levels of CPS covered in the carbon price support consultation were also considered as part of the Redpoint modelling (targeting an overall level of £30/tonne and £40/tonne in 2020).

Decarbonisation: option 3 – Emissions Performance Standard

18. Under this option an emissions performance standard (EPS) would be used to restrict high carbon generation; an EPS does not target low-carbon investment directly. There are various design options for this mechanism, including whether it is an annual emissions limit per unit of output on a individual plant or a limit on emissions per unit of output from a group of plant. Under this option it is assumed that the RO is retained to bring about investment in renewables.

19. The EPS considered here is an extreme version of an EPS, as this is required to drive decarbonisation on its own. A more targeted approach has also been considered for use

when the mechanisms are used in combination (see section 6). This approach is to act as a regulatory backstop to prevent the construction and operation of the most carbon-intensive form of power generation.

Decarbonisation: option 4 - Contract for difference for all low-carbon generation

20. Under a system of contracts for difference (CfD), all new low-carbon generation receives a guaranteed price for the electricity that they generate, defined by the 'strike price' of the CfD. The CfD would be settled against an indicator of the average electricity price. Should the average electricity price be higher than the CfD strike price in any particular period, the generator would pay back the difference to the agency managing the scheme on behalf of government. Should the average electricity price be lower than the CfD strike price, the generators would receive a payment from the agency to make-up the difference.

21. A CfD does not mean that a generator has a guarantee that someone will buy the electricity (known as guaranteed offtake).

22. As with the premium payment system, the key feature of a CfD is that generators would still receive their revenues from the electricity price and this provides them with an incentive to respond to prices. For example it provides them with an incentive to generate when prices are high. The amount generators receive through the CfD is dependent on the average electricity price and is not affected by the revenue they receive from the electricity price[56]; their incentive to maximise the revenues through the electricity price is the same as in other mechanisms that retain the link to the electricity price. However, under the CfD, generators are not exposed to the long-term electricity price risk.

23. There are various options for implementation including the period over which the CfD is settled (eg annual). Another important design issue is the reference price against which it is settled. These detailed design issues will be considered in full in the impact assessment accompanying the White Paper.

24. Further details of how a CfD could work are provided in Annex 4.

Decarbonisation: option 5 – Fixed payment for all low-carbon generation

25. Under this option, all new low-carbon generation would receive a fixed payment for a set number of years, e.g. 20 years. The agency signing the fixed payment contract agrees to buy all the electricity generated at an agreed price. The generator would not receive any revenue from the electricity price.

26. There are various options for policy design such as whether it is paid on output and/or availability (capacity); there are similar design issues for both premium payments and CfD.

27. Electricity from generators receiving a fixed payment would need to be fed back into the system in some way. There are various options for doing this, such as through a pool or an obligation on suppliers. These different implementation options are not considered in this impact assessment.

Options for setting the incentives

28. This impact assessment does not consider in detail the possible ways that the incentives for low-carbon generation could be set. With premium payments, fixed payments or with CfD, there are various options: it can be set either by government or through an auction.

[56] This assumes that the actions of the generators do not affect the average electricity price

29. Auctions are in principle the most economically efficient way of setting incentives if there is sufficient competition. Further details of how an auction system could work, along with some examples of its practical application are provided in annex 5.

30. Another key policy design feature is whether the incentives are set centrally for all types of low-carbon generation, as under the RO with different levels of banding for groups of technologies (eg offshore wind), or through contracts with individual generators. This is particularly important in terms of the incentives it provides for generators and the administration costs.

4.0 Transfer of risk under options and the rationale for risk transfer

31. Consideration of how the different options transfer risk is critical as this risk transfer drives many of the costs and benefits of the options. Each one of the options, apart from EPS, transfers revenue risk away from low-carbon generation and gives them more certainty in their returns. This should in principle lead to lower financing costs and more likelihood that any particular project will proceed.

32. This risk transfer is only an overall net benefit to society if the risk allocation is made more efficient than under the current market arrangements. Revenue risk is made up of price risk, risk that electricity cannot be sold (offtake risk), balancing risk and policy risk[57]. Table C1 below shows which risks are retained by the investors under each option.

Table C1 – Impact of EMR options on revenue risks for investors in low-carbon when compared to the baseline

Element of revenue risk	**Premium payment**	**CPS**	**EPS**	**CfD**	**Fixed payment**
Policy mechanism	Small reduction	Small reduction	Large reduction	Large reduction	Large reduction
Balancing risk	No change	No change	No change	No change	Removed
Offtake risk	No change	No change	No change	No change	Removed
Electricity price risk resulting from:					
Carbon price	No change	Removed	No change	Largely removed	Removed
Fossil fuel price	No change	No change	No change	Largely removed	Removed

Price risk

33. As table C1 shows, fixed payments and CfD are the only options that directly remove electricity price risk from low-carbon generators; a fixed payment completely removes price risk whereas with a CfD, generators are still exposed before the CfD is settled. This risk is transferred to government and ultimately consumers[58].

34. In assessing their exposure to risk, low-carbon generators consider the impacts of changes in the electricity price; under current market arrangements and with premium payments, EPS and CPS, low carbon generators gain if the electricity price is higher than they expected it to be (for example because of higher gas prices) and lose out if electricity prices are lower.

35. Generators developed strategies and systems for managing this wholesale price risk (such as portfolio diversification and trading in financial markets). By definition, there is a cost to managing this risk (which exists whether it is managed by generators or by government)

[57] ie relating to the certainty that an investor attaches to a particular policy mechanism
[58] Assumption is the cost of funding a premium payment, a fixed payment or CfD would be recovered from electricity consumers rather than through general taxation therefore risk is ultimately transferred to consumers

which adds to the overall costs of supplying electricity. For some of the larger electricity supply companies with interests in other areas such as gas, it is possible that the costs of managing these risks are not isolated to consumers of electricity.

36. With fixed payments or CfD, low carbon generators are not affected if the electricity price changes as the price they receive for their electricity is unchanged. The impact of this risk being transferred is that consumers do not benefit from lower wholesale electricity prices (for instance caused by lower gas prices) but equally they are not affected by higher wholesale prices. Note that this is only the case for the part of their bill relating to the fixed payment or CfD. By 2030, the modelling suggests more than half of electricity generated in GB would be covered by a CfD.

Rationale for transferring price risk

37. There are two possible reasons justifications for transferring electricity price risk to government[58]:

- Firstly, to address the inherent bias against low-carbon generation due to fluctuations in the gas price, as discussed in paragraphs 7 and 8 above; and
- Secondly, to reflect the fact that government has more information about the commitment to decarbonisation in the longer term than private actors. In the longer-term, the carbon price will have an increasing effect on the electricity price.

38. A fixed payment or CfD has the potential to embed the electricity prices required in a low-carbon system (including the rising carbon price) into the level of the fixed payment or the strike price of the CfD.

39. This ‘required’ electricity price is driven by both the carbon price and fossil fuel prices, particularly the gas price. The reason for government to ‘embed’ the carbon price into low-carbon revenue is clear given the carbon goals are a Government objective. The reason for government to embed a forecast of the gas price into low-carbon revenue is less clear. The reason for doing this is that in principle there should be a link between the gas price and the carbon price; a change in the gas price should lead to a change in the carbon price; if the EU ETS cap is set at a level that is consistent with the UK’s decarbonisation goals then this change in the carbon price should compensate for a change in the gas price.

40. For example, a reduction in the gas price should in the longer term lead to the development of gas-fired generation in preference to lower carbon generation (which would become relatively higher cost with a lower gas price). Other thing being equal, a reduction in the gas price would lead to a reduction in demand for EUAs in Europe up to around 2020 as gas generation is displacing higher carbon coal generation. However beyond 2020, with a steadily tightening EU ETS cap and less coal generation for gas to displace, the EUA price would start to increase. After 2020, the lack of investment in low-carbon generation, as a result of the lower gas price, would therefore lead to a relatively higher demand for EUAs and an associated higher carbon price . This is based on the EU ETS cap and the associated commitment to carbon goals staying the same irrespective of the gas price

41. If investors do not currently fully incorporate the rising carbon price into their investment decisions, it is unlikely that they would incorporate this impact of a structural shift in gas prices into their decisions.

Balancing risk

42. It is assumed here that fixed payments are the only option that take away balancing risk, although this does depend on the fixed payment system. At the moment any generator has to pay balancing charges if it generates more or less than it said it would at gate closure (one hour before dispatch). If this risk is taken away from a low-carbon generator, it is not removed from the system but transferred; someone else bears the risk. Depending on policy design the risk could be transferred to the system operator, who would have to procure more strategic reserve to balance the system or through some other mechanism for transferring the risk to the remaining generation. In either case, it is ultimately the consumer that bears the risk.

Offtake risk

43. Offtake risk affects technologies in different ways. Low marginal cost plant, such as nuclear and wind, are generally dispatched first. Other low-carbon generation, such as coal or gas CCS and biomass, have higher marginal costs and sit higher up the merit order (they are dispatched later as their marginal costs are higher). Therefore offtake risks for low marginal cost plant will be lower than for higher marginal cost plant. Offtake risk for wind and nuclear will however become more significant as more of each comes on to the system in the 2020s.[59]

44. Again a fixed payment is the only option that removes offtake risk from generators explicitly. This risk is not removed, it is transferred either to government[60] (if Government needs to pay fixed payments for plant that it not being dispatched) or to the residual market (if fixed payment plant has preferential dispatch and the length of time plant operating outside of fixed payment is reduced). Again, in both cases the costs are ultimately met by consumers.

45. In all the other options offtake risk still sits with industry, however CfD provides long term price certainty and therefore the effect of retaining offtake risk is limited. With premium payments the effect of retaining offtake risk is also limited where the level of the premium payment is a high proportion of the overall revenue going to the low carbon plant. The costs of removing longer term price risk is considered further in section 5.3.2.

46. Some, including the CCC have argued that there is a rationale for government bearing offtake risk if it has more information about the public policies that will affect the level of demand for electricity in the future. Examples of this could be Government ambition to move to electric vehicles or efficient electric heating (e.g. using heat pumps).

Policy risk

47. This risk relates to the certainty that investors assign to a particular policy mechanisms. Payments for low-carbon that are based on contracts between government and the generators remove policy risks; there is more certainty about the payments they will be receiving across the lifetime of the project as they would be protected by contract law. The reasons for removing policy risk are similar to the reasons for removing price risk discussed above.

5.0 Cost and benefits

Introduction

48. This section considers the costs and benefits of each option, quantified wherever possible, and broken down into the following elements:

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[59] Poyry, *Impact of Intermittency*, July 2009
[60] Or an agency acting on behalf of government and subsequently to consumers

- Decarbonisation (5.2)
- Economic efficiency (5.3)
- Distributional impacts (5.4)
- Barriers to entry and competition (5.6)
- Security of supply (5.7)

Baseline

49. The baseline here is the same as in part B. The RO remains as the primary mechanism for driving investment in large-scale renewables. In the modelling it is assumed that this leads to a take-up of renewable electricity consistent with the lead scenario of the Renewable Energy Strategy at around 29% of total electricity generation by 2020[61]. It was also assumed that the RO results in a higher level of renewables in 2030 (35%) than in 2020; this is similar to the level in the options for reform and therefore allows the cost effectiveness of the options to be compared to the baseline.

50. Investment in other low-carbon generation is incentivised through the EU ETS. The impacts of the baseline on the take-up of low carbon generation is discussed in section 5.2. The impacts of the options are all compared to this baseline.

51. For simplicity, the baseline was modelled as a system of premium payments for renewables as it is similar in effect to the current RO-based system; there are however some significant differences between these options.

52. The impacts of changing from the RO in its current form to a premium payment for renewables only are limited, because changes to the RO in recent years have given it some of the advantages of a premium FIT, as explained below.

53. The total size of the RO support depends on the level of the Obligation each year, i.e. how many RO certificates (ROCs) suppliers are obliged to present to Ofgem or pay a buy-out fee. From its inception up to and including 2009/10, the RO obligation level was set by 'fixed targets' defined by legislation. These fixed targets were some way above the actual ROCs issued for renewables generation, leading to a high and volatile level of 'buying out' of the obligation and a high recycling fund. This led to a high and volatile ROC value to suppliers (made up of the avoided buyout cost plus the recycling fund per ROC).

54. From 2010/11 onwards, the RO obligation level is set by the higher of the fixed target, and the 'headroom calculation'. The latter is an ex ante calculation (six months before the obligation period in question) of the predicted level of ROCs issued from renewables generation, plus a set percentage, now 10%, known as headroom. Under the do nothing option of retaining the current RO, it would be expected that renewables generation would increase such that the expected ROCs issued plus headroom always exceeds the fixed targets.[62] With the Obligation level, and hence support level, set by the headroom calculation, the expected value of a ROC to a supplier is the buy-out price plus 10%.

55. However, the actual value of a ROC to a supplier in a given year could be different from that expected value, because of an incorrect prediction of the number of ROCs issued due to, for example, higher or lower than average wind speeds (affecting wind output); or new plant commissioning earlier or later than expected. These events would lead to the recycling fund being smaller or larger than expected, and hence the value of a ROC to a supplier being higher or lower than expected. Suppliers purchase ROCs directly or

[61] DECC, *The UK Renewable Energy Strategy*, 2009
[62] Although it may be that for one or two of the early years the fixed target is higher, in general we would expect this to be the case for all the years to the end of the RO in 2037.

indirectly from renewables generators. This uncertainty in the value of a ROC to a supplier can result in uncertainty in its value to renewables generators who are not on long-term contracts. This revenue uncertainty may push up the hurdle rates for financing renewables projects. If the generators have long-term contracts for the sale of their ROCs, the uncertainty in the value to the supplier will push down the price they pay to generators.

56. This uncertainty on the ROC value can be viewed from a societal point of view as comprising two risks: a) of over-estimating ROCs issued in a given period, leading to over-compensation of renewables generation paid for by electricity consumers; and b) of underestimating ROCs issued in a given period, leading to under-compensation of renewables generation, and, if a large enough under-estimate, of an over-supply of ROCs and a ROC price crash. The 10% headroom level was chosen to reduce the chance of an over-supply of ROC to about 1 in 10. Such an over-supply could significantly undermine investor confidence in the system.

57. Nevertheless, the move away from fixed targets to the headroom mechanism described above has greatly reduced the uncertainty in the value of a ROC to suppliers. Moving to a premium FIT would remove all the uncertainty surrounding the level of 'top-up' support to the wholesale electricity price for renewables generators, and remove the risks of over- and under-support, and of a crash in the level of support. There could be some small gains through a reduction in the cost of capital. It would also entail higher administration costs, might lead to a short-term limited hiatus in renewables investment and would reduce the Government's level of control over the overall quantum of renewables support. These costs and benefits are summarised in Table C2.

Table C2 - costs and benefits of moving to a premium FIT for renewables relative to the do nothing option of keeping the RO

Benefits	Costs
Small increase in revenue certainty and revenue value to generators, possibly leading to a reduction in cost of capital leading to a reduction in the cost to the economy of new renewables generation	Increase in administration costs – one-off in setting up FIT system, building understanding in the industry; but also ongoing in managing the cashflows including the levelisation process.
Reduction in complexity of the renewables support system which might lead to a slight increase in renewables investment	Possible limited investment hiatus delaying renewables build, reducing carbon savings
Removal of the annual risk of over-compensation or under-compensation	
Removal of the risk of a support price crash, increasing investor confidence	
Possible broadening of investor base as feed-in tariffs are a more widely used and understood support mechanism compared with an obligation system	

5.1 Approach taken for assessing the costs and benefits

58. The potential costs and benefits of the various option have been assessed through:

- Qualitative analysis by DECC, HMT and Infrastructure UK including stakeholder consultation;
- Qualitative analysis carried out by Redpoint Energy;
- Quantitative analysis undertaken using a dynamic model of the GB electricity market developed by Redpoint Energy which simulates investment and generation behaviour. This model is a simplification of how investment decisions are made in

reality and that the results presented in this impact assessment should be regarded as illustrative of the potential impacts of the options.

59. This impact assessment draws on this analysis. The assumptions used in the modelling were developed through discussion between Redpoint Energy and DECC/HMT/IUK and are detailed below. The output from the modelling has been checked with the qualitative analysis to ensure that drivers of the results are clear and understood; for these reasons it is believed that similar insights would have been obtained if another model of similar complexity and quality had been used.

Modelling assumptions

60. For the purposes of the modelling, it was necessary to make an assumption about the degree of decarbonisation required by the electricity system by 2030 and the evolution of the demand for electricity to 2030. An assumption about the development of renewables in the 2020s was also made. The performance of the options can then be compared where they are all set at a level to meet a particular decarbonisation goal.

61. We have used an indicative goal of $100gCO_2/kWh$ in 2030 to compare the impacts of the different options. This is derived from DECC's published long term carbon values[63], which reflect estimates of the global carbon price in 2030 consistent with an emissions trajectory that will give a reasonable expectation that global temperature increases will not exceed $2^{O}C$ on pre-industrial levels. If all investors had perfect foresight of this price, they would decarbonise to around $100gCO_2/kWh$ in 2030. In our judgement, this provides a reasonable scenario against which to test the options for reform, since the DECC carbon values represent a least cost path to global decarbonisation. This is similar to the figure previously recommended by the Committee for Climate Change[3], although a more recent publication by the CCC recommends a lower figure of around 50g/kWh[64].

62. The modelling assumed a take-up of renewable electricity consistent with the lead scenario of the Renewable Energy Strategy at around 29% of total electricity generation by 2020[65]. In the 2020s it is assumed that the take up of renewable electricity generation would be consistent with a level that is incentivised by the rising carbon price. When investors have perfect foresight of this rising carbon price, the level of renewable electricity in 2030 is around 35%. The modelling assumes that the incentives are set in every option so that this level of renewables is achieved.

63. This approach differs to that used for the carbon price support consultation which, in order to be able to compare between different levels of carbon price support, assumed that the level of renewable support is unchanged from the baseline across different levels of support.

64. EMR options were run using standard central DECC assumptions for fossil fuel and carbon prices and Mott MacDonald estimates for generation costs[66].

65. There is a wide range of possible scenarios for the decarbonisation of the energy system as illustrated by DECC 2050 Pathways work[67]. The assumptions outlined above represent a reasonable scenario, based on current policy objectives, against which to test the options for reform. It does not represent a 'preferred' pathway. The Government has not set a target for the level of decarbonisation required by the electricity sector by 2030. It will

[63] DECC, *Carbon Valuation in UK Policy Appraisal: A Revised Approach,* July 2009 and DECC, Updated short term traded carbon values for UK public policy appraisal, June 2010
[64] CCC, *Fourth Carbon Budget*, 7 December 2010
[65] DECC, *The UK Renewable Energy Strategy*, 2009
[66] Mott MacDonald, *UK Electricity Generation Costs Update*, June 2010
[67] DECC, *2050 Pathways Analysis*. July 2010

be taking decisions on the balance of effort in decarbonisation across all sectors for the fourth carbon budget period (2023-27) in 2011.

66. To be able to compare the costs of the various options for change, the mechanisms in each option were set so that the same level of decarbonisation in 2030 was achieved along with the same level of renewables.

67. The level of electricity demand to 2030 is taken from DECC's June 2010 updated energy and emissions projections[68]. This level of demand is the same for each option. The modelling does not therefore take into account how changes in electricity prices, resulting from the decarbonisation options, affect electricity demand.

Investor certainty

68. In the baseline, it was assumed that investors have no foresight over the rising carbon price and therefore make their investment decisions based on the prevailing carbon price at the time of their investment. This is consistent with views from investors as to how these decisions are made based on discussions between the EMR project team and investors. This is a critical assumption and drives the results of the modelling including:

- It means that the level of decarbonisation in 2030, set for the modelling is not met in the baseline.
- Under premium payments, investors will only invest in low-carbon if the premium payments are set at a level consistent with their lack of foresight of the rising carbon price. This results in excessive rents to these generators when the carbon price subsequently rises.

69. Each policy option provides different degrees of policy certainty for investors. Fixed payments, premium payments and CFD provide a relatively high degree of policy certainty for investors as they would take the form of a contract between Government and industry. The form of this contract will be dependent on policy design.

70. For the CPS option, it was assumed that investors factor in a rising carbon price for five years and then assume that it remains at this level for the remaining lifetime of the project. This is consistent with the assumptions used in the carbon price support consultation. It is important to note that the impacts on investment derive largely from this assumption of greater confidence in the combined carbon price level (EU ETS plus CPS) compared to the EU ETS price alone. It is possible that investors only factor in the carbon price support for a limited period and assume that it then drops back to the prevailing carbon price at the time of investment. Investors will in practice run a range of scenarios and take a view based on the most likely outcome in their view. The impact of less certainty in the carbon price support mechanisms is discussed in section 7.3.

71. It is also assumed that an EPS provides a lower degree of certainty to investors than options where there is a contract between Government and industry.

Limitations of the modelling

72. There are important limitations to the modelling, the five key ones being:

- The administrative costs of both the transition to new market arrangements and the operation. These administrative costs are considered in section 5.4.6.
- The modelling assumes that there would be no short-term impact on investment for those options that represent a major change of electricity market arrangements. In

[68] DECC, *Updated energy and emissions projections*, June 2010

reality, there is likely to be a hiatus, particularly under CfD and fixed payments, as discussed in section 9.

- The modelling also assumes that incentives are set at the correct level. The way that these incentives are set (eg by auction or by Government setting them) will affect the likelihood that incentives are set efficiently. The potential impact of poorly set incentives on the costs to consumers is considered in section 7.1.
- The modelling assumes that there is no limit to available finance. The validity of this assumption is considered section 13.
- The model assumes that there are liquid markets and perfect competition.

73. The modelling does not capture the additional costs associated with the offtake risks being transferred to government under a fixed payment. It can be argued that overall, the costs associated with these risks are higher if government has less information than industry (or is more risk averse) in predicting the level of low-carbon generation required.

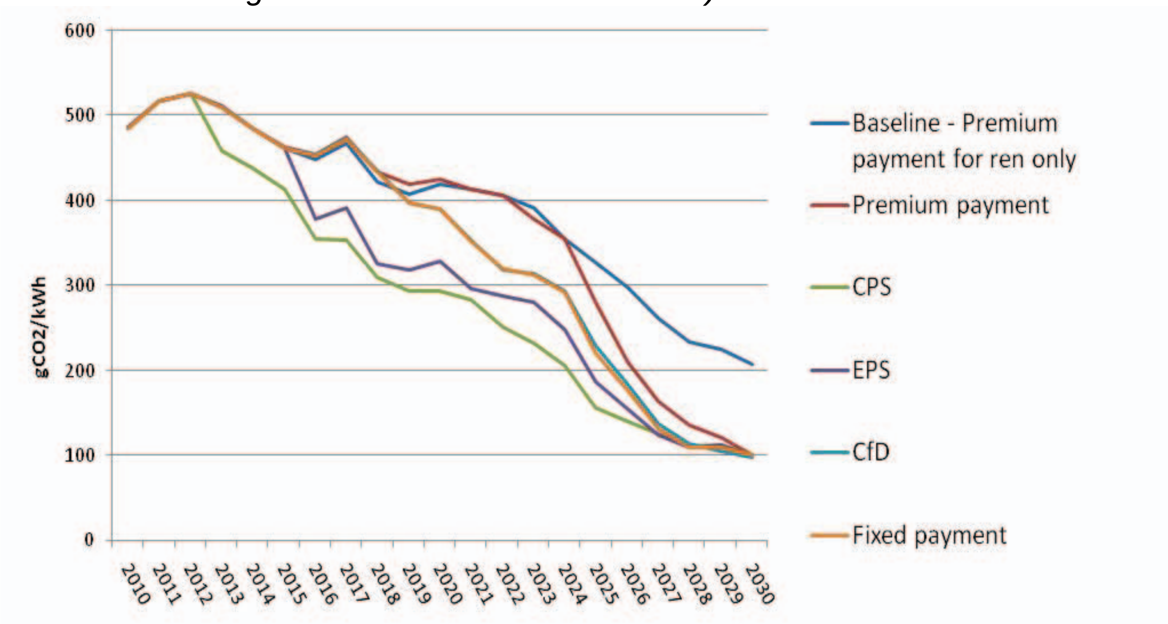
74. It is also important to note that the Redpoint modelling assumed that payments were made based on availability rather than output. The main reason for this was to reduce the distortionary impacts of negative pricing that result from output based incentive payments.

75. The model does not account for any longer term link between fossil fuel prices and the carbon price. The model also does not account for any impact of changes in low-carbon investment in the UK on the long-term carbon price (ie the carbon price is exogenous). If any measures in the UK bring forward investment in low-carbon generation on UK soil that would not otherwise have happened (ie that is not otherwise cost-effective under the EU wide carbon price) it is likely to lead to a decline in this carbon price.

5.2 Decarbonisation

76. The baseline achieved a level of decarbonisation of around 200g/kWh by 2030. The incentives (or the constraint on high carbon generation in the case of EPS and the cost of carbon in the case of carbon price support) in the reform options were set to achieve a level of 100g/kWh by 2030. The characteristics of these options means that the trajectory to this level varies in the different options (see figure C1 below).

Figure C1 - Profile of decarbonisation to 2030 under each option (note that this output from the modelling should be treated as indicative)



77. Carbon price support (CPS) and EPS are distinct from the other EMR options in that they lead to a higher level of decarbonisation earlier, primarily through coal to gas switching, and therefore lower cumulative physical emissions in the UK. Total emissions in the EU will be unaffected given the EU ETS cap on emissions.

78. Under fixed payments and CfD, the modelling suggests that decarbonisation would happen earlier on in the period between 2010 and 2030 than with premium payments; this is because nuclear comes on earlier under these options than with a premium payment. With a premium payment, decarbonisation at the end of the 2020s is rapid relative to the other options.

Table C3 - New build technology profiles under each option (note that this output from the modelling should be treated as indicative)

Option	Base	Prem	CPS	EPS	CFD	Fixed
Year of first new nuclear	2027	2023	2022	2024	2019	2019
New nuclear capacity (GW by 2030)	6.4	9.6	14.4	11.2	11.2	9.6
New CCS capacity (GW by 2030)	0	7.0	0	3.5	5.5	7.0
Retrofit of CCS demos (GW by 2030)	0	2.2	2.2	2.2	2.2	2.2

79. Table C3 shows the key differences in the technology pathways under each options. These results should be treated with caution and seen as indicative of the performance under the different options – a number of reasons why they may differ from this are considered below. However this analysis suggests two key differences between the options:

- Firstly fixed payments and CfD result in more certainty for projects (reflected in lower cost of capital), meaning that nuclear comes on earlier. With premium fixed payments, CPS or EPS, nuclear does not come on until later.
- Secondly premium payments, fixed payments and CfD can be set to allow a mix of technologies to come on to the system. By 2030, 5.5-7GW of new CCS, as well as the demonstration projects come forward. It must be noted that this is not the least cost approach - it would have been lower cost to incentivise a higher level of nuclear. This does though demonstrate one of the characteristics of fixed payments, CfD and premium payments over CPS and EPS – they allows Government to be more directive over the generation mix[69]. It should be noted that all options lead to the retrofit of unabated parts of CCS demonstration projects by 2030.

80. The more complex aspects of company behaviour, where those companies have large portfolios of different types of plant, are not modelled. This is particularly true with respect to the development of a fleet of nuclear power stations. It is possible that a company or consortium developing a fleet of nuclear power stations would, to some extent, be willing to cross-subsidise the earlier nuclear power plants in a fleet. Therefore a nuclear power plant in a fleet may come on earlier than one that was being developed as a single project (as in the Redpoint modelling).

81. It is also important to note that the decision of whether or not to invest in low-carbon generation projects with exceptionally large financing requirements (such as nuclear and CCS), may be more binary than implied by the modelling. There may be no investment in these types of projects until these companies have a higher degree of revenue certainty. It is therefore possible that the modelling underestimates the impact of the options when compared to the baseline.

[69] This could be viewed equally as a disadvantage or an advantage. Under the current policy approach, the Government takes action through the RO to provide support to a range of technologies to give generators an incentive to bring forward a diverse energy mix

82. All the options result in a very similar profile for the uptake of renewables. This is based on the assumption that the policy mechanisms can be finely tuned to achieve a particular level of renewables, which is a strong assumption and difficult to achieve in practice.

5.3 Economic efficiency

83. This section considers the economic efficiency of the options and therefore the overall costs to society including:

- net welfare impacts of giving generators more certainty over revenues (5.4.1);
- the efficiency impacts of insulating generators from the wholesale price signal (5.4.2);
- the impacts on innovation and therefore the efficiency of the system in the future (5.4.3);
- dispatch efficiency (5.4.4)
- air quality impacts (5.4.5)
- administrative costs (5.4.6)

84. There will also be efficiency impacts if the options lead to relatively higher prices for consumers which affects their decisions. Section 5.5 considers the impacts on consumer bills when compared to the baseline, which suggests that these impacts are relatively small. This relatively small change in the prices implies that these options are unlikely to significantly affect decisions by consumers. Costs to consumers could also be affected if generators are able to exert market power; the impacts of the various options on competition are considered in section 5.6. Section 7 considers the risks of regulatory failure, which could also affect costs for consumers.

85. In more formal terms, the following types of efficiency have been considered:

- Productive efficiency: dispatch efficiency (section 5.3.4), cost minimisation incentives (5.3.2).
- Dynamic efficiency: effective entry (section 5.4), cost reducing investment (section 5.3.1), incorporating innovation (section 5.3.3).
- Allocative efficiency where the key indicator is impact on consumer bills (section 6.5) and driven partly barriers to entry and the degree of market power (5.5).

5.4.1 Net welfare impacts of giving generators more certainty over revenues

Impact on costs of capital and resource costs

86. Redpoint modelling suggests that some of the EMR options lead to a reduction in hurdle rates for investors as a consequence of higher revenue certainty[70]. This is an output from Redpoint's risk analysis modelling. Hurdle rates are the rate of return that a project needs to achieve before they are given the go ahead and are directly related to the risks associated with a project and the associated costs of finance.[71]

87. Table C4 shows these derived hurdle rates, while Table C5 shows how the hurdle rate differs between premium payments, CfD, CPS and fixed payments, compared to the baseline. Premium payments only have an impact on hurdle rates for non-renewable technologies given the similarity between the amended RO and a premium payment system. CPS has a relatively small impact on hurdle rates through reducing electricity price uncertainty; for example CPS reduces hurdles rates by 0.5% for nuclear and coal with CCS. EPS has no impact on hurdle rates. The reduction in financing (and hurdle rates) under EMR options is one of the key drivers in reducing technology costs and

[70] driven by an increased ability to debt-finance projects
[71] The modelling assumes that a reduction in the costs of finance are a resource saving, ie an overall benefit to society.

directly related to the reduction in technology costs if the decarbonisation and the technology profiles were identical.

Table C4 – Hurdle rates in Redpoint modelling

Hurdle rates (typical utility)					
	Baseline	Premium	CfD	Fixed	CPS
Onshore wind	8.1%	8.1%	7.8%	7.8%	8.1%
Offshore wind (R1/R2)	10.1%	10.1%	9.6%	9.6%	10.1%
Offshore (R3)	12.1%	12.1%	11.5%	11.4%	12.1%
Biomass	12.1%	12.1%	11.4%	11.4%	12.1%
Hurdle rates (independent developer)					
Onshore wind	9.1%	9.1%	8.1%	7.8%	9.1%
Offshore wind (R1/R2)	11.2%	11.2%	10.0%	10.0%	11.2%
Offshore (R3)	13.3%	13.3%	12.5%	12.5%	13.3%
Biomass	13.3%	13.3%	12.5%	12.5%	13.3%
Hurdle rates (nuclear developer)					
Nuclear	13.2%	12.2%	11.2%	11.2%	12.7%

Table C5 – Reductions in hurdle rates in Redpoint modelling, compared to the baseline

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

88. These results have been compared with empirical evidence of costs of capital for projects[72] under different kinds of risk insulation, which corroborate the baseline figures.

Impact of contractual agreements between generators and suppliers

89. Other evidence suggests that the modelled cost of capital reductions from a move to a fixed payment or CfD may overestimate the benefits. One possible reason for this is that current market arrangements already allow generators to manage wholesale price risk, by entering into contractual agreements (known as Power Purchase Agreements, PPAs) with suppliers, or to transfer this risk to consumers through vertical integration.

90. Under a PPA, a supplier agrees to take the output from an independent generator for a predetermined price, often with a link to the electricity price and/or a cap and collar on the electricity price. To an extent the supplier therefore manages price risk. These agreements are therefore similar to a CfD as described above (though with an offtake commitment) but between industry players rather than government and industry. PPAs typically guarantee offtake for a period of around 15 years; the impact of a FIT or CfD would also therefore depend on the period over which it gives certainty. With PPAs, electricity price risk is transferred from the supplier signing the PPA to government rather than, in the absence of PPAs, from the generator to government.

[72] This evidence was provided in confidence and is not presented here.

91. When introduced into a market where PPAs would have been struck, a CfD would not necessarily alter the hurdle rate of the investment. It would only alter the hurdle rate if the CfD offered:

- More price certainty to the generator: PPAs often have a link to the electricity price and generators therefore still retain some electricity price risk.
- Better counterparty risk: a CfD signed with the government may provide more certainty than a PPA signed with an supplier, those this will be dependent on how the CfD payments are funded.
- Longer contractual period: a CfD may be signed over a longer time period than a PPA.

92. For renewables for example, it is not necessarily the case that moving from the RO to a fixed FIT or CfD amounts to a move from no price risk insulation to full insulation, which is what the Redpoint analysis assumes. The implication of this is that the cost of capital reduction in reality may be lower than that demonstrated by the modelling.

93. However, by taking on the risk of price volatility, suppliers then have to manage this through a variety of mechanisms, including hedging this risk with third parties using their trading desks, passing some risk on to consumers and absorbing the residual risk that remains on their balance sheets. The residual price volatility therefore has some impact on the utility cost of capital. This means that (all else being equal) the introduction of instruments such as fixed payments or CfDs should lower the residual risks on suppliers, because they pass them explicitly on to government and ultimately consumers by committing the latter to long-term fixed price contracts for low-carbon generation. This means consumers should see some of the benefits of accepting these risks, not through reductions in generation hurdle rates as modelled but through a reduction in the suppliers costs or the level of support required to meet a given level of grid carbon intensity.

94. In reality, the cost of capital effect of price certainty will be difficult to distinguish as other risks associated with low-carbon generation (such as planning, construction, availability and performance) may dominate investors' perceptions of project risk, and hence costs of capital.

Net welfare

95. Table C6 summarises the results of the modelling in terms of the change in net welfare under each one of the options between 2010 and 2030[73]. The differences in the technology costs under each option are driven by the different levels of new build along with differences in the financing costs. Running costs are lower with CfD and fixed payment options than with a premium payment as nuclear, which has lower running costs, comes on earlier. Generation costs under CPS and EPS are higher given the higher input costs (fuel) in the 2010s as a result of switching from coal to gas generation. Discounted capital costs of new plant are higher under a CfD/fixed payment given the earlier take-up of nuclear.

96. All five reform options have a negative NPV with fixed payments and CfD/fixed payments performing best with the lowest reduction in net welfare. The negative NPV is due to a variety of factors including:

- The time period over which the costs and benefits are estimated: the modelling only assesses costs and benefits up to 2030, while the benefit to costs ratio increases as

[73] It should be noted that Redpoint apply discounting from year 1, which is different from the Green Book approach. However, as the purpose of this impact assessment is to compare the *relative* cost effectiveness of the options, and the discounting has been applied in the same way across all options, this should neither affect the assessment nor the conclusion.

the carbon price goes up over the period. Therefore if the NPV was calculated over the lifetime of the low-carbon plant, it would be higher. Annex 6 shows how the benefit costs ratio changes over the period, which clearly demonstrates this effect.

- These calculations use DECC's central carbon price estimates, which are consistent with the EU 2020 greenhouse gas target. Prices beyond 2020 increase towards a level consistent with global action required to limit temperature increases to 2^{o}C[74]. If the 2020 EU target was increased to a 30% reduction on 1990 levels rather than a 20% reduction, carbon price estimates would be higher which would in turn improve the overall NPV, because the value of emission savings would be greater.
- As previously mentioned (para 77) under CfD, fixed payments and premium payments, technologies such as CCS are brought on that are not least cost. This reduces the overall NPV in this period but could reduce costs over a longer time frame. The cost of selecting CCS over nuclear described above means that the NPV between 2010 and 2030 is around £2.2bn lower.
- There are other benefits that are not captured in the analysis, including the innovation benefits of bringing forward the development of some technologies. These benefits would also improve the NPV.

Table C6 - Change in net welfare relative to baseline, NPV 2010-2030, £m (2009 real [75]

Option	Premium	CPS	EPS	CfD	Fixed
Value of carbon saved	6,040	15,760	13,080	9,640	9,810
Change in running costs for generation	4,570	-3,360	-3,360	11,530	11,230
Increase in capital costs of new plant	-16,340	-17,500	-17,500	-24,110	-23,920
Change in Net Welfare[76]	**-6,700**	**-5,780**	**-7,710**	**-3,970**	**-3,850**

97. It is important to note that, whilst the level of decarbonisation achieved in 2030 is the same in all the options, the trajectory to 2030 is different (see figure 1). Redpoint estimate that if the technology mix and the profile of decarbonisation were identical, in NPV terms, premium payments would be approximately £4bn more expensive than fixed payments and CfD (ie an NPV of around -£8bn).

98. The modelling assumes that the structure of the industry, in terms of the mix of independent generators and integrated utilities, remains the same over time. It is possible that with new entry into the sector, the structure of the industry will change. This could impact on the costs of capital if less experienced new entrants to the sector have higher costs of capital. This is most likely to affect renewable projects rather than large scale generation projects. This will be the case irrespective of the EMR option but it means that the benefits of fixed payments and CfD may be overestimated when compared to premium payments, though this effect is likely to be small and transitional.

5.3.2 Costs of insulating generators from the wholesale price signal

99. The options affect generators' links to the wholesale electricity price signal in different ways:

- **Fixed payments** insulate low-carbon generation entirely from the electricity price signal.
- Low carbon generation receiving a **CfD** is exposed to variation in the wholesale electricity price within the CfD settlement period, but is insulated from longer-term variations.
- With **premium payments**, generation is fully exposed to the price signal but not on the proportion of its revenue that it receives from the premium payment.

[74] DECC, *Carbon Valuation in UK Policy Appraisal: A Revised Approach*, July 2009
[75] A positive number shows a benefit to society, a negative number a cost.
[76] For simplicity changes in unserved energy, demand side response are not shown as they are relatively small. The increase in CCS demonstration capex is not shown as it is the same in all options.

- With **CPS** and an **EPS**, plant is fully exposed to the wholesale electricity price.

100. There are various potential costs of removing exposure to the wholesale electricity price. These can be broken down into the longer term incentives to build new plant and the operational efficiency signals that it sends to low carbon generation.

Longer term incentives to build

101. Fixed payments and CfD both provide complete long term price certainty for low carbon generation. With these options the decision to build depends on the level of support offered and the quantity of low carbon required. The quantity of low carbon required will be set by the volume of contracts signed by the agency acting on behalf of government. A premium payment is expected to give some certainty over long-term prices, as the support payment acts a floor for prices they receive.

102. In principle, in these options, industry no longer has an incentive to forecast demand; the risks associated with forecasting demand is transferred to government[77]. This means that generators may continue to invest in low-carbon projects even when these projects were not needed, resulting in over-supply of capacity (paid for by the consumer through the support payment regime) and a suppressed electricity price (which is insufficient to reward any generators without a CfD contract, for example fossil-fuel generation which provides flexibility in the mix). Historically, this risk has been well managed by generators, who have been better placed than government to manage this risk. In future, as demand becomes driven by government policy on energy efficiency, electric heat and transport, this balance could change.

103. In practice however, generators with a portfolio of technologies (and in particular fossil-fuel generation) with a diversified portfolio of low and high carbon generation will have an interest in understanding how any investment decisions under a fixed payment or CfD will impact them. In the longer term though as a higher proportion of the generation fleet is low carbon generation, these incentives will become weaker.

104. The difference between fixed payments and CfD is that CfD does not remove offtake risk (as discussed in section 4). This would be the risk that a generator could not find a buyer for their electricity, irrespective of the market price. This risk would be higher where wholesale market liquidity is low.

105. Premium payments retain the long term signals to build the right amount of plant but these signals could be distorted if the premium payment is large in relation to the wholesale electricity price. The larger the premium payment, the more the risk associated with demand forecasting, i.e. oversupply, is transferred to government. As for example, is currently the case with off-shore wind receives approximately 70% of its income from the RO and the rest from the wholesale electricity price.

106. As CPS and EPS both fully retain the link to the wholesale electricity price, the transfer of the management of over-supply risk is reduced in these options.

Operational efficiency signals

107. This section considers the impacts that fixed payments have on the various elements of operational efficiency. These costs are not included in the modelling. Options other than fixed payments largely retain the link to the operational efficiency signals that result from the electricity price and so are not affected by these costs.

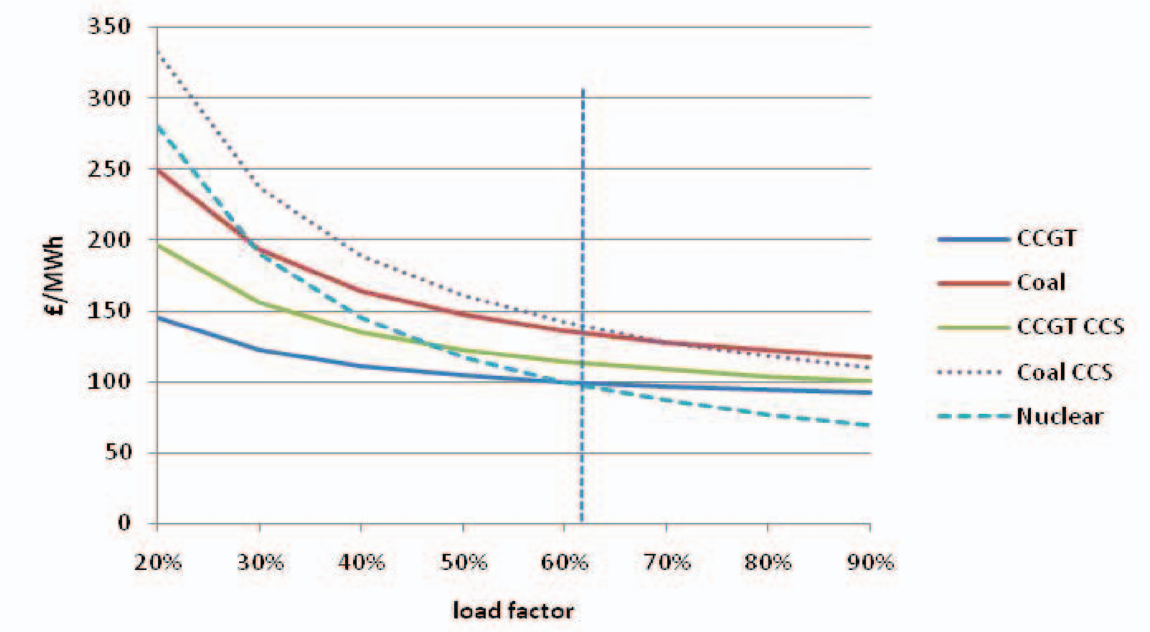
[77] Consumers will ultimately bear this risk; it can be argued that they currently bear at least some of the consequences of this.

Responding to demand

108. Low-carbon generation currently plays a limited role in balancing the system: existing nuclear is generally not flexible: wind is intermittent and not significantly correlated to demand[78] and there is a relatively small amount of biomass.

109. However, nuclear plants being built elsewhere in the world today have load-following capacity built-in, though they can only turn down from 100% to around 30% of capacity and their flexibility is dependent on the stage in the fuel cycle[79]. Coal and gas CCS both have the technical potential to be flexible, though it will be some time before the flexibility is clear in practice. Biomass is a flexible technology. It is therefore possible that many low-carbon technologies will have some role to play in responding to demand to cost effectively balance the system.

Figure C2 – Influence of load factors on levelised costs[80]



110. Whilst low marginal cost nuclear plant will always be most economic to run as baseload, it is possible that at some point in the future it will be the most cost effective plant at lower load factors. This is demonstrated in figure C2 which suggests that nuclear will be more economic than CCGT until the load factor drops below around 60%.

111. It is also possible that at some point in the future, intermittent or inflexible sources of generation will be able to use storage technologies to move their generation output to times of higher demand. This would require the costs of storage to come down significantly from current levels[81].

112. As a fixed payment does not rely on the electricity price to reward low-carbon, flexible plant will have no incentive to respond to changes in the electricity price, potentially resulting in inefficient dispatch and higher costs for consumers. Options that retain a link to the wholesale electricity price, including a premium payment or a CfD, do not suffer from this effect.

[78] Though wind speeds in winter are higher when demand is higher; this could change in the future as demand changes
[79] Based on discussion with the Office for Nuclear Development
[80] DECC analysis based on Mott Macdonald costs estimates based on 2020 project start.
[81] IEA, *Prospects for large scale energy storage*, 2009

113. The wholesale price provides generators with a signal to extend the life of a plant should a capacity shortage result in an increase in the electricity price. This applies to low-carbon generation plant as is does to high carbon plant, although the ability for different types of plant to remain open may be different. Given that a large proportion of low-carbon plant is baseload or intermittent plant, its ability to change its output to capture higher prices is limited; the incentive for fossil fuel plant to stay open longer is stronger. The price signal automatically does this and would do this under a premium payment, CPS or an EPS. Fixed payment and CfD contracts would not do this though contracts could be structured to facilitate this.

Maintenance

114. The wholesale electricity price sends a signal to all generators, not just low-carbon generators, about the best time to carry out maintenance of their plant. This is generally in the summer months when demand and prices are low. Maintenance scheduling can also be constrained by other factors: for offshore wind, it is unlikely that maintenance would be carried out in the winter when conditions are difficult and wind speeds are higher.

115. It may be possible to recreate these market signals in fixed payment contracts. However it should be noted that times of high demand could change in the future particularly with the electrification of heat and transport; this will make it harder to recreate the automatic signals provided by the wholesale price in a fixed payment contract.

System balancing costs

116. Generators have an incentive to forecast output accurately as reducing forecast errors reduces balancing costs. This applies to all types of low-carbon generation, though it is hardest for wind to forecast output. There is evidence that companies are better at doing this than a central agency (as under a fixed payment). An agency can pass on the costs of balancing to suppliers and therefore consumers through system charges, they have limited incentives to make accurate forecasts. A study of the German system found that with an agency balancing the system the costs were €8.3/MWh of renewable electricity compared to an estimate of €3.4-5.4 /MWh[82] . This may be different though in the UK where the system operator works under a different framework and therefore different incentives: in the UK, National Grid operates under a RAB and therefore has an incentive to drive down costs below the baseline costs.

Services of aggregators

117. Aggregators are firms that bring together the output from different independent generators as balancing costs can be managed more efficiently when they are grouped together. Generators have an incentive to reduce the balancing costs by using the services of an aggregator. Aggregators can play an important role in the markets.

Location of plant

118. The wholesale price provides a signal to wind generation to locate in different parts of the country, which may allow them to make the most of higher prices when wind speeds in other parts of the country drop. For other types of generation, location makes no difference to the price they receive in the market (not taking account of network charges or

[82] Klessman et al, *Pros and cons of exposing renewables to electricity market risks – A comparison of the market integration approaches in Germany, Spain and the UK,* Energy Policy 36 (2008)

constraints). In a world with increasing intermittent wind generation, price signals therefore provide a signal for diversity[83].

119. This is a benefit of a link to the wholesale price, though an alternative approach such as a fixed payment could mimic this effect through particular contract clauses. In the future though with higher penetration of wind this effect could diminish as wind reduces the average electricity price.

Other

120. The electricity price may also send other signals to the generation companies, which could result in unintended consequences if the link to the wholesale price is removed.

Summary by technology

121. Table C7 summarises the importance of the wholesale price signal in driving efficiency in both the operation and development of low-carbon generation.

Table C7 – impacts of removing the wholesale price link on the efficiency of the system by technology

	Offshore wind	**Onshore wind**	**CCS**	**Nuclear**
Responding to demand	Low	Low	High	Medium
System balancing costs	Low	Low	Low	Low
Services of aggregator	Medium	Medium	Low	Low
Maintenance	Low	Low	Medium	Medium
Location of plant	Medium	Low	Low	Low

5.3.3 Innovation

122. Options that are technology neutral such as CPS and EPS provide greater rewards for low cost plant and hence may promote technological innovation more than options where long term contracts (CfD, fixed payment and premium payment) are employed.

123. The impacts of CfD, fixed payments and premium payments can be reduced through the way that payments are set and whether they are open to all technologies. An auction system would in principle be open to all technologies and therefore technology neutral. This is clearly heavily dependent 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, are the built-in expectations of the declining low-carbon payments.

124. 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, which is not affected by these options in the same way that baseload plant is. See section 8 for a discussion of the impact of the options on the wholesale electricity price.

5.3.4 Dispatch efficiency

125. CPS and EPS should in principle retain the signals from the market for efficient dispatch, taking into account the price of carbon. Mechanisms that provide targeted payments to specific technologies, such as premium payments, fixed payments and CfDs all have the potential to distort dispatch signals leading to inefficient dispatch of plant.

[83] It is worth noting that there is a correlation between output from wind and times of higher prices as wind speeds tend to be higher in winter when demand is higher.

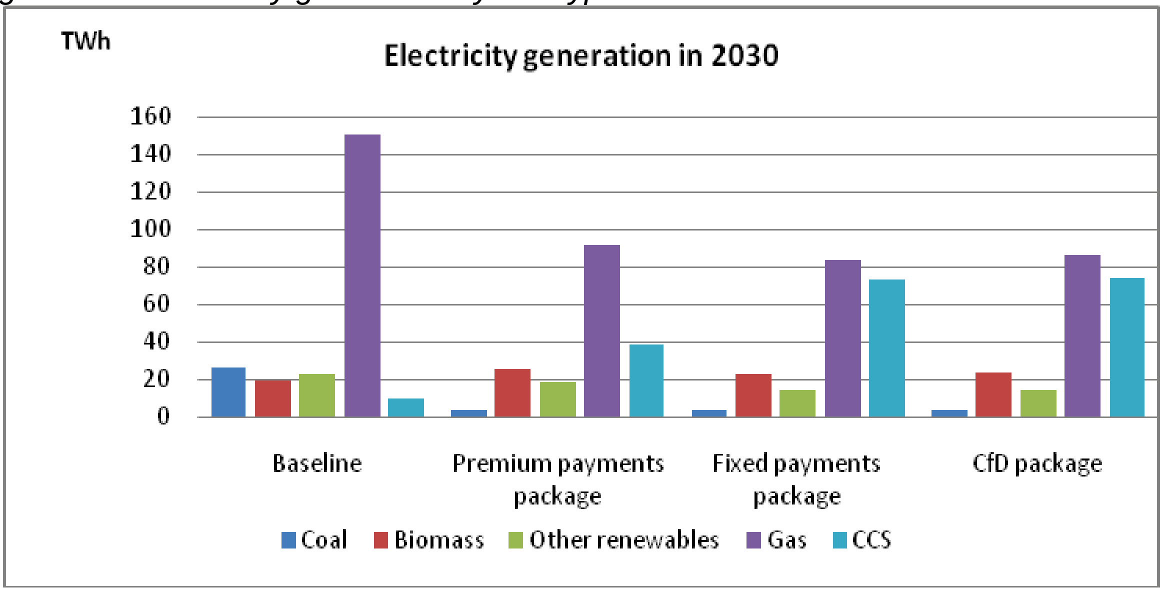
126. With a fixed payment, dispatch signals can be recreated through the way that the electricity is fed back into the electricity system. This is therefore dependent on the ability of an agency to do this. As both wind and nuclear are low marginal cost plant, and therefore likely to be dispatched first, the impacts on the rest of the system are likely to be limited until the penetration this low marginal cost plant is so high that one or other needs to be curtailed which the modelling suggests might begin to become an issue beyond 2025. For other types of low-carbon plant, including biomass and coal or gas CCS, the impacts of inefficient dispatch on the rest of the system are likely to be much more significant.

127. In terms of efficient dispatch, premium payments create similar problems to CfD, though these issues would potentially be easier to resolve.

5.3.5 Air quality impacts

128. The impacts on human health from air quality have been monetised using the Interdepartmental Group on Cost and Benefits (IGCB) damage costs[84]. For the baseline scenario and each option for reform the change in emissions have been estimated using data from the NAEI[85] and these emissions valued combined with electricity generation output modelled by Redpoint[86]. All options for reform consulted on could lead to a reduction in damage cost relative to the baseline by around £400-£1,000m to 2030 (NPV). This reduction in damage costs is driven by less electricity generated from conventional coal plant and some waste technologies in the reform options relative to the baseline[87]. These reductions outweigh the relatively higher emissions and associated damage costs from increased biomass-, other renewables-[88] and CCS generation in all the options.

Figure C3 - Electricity generation by fuel type in 2030[89]



129. The health impacts of air quality impacts depend greatly on the geographical location of the emissions and the height at which the emission occurs. Redpoint modelling does not predict where plants will be located, so several scenarios are assessed.

[84] More information on IGCB and damage costs are available from www.defra.gov.uk/evidence/economics/igcb
[85] National Atmospheric Emissions Inventory www.naei.org.uk
[86] Electricity generation output modelled by Redpoint.
[87] Generation from "non ROC waste" technologies remains the same in all the scenarios
[88] "Other renewables" is made up of "AD on wastes" and "energy from waste" technologies
[89] Redpoint modelling

130. Scenario A assumes that all generation technologies up to 2030 will be located in areas similar to where existing generation plants are currently located. Scenario B assumes this to be true only for conventional fossil fuel and biomass plants (with waste technologies located at sites similar to current industrial locations), whereas scenario C assumes that also biomass generation is located in current industrial areas. Scenario C therefore illustrates the large absolute damage costs occurred in all options should waste and biomass plants be located at current industrial sites.

Table C8 – Impact of options on damage costs relative to the baseline (£m, NPV 2010 -2030)

Scenario	Baseline (absolute)	Premium payments package	Fixed payments Package	CfD package
A	7,934	-491	-568	-546
B	11,460	-860	-1,022	-999
C	13,665	-420	-458	-389

131. Whilst differences in assumption on the likely location of plant greatly influence the absolute damage cost in the different options (c. £8bn to £14bn NPV), all options would lead to a reduction in damage costs, hence an improvement in air quality, relative to the baseline. The fixed payments and CfD packages lead to the highest reduction in damage costs in all scenarios assessed as cumulative emissions in these scenarios are lower.

132. Estimates must be considered as indicative as the damage costs methodology used here only provides an approximation of the potential impacts. A more robust assessment of air quality impact of the different options will be analysed using the full impact-pathway methodology for the White Paper.

5.3.6 Administrative costs

133. The administrative costs implied by any of the options depend on specific policy design, and as such work on refining these is ongoing as part of the consultation process. Given the potential overlap in administrative framework between some of the decarbonisation and capacity mechanism options these are considered together, whereas EPS is considered separately.

134. The payment of premium or fixed payments, as well as the settlement of contracts for difference, could also be administered by a central body. It may be more cost efficient and simplify the implementation framework to make one body responsible to administer both the capacity mechanism and low-carbon revenue support.

Premium and fixed payments

135. Premium payments are likely to be more costly to run than the RO, insofar as they require a separate settlement mechanism. The cost is likely driven by staffing requirements, which depend in turn on the volume of transactions.

Fixed payments

136. Fixed payments will require a separate settlement mechanisms similar to premium payments and from this perspective the administrative costs would be similar to premium payments. However fixed payments will also require a mechanism for feeding the electricity procured through the fixed payment route back into the market. There are various mechanisms for doing this including a pool or an auction system; any system is likely to be combined with an obligation on suppliers.

CfD

137. A CfD is likely to lead to higher administrative costs versus premium or fixed payments as the need to establish the size of and manage payments to and from generators adds some complexity.

138. An implementing body would take on wholesale price exposure as the CfD payments would be inversely related to the average electricity price over the settlement period. The implementing body would also require working capital and bear counterparty risk. Both of these issues would impose extra costs on top of basic administrative costs; the size of the cost could be reduced with regular settlement. Staffing needs will depend on the volume of contracts to be settled and the frequency of settlement.

EPS

139. The administrative costs will be dependent on the regime used to implement the EPS mechanism. If a new permitting regime is required, then this is likely to involve a number of costs, including:

- Setting up of a regime;
- Receiving and verifying application for permits;
- Issuing of and applying conditions to permits;
- Annual monitoring of CO2 emissions; and
- Enforcing permits.

140. In the period between 2010 and 2020, it is not expected that there will be significant applications for new coal-fired power stations, and that the costs of issuing permits (if that method is chosen) will be limited. As the UK moves beyond the demonstration phases of CCS, and into deployment, there may be an increase in applications, which will have a relative cost increase.

141. The alternative approach of an EPS applied aimed at driving decarbonisation when used in isolation, as outlined in section 6, is likely to bring about significantly larger costs. Under a permitting regime, this would require permits to be issued to all existing, as well as new, generating capacity. This would be particularly burdensome in the early stages of implementation.

142. We will be working closely with relevant agencies when designing the implementation of an EPS so, for example, to limit duplication of effort when monitoring CO2 and issuing permits or licenses.

5.4 Distributional impacts

143. As well as technology costs, EMR options also affect consumers and producers through their impacts on the wholesale electricity price. Targeted measures, such as CfD and fixed payments, have limited impact on the wholesale price whereas CPS and EPS have more significant impacts. With a premium payment, incentives will be higher than they need to be if generators do not believe that they will be rewarded through an increasing electricity price (caused by an increasing carbon price). It is not clear in practice whether this will be the case – for example there is evidence that carbon prices are beginning to be factored into investment decisions[54]. The modelling suggests how these effects combine and the resultant impact on consumers.

144. It is also important to note that wholesale prices, and therefore costs to consumers, can be significantly affected by low capacity margins when less efficient, higher costs plant has to be used to balance the system.

145. Table C9 shows how consumer and producer surplus changes in the options compared to the baseline. Consumer and producer surplus are measures of the overall impact of the measures on consumers and producers over the period between 2010 and 2030. As mentioned above, consumer surplus is driven by changes to the wholesale electricity price and the costs of supporting low-carbon generation. Producer surplus is also driven by this and generation costs and changes in applicable taxes (such as CPS). This shows that consumer surplus is lower than in the baseline in the options, with the exception of CfD where consumer surplus is marginally higher. Under CPS producer surplus is reduced due to the revenues to government.

Table C9 - consumer and producer surplus NPV 2010-2030, £m (2009 real) [90]

Option	**Premium**	**CPS**	**EPS**	**CfD**	**Fixed**
Change in wholesale price	-1,260	-30,550	-27,420	610	3,320
Change in low-carbon support	-10,530	7,470	9,810	440	-4,240
Change in consumer surplus[91]	**-12,020**	**-23,020**	**-17,500**	**760**	**-1,150**
Change in wholesale price	1,260	30,550	27,420	-610	-3,320
Change in low-carbon support	10,530	-7,540	-9,690	-430	4,270
Change in generation costs	-6,470	-28,200	-7,820	-3,680	-3,620
Change in producer surplus	**5,320**	**-5,180**	**9,910**	**-4,720**	**-2,670**

Costs to consumers

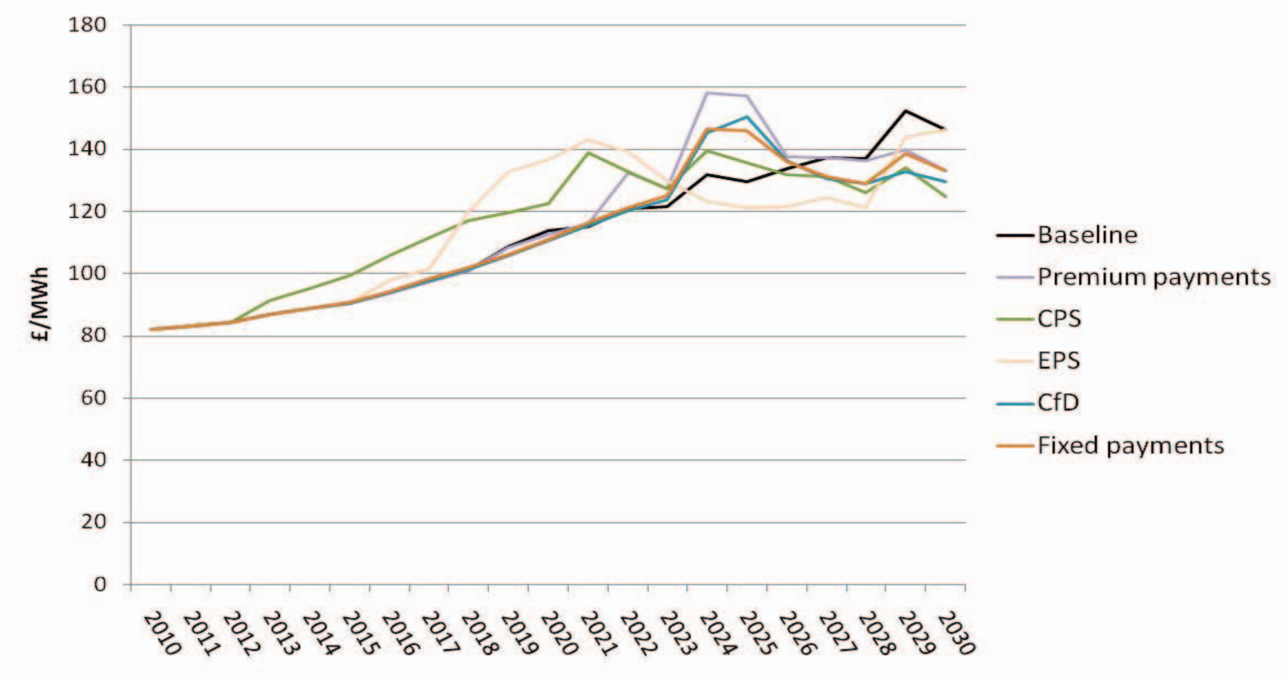
146. Figure C4 shows how costs to consumers (wholesale price plus the support costs) change over time[92]. This suggests that costs to consumers under CfD and, fixed payments and premium payments are relatively low compared to CPS and EPS until the early 2020s, but still higher than the baseline. It also suggests these costs are more stable under fixed payments and CfD than premium payments; this is because the costs associated with low-carbon support are stable. By 2030, consumers are better off under all options than under the baseline.

147. It is worth noting that costs to consumers are lower under CPS than in any of the other options towards the end of the period. This is due to the high penetration of low marginal cost low-carbon plant, which begins to pull down the average wholesale electricity price. This is particularly marked with CPS as the wholesale price is the main driver of investment in low-carbon in the 2020s. This effect on the wholesale price, and the perceived benefits under options that retain the wholesale price as the main source of revenue, should be treated with caution; this is because it is likely to be an illustration of the wholesale market beginning to become unsustainable in terms of driving further investment in low-carbon plant. This effect is discussed further in the section 7 on stability and coherence.

148. These figures should be treated with caution as they can vary significantly from year to year and are partly driven by changes in the capacity margin which can increase the electricity price significantly in any one particular year. For example the spike in costs to consumers in the mid 2020s, particularly with fixed payments, CfD and premium payments is largely due to a lower capacity margin.

[90] A positive number shows a benefit to consumer (or producers), a negative number a cost.
[91] For simplicity expected energy unserved, change in demand side response, change in CCL and change in VAT are not shown as these are relatively small.
[92] Note that consumer bills are made up of these costs plus other costs such as network charges.

Figure C4 – Costs to consumers in EMR options when used in isolation



149. The other elements that make up consumer bills (including transmission, distribution, consumer funded energy efficiency and distributed energy schemes) are likely to be broadly similar across the options[93]. Table C10 shows the impact on consumer bills of the various options, along with the average impact on bills over the period. This suggests that CfD are likely to minimise the impacts on consumers bills overall.

Table C10 – Impact of options on annual electricity bills for both industrial and domestic customers

Option	**Baseline average**	**Premium**	**CPS**	**EPS**	**CfD**	**Fixed**
Domestic						
2010	£493	0%	0%	0%	0%	0%
2011-2015	£477	0%	3%	0%	0%	0%
2016-2020	£497	0%	8%	9%	-1%	0%
2021-2025	£559	8%	7%	5%	4%	4%
2026-2030	£682	-2%	-6%	-5%	-4%	-4%
Average 2010-2030	£551	1.5%	2.1%	1.8%	-0.4%	-0.1%
Non-domestic (£000)						
2010	£918	0%	0%	0%	0%	0%
2011-2015	£948	0%	4%	0%	0%	0%
2016-2020	£1,152	0%	11%	12%	-1%	0%
2021-2025	£1,401	10%	8%	6%	5%	5%
2026-2030	£1,564	-2%	-7%	-5%	-5%	-4%
Average 2010-2030	£1,250	2.0%	2.9%	2.6%	-0.4%	-0.0%

5.5 Barriers to entry and competition

Background

150. Current market arrangements have resulted in barriers to entry; these are reflected by the reduction in market liquidity since bilateral trading was introduced through the New Electricity Trading Arrangement (NETA) in 2000.

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[93] There could be relatively small differences caused by different take-up of technologies

151. In June 2009, a report by Ofgem[94] found that liquidity in the electricity market in Great Britain was lower than other energy and commodity markets, including a number of European electricity markets:

> ' Liquidity in the GB electricity market (as measured by churn rate) has fallen from a high of around 7 in 2002 to around 3 in 2008. It has been argued that this was in part due to the significant vertical integration and consolidation in the industry following the collapse of Enron (and others) and the withdrawal of a number of previously active market participants.'

152. The availability of 'shaped' products[95] is particularly important in well developed wholesale markets especially for those market players who are not vertically integrated. Non-integrated players have to manage the "shape risk"[96] relying on wholesale markets. Responses to Ofgem's discussion document[97] (looking at options for addressing lack of liquidity) noted that small suppliers face challenges in acquiring volumes less than 1MW in size and in shapes suitable for retail positions rather than the standardised trading products. The responses indicate that there is liquidity in the prompt markets for these shaped products, actively supported by a number of brokers. However, there is limited forward liquidity in shaped products. The market for individual days (other than day-ahead), is very illiquid.

153. This lack of liquidity is an indicator of the degree of market concentration: whilst there are 45 generation companies in the UK, the top eight generate over 99% of all electricity produced. Levels of generation capacity for these larger firms has been increasing since 2000, and most have had an increase in capacity in the latter half of the 2000s.

154. Independently of EMR, Ofgem has laid out four potential policy interventions to improve liquidity under the current market arrangements; a decision on whether to pursue one of these will depend on an assessment of progress in the wholesale market:
    - An obligation requiring large generators to trade with small/independent suppliers.
    - Market-making arrangements, where the large vertically-integrated utilities would be obliged to provide electricity to an agent who would make this available to other market participants.
    - Mandatory auctions supported by an obligation on large generators to offer volume.
    - Self-supply restrictions on the large vertically integrated market players.

155. There is also a reason for government to intervene in the electricity market to address the barriers to entry resulting from a lack of wholesale market liquidity described above . Whilst liquidity and barriers to entry is not the primary focus of this project, the options considered have an effect on both. In some cases, the scale of the costs and benefits, as well as ease of implementation, are dependent on liquidity in the market. The effect of CfDs in particular will be much more positive on enabling new entrants if corresponding measures are taken to increase liquidity on the exchange, so that new entrants have a viable alternative to selling under PPAs to the incumbent suppliers.

Impact of options

156. Options considered are likely to have a positive, but for some limited, impact on barriers to entry to the electricity market. By reducing the barriers to entry they can potentially

[94] Ofgem, Liquidity in the GB wholesale energy markets, 8 June 2009
[95] Shaped products are packages with varying amounts of electricity over a given period
[96] The price risk associated with variations in their off take over the course of the day.
[97] Ofgem, Addressing Market Power Concerns in the Electricity Wholesale Sector - Initial Policy Proposals, 30 March 2009

improve competition by increasing the number and range of suppliers in the electricity market, and also potentially improve liquidity. It is not envisaged that the options would negatively affect market participants' ability to compete in the market.

157. This section considers the barriers to entry arising from revenue risk and how the various options for reform address these barriers. There are significant other barriers to entry associated with the size of company required to undertake some types of multi-billion pound investment (eg CCS or nuclear). These other barriers to entry are likely to dominate in the case of these types of generation projects; any attempt to address revenue risk is unlikely to significantly promote new entrants, though it may encourage additional capital to come forward (see section 13).

Carbon price support, premium payments and EPS

158. Although they reduce the cost of capital premium payments and CPS will have limited impacts on barriers to entry as they retain the current market structure. Generators are still exposed to electricity price risk, offtake risk and balancing risk. Vertically integrated companies are better placed to manage these risks given both the size of their portfolio and their link to a relatively price insensitive consumer base.

159. As these options reinforce the use of the wholesale market, they can be expected to have a limited positive impact on liquidity.

Fixed payment

160. A fixed payment significantly reduces barriers to entry resulting from revenue risk as it removes price, offtake and balancing risk. This is particularly significant for independent renewables developers. It also therefore largely removes the incentives for vertical integration. In the long term this may mean that more fossil-fuel electricity is traded on the market which will improve liquidity.

161. Market liquidity could be affected where the low-carbon is taken out of the overall wholesale market as the volumes of electricity traded will be lower. The electricity would instead by fed back into the system. However the generation that would be taken out the market and covered by a separate revenue stream will be low marginal cost plant which is unlikely to be setting the price. Therefore whilst the volume of transactions will be lower under a fixed payment, the quality of the price signals (and therefore liquidity) will not necessarily be affected.

162. The overall longer term impacts of a fixed payment on liquidity are therefore ambiguous.

CfD

163. It can be argued that a CfD reduces the barriers to entry arising from revenue risk as price risk is removed from the generator though generators would still be exposed to offtake and balancing risks, which are significant particularly for independent generators. Therefore, the impact is likely to be somewhat less than for fixed payments.

164. However PPAs are currently negotiated between independent generators and suppliers (for some types of generation including renewables but also gas CCGT) to remove this risk. The existence of a CFD offered by Government may make it easier for new entrants to access PPAs from suppliers (both parties may be more willing to sign variable price PPAs linked to the wholesale market price rather than fixed price PPAs in particular the generator as they are insulated from long-term price changes through the CfD). If CfDs are backed up by greater liquidity, this could serve as an alternative route to market for new entrants.

165. CfD are likely to reduce the incentives for vertical integration given the price certainty provided. These impacts will be lower than under a fixed payment as the generators would still be looking to secure offtake and minimise balancing costs.

166. As CfD relies on prices from the wholesale market to settle the contracts, it will reinforce the use of the wholesale market, which should therefore have a positive though limited impact on liquidity.

167. The complexity of CfD may reduce the benefits in terms of reduced barriers to entry. This may change over time as industry becomes more familiar with the instrument.

168. The overall benefits of a CfD on liquidity and barriers to entry could therefore be positive but these benefits could be marginal.

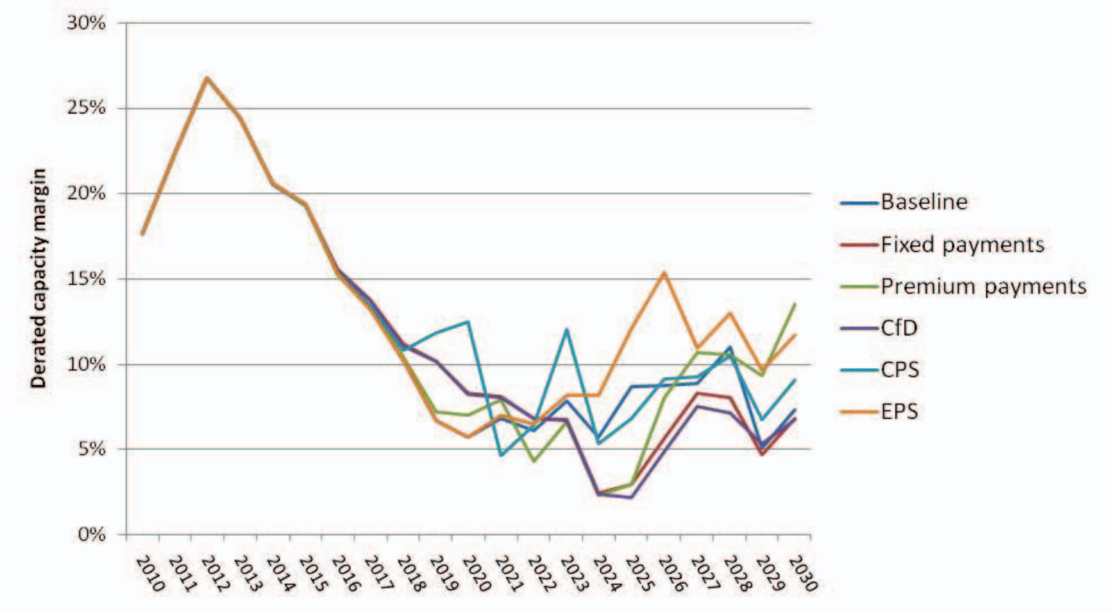
Small Firms Impact Test

169. It is not envisaged that the options considered will have a significant impact on small business, primarily because the participants in the electricity market tend to be relatively large firms. Furthermore, the options would not require small business to comply with new regulation.

5.6 Security of supply

170. Capacity margins under premium payment, CfD and fixed payments are lower than under CPS and EPS (see figure C5). This is largely because wholesale prices are higher to 2020 under CPS and EPS resulting in a higher level of gas capacity (both existing and new) under these options. Capacity margins are lower than the historical average because of the relatively large amount of low marginal cost plant depressing prices, which makes investments in new fossil-fuel generation increasingly uneconomic

Figure C5 – De-rated capacity margins under the various EMR options



171. The decarbonisation options can also potentially have an impact on the diversity of electricity generation. For example premium payments, fixed payments and CfD can be more directly targeted at specific technologies than EPS and CPS and therefore have the potential to result in more diversity of generation, should this be a policy goal whilst acknowledging that a more diverse generation mix will be a more expensive particularly in

the short to medium term. The impacts of a more diverse generation mix in the longer term as technologies develop and mature and prices change is also a key consideration.

172. The results for the EPS are somewhat counter-intuitive: in principle an EPS drives decarbonisation by the electricity price increasing as unabated fossil fuel plant is constrained and capacity margins tighten. However figure B5 shows that capacity margins are relatively high under an EPS. However, whilst the plant is available, resulting in a comfortable capacity margin, it cannot be used because of the EPS. An EPS based on an emission limit per kWh would have a different impact.

6.0 Coherence: combining the options into packages

173. This section considers the costs and benefits of combining the three decarbonisation options that directly target investment in low-carbon generation (premium payments, fixed payments and CfD) with the preferred capacity mechanism (targeted capacity mechanism) to give three possible packages of options. Carbon price support (CPS) was also included in the preferred package of options along with a targeted EPS. The rationale for including CPS and EPS in these packages is described in section 6.1 and 6.2 below. The following three packages are therefore considered here:

- **Package: option 1 –** Premium payment, targeted capacity mechanism, CPS, EPS
- **Package: option 2 –** CfD, targeted capacity mechanism, CPS, EPS
- **Package: option 3 –** Fixed payment, targeted capacity mechanism, CPS, EPS

174. This analysis considers the impact of combining the different mechanisms aimed at incentivising investment in low-carbon generation with a targeted capacity mechanism. It does not consider the impacts of combining these decarbonisation options with different types of capacity mechanism. This was considered in the Redpoint analysis, which concluded that the impacts of the two main types of capacity mechanisms (targeted and market wide) as described in the security of supply options IA) were not significantly altered by the choice of decarbonisation mechanism.

6.1 Rationale for including carbon price support in the packages

175. CPS alone can drive investment in low-carbon generation, whilst at the same time restricting the development and operation of unabated fossil fuel generation. However, the level which CPS would need to be set to deliver all the decarbonisation that is needed on its own would result in a steeply rising carbon price to 2020 (£50t/CO2) that would have potentially significant impacts on existing generators, both low-carbon and fossil-fuel. It would also impose costs on consumers. Therefore using CPS in isolation to drive decarbonisation was not included in the packages and nor is this level (£50t/CO2) considered in the separate HMT/HMRC consultation. The Government has set out that supporting the carbon price should be part of a package of reforms, but that on its own, it was not the answer for reforming the electricity market..

176. Irrespective of the decarbonisation mechanisms, CPS sends important signals in terms of the development and operation of unabated fossil fuel plant. Putting a price on carbon emissions directly tackles the market failure – carbon pricing is at the centre of the Government's overall strategy for reducing the UK's emissions. This in turn sends important signals to investors in low-carbon generation. The discussion below considers the interactions between CPS and the various decarbonisation mechanisms, specifically focussing on the impacts on investment in low-carbon generation.

Premium payments

177. CPS and premium payments are complementary as investors have higher expectations of the electricity price (given that the carbon price feeds directly into the electricity price) and therefore require lower premium payments to proceed with a low-carbon project. In other words CPS reduces the level of the premium payments required. It is also important to note that because CPS provides more certainty around the rising carbon price, the potential for excessive rents to producers and associated higher costs for consumers, is reduced.

178. CPS also provides investors with more certainty of their returns and this leads to lower financing costs for low-carbon projects. The scale of this effect is discussed in section 5.4.1. CPS also re-enforces the "polluter pays" principle.

Contracts for difference

179. CPS and CfD are complementary as the higher electricity prices resulting from CPS reduce the revenues that flow from government[98] to generators when the CfD is settled. As with the premium payment scheme CPS essentially reduces the size of extra support that is channelled through government under a CfD. There are therefore important considerations for public finances as the flows from government to generators would be lower with CPS.

180. CPS has a positive impact on investment decisions when combined with CfD compared to CfD used in isolation: it reduces the liabilities for investors before the CfD is settled as they are getting a higher proportion of their revenues from the wholesale price due to the CPS. CPS and CfD are both therefore contributing to this positive investment decision. This effect is not covered in the modelling but will be a consideration for investors.

181. By targeting only new low-carbon investment, CfD limits the potential for excessive rents to new low-carbon generation, this is one of the key drawbacks of CPS where investors do not have foresight of a rising carbon price. This benefit of CfD is retained when it is combined with CPS.

Fixed payments

182. The interaction between fixed payments and CPS is limited, largely because with fixed payments generators do not receive any of their revenues from the wholesale electricity price. The main impact on investment in low-carbon generation in this option is through its impact on unabated fossil fuel generation – it incentivises operation of, and investment in, lower carbon emitting fossil fuel plant.

Level and profile of CPS used in the modelling

183. The CPS used in the Redpoint analysis targets a total carbon price in 2020 of £30/tonne (the central figure in the range presented in the CPS consultation). This figure was chosen purely for illustrative purposes: £30/tonne was chosen as it more clearly demonstrates the impact of combining the options. In addition, for simplicity the analysis assumes a constant increase of the CPS from 2013 to 2020, but the CPS could be set very low for the initial years to minimise the impact on consumers. The level and profile of CPS are discussed in detail in the separate HMT/HMRC consultation document and accompanying impact assessment on CPS.

[98] or a body acting on behalf of government

6.2 Rationale for including an emission performance standard in the packages

184. This impact assessment also considers the role that an EPS could play in limiting emissions from fossil fuel generation. This is a more targeted EPS as it is being used in combination with other policy mechanisms rather than driving decarbonisation in isolation.

185. An EPS sends a clear regulatory signal to investors in electricity generation, to support the economic signals from the carbon price. It builds on the Government's current policy that developers must demonstrate CCS on a proportion of a coal-fired power stations capacity, and provides a regime under which plant will be expected to operate. It therefore provides an important backstop. Unlike the carbon price, an EPS is not affected by movements in fossil fuel prices and it is therefore potentially more robust in a high fossil fuel price scenario.

Characteristics and coverage of EPS

186. A targeted EPS would be set at a level to prohibit investment in unabated coal-fired power stations. The proposed approach would be to set the EPS at a level consistent with commercial-scale demonstration of carbon capture and storage (CCS), so to provide clarity on regulation and create a clear signal on the need to abate emissions from coal-fired powered stations.

187. All new coal-fired stations are already required to demonstration CCS on a proportion of their capacity, and Government is currently consulting on the draft National Policy Statements, which state that new coal plant must demonstrate at least 300MW (net) CCS. This does not, however, provide for an operating regime or provide any certainty on emissions.

188. The targeted EPS would be set as an annual limit on the amount of CO_2 new coal-fired power stations would be allowed to emit. The Government is consulting on two options:

- an EPS equivalent to 600g/kWh, which would be expressed as an annual limit of CO2 calculated based on plant operating at baseload;
- An EPS equivalent to 450g/kWh, again expressed as an annual limit based on plant operating at baseload.

189. Under the second option (450g/kWh), Government would look to give exemptions for plant forming part of the UK's CCS Demonstration Programme or benefiting from European funding for commercial-scale CCS, with the purpose of allowing demonstration of the full range of approaches to CCS across.

190. Both options, as an annual limit, would allow for plant to reduce their running hours in order to reduce annual emissions. This will allow for times when the CCS chain is not available, considered an important flexibility whilst CCS is a demonstration-stage technology.

191. However, a coal plant operating without CCS would suffer from increased carbon prices without the additional revenues from generation. Given the high capital costs involved in installing CCS (a condition of consent), it is unlikely operators would choose to generate without capturing and storing CO_2, except in limited periods of peak demand or when the CCS components are non-operational and electricity price sufficient to warrant paying the carbon price.

192. As part of the consultation, we are also asking for views on zero-rating or otherwise differentiating biomass for the purposed of the EPS, providing a further abatement option for generators.

193. A review policy is also proposed, as part of the decarbonisation reports required under s5 of the Energy Act 2010. This would be linked to the status of CCS technology, and assess the role of an EPS in driving further use of CCS.

194. We are not proposing an EPS which would apply to existing plant. Given the other mechanisms being considered, existing coal plant are likely to either close by 2016 under the Large Combustion Plant Directive (c.8GW), opt-out of the Industrial Emissions Directive, thereby closing by the end of 2023, or operate past 2023 on a very limited basis. The Government is, however, consulting on applying the EPS to existing plant that undergo a significant upgrade or life extension, and looking for views on what would constitute such a scenario.

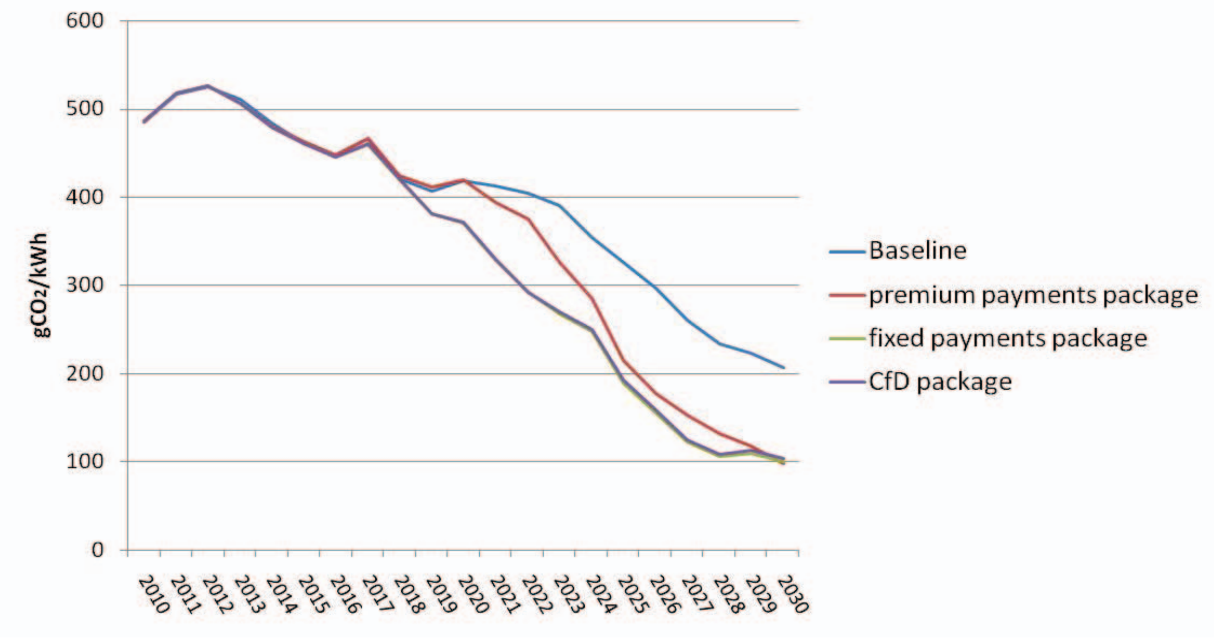
195. The Government is also proposing to apply the principle of 'grandfathering,' so that the EPS will apply to new plant at the point of consent and apply for the economic life of the plant.

6.3 Costs and benefits of combining the options into packages

196. This section looks at the impacts of combining the options into packages in terms of:
- Decarbonisation (6.3.1)
- Economic efficiency (6.3.2)
- Distributional impacts (6.3.4)
- Security of supply (6.3.5)

6.3.1 Decarbonisation

Figure C6 - Decarbonisation profile under packages

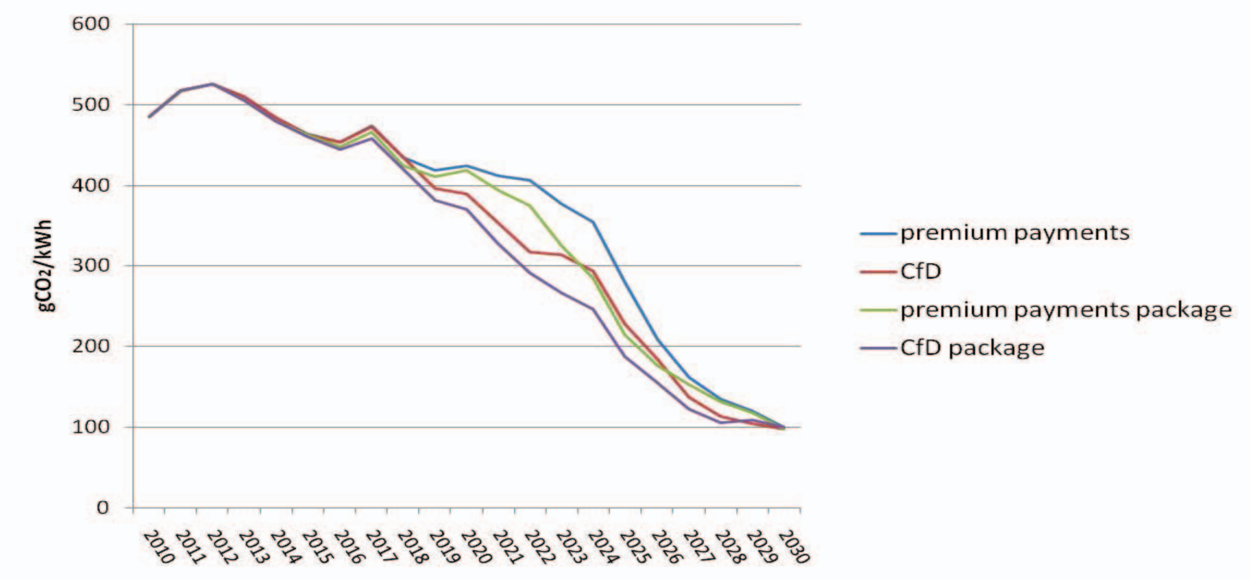


Note: the CfD and fixed payment packages achieve similar profiles

197. Figure C6 shows the rate of decarbonisation achieved in the three options compared to the baseline. Decarbonisation happens later with the premium payment package as nuclear comes on earlier with the fixed payment and CfD packages (see table B1). This is because of the lower financing costs in a fixed payment or CfD package reducing the overall costs of nuclear when compared to the premium payment package. All the packages achieve 100gCO_2/kWh by 2030.

198. Figure C7 shows the how the premium payments package and the CfD package compare to the decarbonisation mechanism when used on its own. This suggests that the packages reduce emissions earlier than when the options are used on their own. This is largely due to coal to gas switching that happens in the early 2020s due to the higher carbon price with carbon price support. It is also due to CCS running at high load factors than it would otherwise.

Figure C7 - Decarbonisation profiles for packages compared to decarbonisation options in isolation (note fixed payments are not shown as they are similar to CfD)



CPS

199. Table C11 shows that, as with the decarbonisation options when used in isolation, the premium payment packages see nuclear coming on later (2023) than the fixed payment and CfD packages (2019). The key difference in these packages is that the amount of new CCS capacity under the premium payments option is lower than under the fixed payments and CfD packages; when the payments are used in isolation premium payments lead to a similar level of CCS as fixed payments and CfD.

200. This effect is due to the introduction of carbon price support; more nuclear comes on with carbon price support when combined with premium payments as it is harder to target the support to CCS; with CPS, low-carbon generation obtains a higher proportion of their revenue from the wholesale electricity price than from the premium payment. Again it must be noted here, as in section 5 above, that CCS is not the least cost technology. On current levelised cost estimates, deploying more nuclear would have been more cost effective. With CPS, the ability to target specific technology outcomes is reduced. This is only a disadvantage where particular technology outcomes are sought.

Table C11 - New build technology profiles under each option (note that this output from the modelling should be treated as indicative)

Option	**Base**	**Premium Payments** Targeted CM CPS + EPS	**Fixed Payments** Targeted CM CPS + EPS	**CfD** Targeted CM CPS + EPS
Year of first new nuclear	2027	2023	2019	2019
New nuclear capacity (GW by 2030)	6.4	12.8	9.6	9.6
New CCS capacity (GW by 2030)	0	2.0	7.0	7.0
Retrofit of CCS demos (GW by 2030)	0	2.2	2.2	2.2

Capacity mechanism

201. Carbon emissions would only be different with a capacity mechanism if there is plant that receives payment through the capacity mechanisms that is required to run, when there would otherwise have been a supply interruption. The modelling implies that without a capacity mechanism there would be an average level of expected energy unserved (EEU) of around 3GWh per year in the 2020s. EEU up to 2020 is not significant. With a capacity mechanism EEU is expected to be zero. If it is assumed that this EEU is met by gas generation, the carbon emissions from this gas generation can be considered as additional. To put these emissions into context, the amount of electricity generated from gas CCGT in the 2020s is around 115TWh on average. Therefore the emissions associated with this back-up generation would be less than 0.003% of the total emissions from CCGT in any one year. Is it important to note that even if there were a supply interruption, emissions would not necessarily be lower as they would be offset by the emissions associated with back-up systems that may run in the event of an interruption.

6.3.2 Economic efficiency

202. Table C12 shows how net welfare changes when the options are combined relative to the baseline. Premium payments have a slightly more favourable NPV though the difference is not significant.

Table C12 - Change in net welfare relative to baseline, NPV 2010-2030, £m (2009 real)[99]

	Premium Payments Targeted CM CPS + EPS	**Fixed Payments** Targeted CM CPS + EPS	**CfD** Targeted CM CPS + EPS
Carbon costs	8,640	11,780	11,520
Generation costs	3,300	7,710	7,660
Capital costs	-15,260	-24,240	-23,970
Change in Net Welfare	**-3,130**	**-4,570**	**-4,620**

203. As above the different packages achieve different decarbonisation profiles to 2030 – the overall outcome is the same. The amount of more expensive CCS is also higher in the fixed payment and CfD packages than the premium package. This means that in terms of decarbonisation, the options are not directly comparable. Redpoint estimate that if the financing costs in the premium payment package were applied to the same decarbonisation and technology profile achieved in the CfD or fixed payment packages, overall the package would be approximately £3.3bn more costly (ie the NPV would be around -£7.9bn).

204. Combining CPS with the packages leads to an improvement in the NPV for the premium payments package when compared to premium payments used in isolation. This is because CPS provides additional certainty to investors about the revenues they will receive from the wholesale electricity price and therefore reduces their financing costs. This is in addition to the certainty (and consequential reduction in cost of capital) that premium payments provides. This effect is relatively small; this is illustrated by the fact that with exactly the same decarbonisation and technology profiles, premium payments are £4bn[100] more expensive that fixed payments and CfD, when CPS is added in it is £3.3bn more expensive (as above).

[99] A positive number shows a benefit to society, a negative number a cost.
[100] NPV 2010-2030, £m (2009 real)

6.3.3 Distributional impacts

205. This analysis considers the distributional impacts of the options, in terms of both consumers and producers but also between different types of electricity consumer.

Consumer and producer surplus

206. Table C13 shows how consumer and producer surplus changes in the packages compared to the baseline. This suggests that consumer surplus is lower in all the packages when compared to the baseline, though there is less impact on consumers under CfD. There is a transfer from consumers to producers in all options.

207. As described above, the CfD and fixed payments packages both bring on more CCS than the premium payment package and the decarbonisation happens slightly earlier. If the decarbonisation profile and the technology mixes were the same under all options, the reduction in consumer surplus under the CfD and fixed payment options would be smaller.

Table C13 - consumer and producer surplus NPV 2010-2030, £m (2009 real) [101]

		Premium Payments Targeted CM CPS + EPS	**Fixed Payments** Targeted CM CPS + EPS	**CfD** Targeted CM CPS + EPS
Consumer Surplus	Wholesale price	-14,730	-14,170	-16,150
	Low-carbon payments	1,330	160	7,410
	Capacity payments	-1,180	-1,130	-1,170
	Change in Consumer Surplus[102]	**-14,380**	**-14,950**	**-9,730**
Producer Surplus	Wholesale price	14,730	14,170	16,150
	Low-carbon support	-1,370	-70	-7,370
	Capacity payments	1,180	1,130	1,170
	Producer costs	-14,207	-14,650	-14,737
	Change in Producer Surplus	**329**	**576**	**-4,790**

208. CPS increases the wholesale price of electricity relative to the decarbonisation options when they are used in isolation. In the premium payment package, payments can be reduced as generators are receiving more through the electricity price. Premium payments when combined with CPS also reduces the likelihood of producers earning more than an economic return on their investment, which reduces costs to consumers.

209. Low-carbon payments in the CfD and fixed payments packages would be the same despite the addition of CPS, though there are benefits of combining CfD and CPS, as discussed in section 6.2.

Consumer bills

210. Table C14 shows the estimated impact of the reform packages on average electricity bills in the period to 2030, compared against an estimated baseline. This suggests that, of all the reform packages, the CfD package has the lowest average costs for consumers over the period, though the difference between the packages is small.

211. However as noted above, the CfD and fixed payments packages both bring on more CCS than the premium payment package and the decarbonisation happens slightly earlier. If the decarbonisation profile and the technology mixes were the same under all options, the

[101] A positive number shows a benefit to consumer (or producers), a negative number a cost.
[102] For simplicity expected energy unserved, change in demand side response, change in CCL and change in VAT are not shown as these are relatively small.

costs to consumers under the CfD and fixed payment options would be lower. This is demonstrated in the analysis of the decarbonisation mechanisms in isolation where the technology mix is similar; this suggests that costs to consumers in the CfD and fixed payment packages are 2% lower on average than the premium payment package.

212. As above, it is also important to note that wholesale prices, and therefore costs to consumers, can be significantly affected by low capacity margins when less efficient, higher-cost plant has to be used to balance the system.

Table C14 – Impact of packages on bills for both industrial and domestic customers

	Baseline average	**Premium Payments** Targeted CM CPS + EPS	**Fixed Payments** Targeted CM CPS + EPS	**CfD** Targeted CM CPS + EPS
Domestic (£)				
2010	£493	0%	0%	0%
2011-2015	£477	1%	1%	1%
2016-2020	£497	3%	3%	2%
2021-2025	£559	5%	7%	6%
2026-2030	£682	-1%	-3%	-4%
Average 2010-2030	£551	1.7%	1.6%	0.9%
Non-domestic (£000)				
2010	£918	0%	0%	0%
2011-2015	£948	1%	1%	1%
2016-2020	£1,152	4%	4%	3%
2021-2025	£1,401	6%	8%	7%
2026-2030	£1,564	-1%	-4%	-5%
Average 2010-2030	£1,250	2.2%	2.2%	1.3%

Impacts across different types of electricity consumer

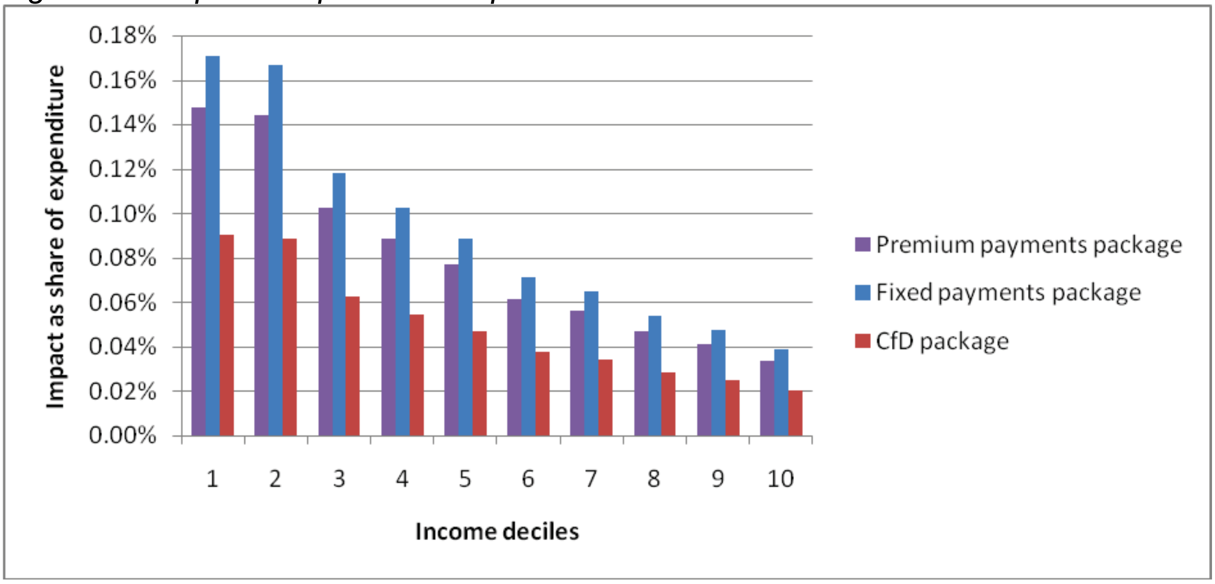
213. Increases in average domestic electricity bills can have disproportional impacts on consumers on low incomes. Poorer households, although facing a lower absolute increase in their electricity bill due to lower levels of consumption, will expend a larger proportion of their expenditure on electricity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

214. Distributional analysis provides insights into the affordability of the reform options for different households by looking at the increase in the electricity bill as a percentage of total household expenditure, when compared to the baseline. This analysis suggests that the highest impact is on households in the lowest income deciles in all of the packages. It should be noted that the same level of renewables is achieved in the baseline in 2020 as under the packages, therefore the overall impact of the packages compared to the baseline are relatively small and largely driven by the impacts of carbon price support.

By income group

215. Comparing the options suggests that the impact as share of expenditure is highest in the fixed payment package for all income groups (see figure C8). It is estimated that households in the bottom decile would spend an extra 0.17% of its expenditure on electricity compared with the baseline under this option. The impacts are lowest under the CfD package across all income groups; households in the lowest decile would spend an extra 0.15% of their expenditure on electricity, whilst households in the top decile is estimated to spend an extra 0.09%.

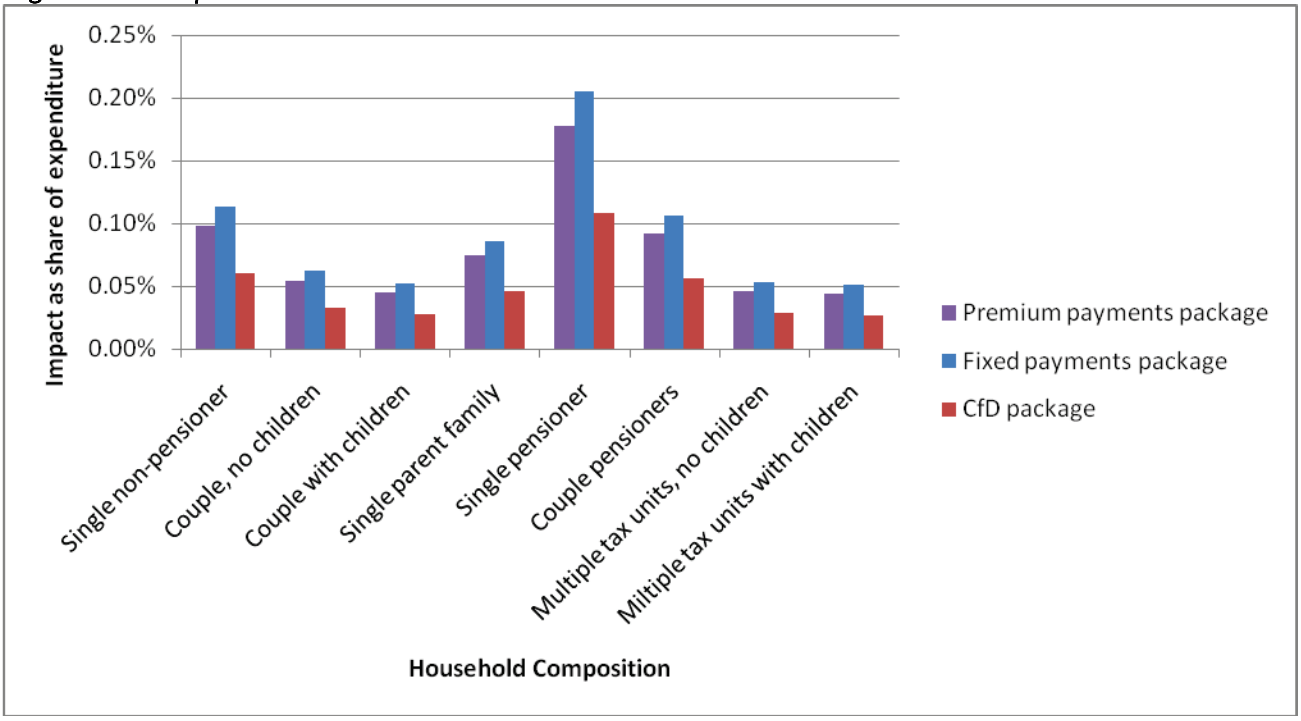
Figure C8: Impact of options on expenditure across income deciles in 2020[103]



By household composition

216. The bills impact in 2020 across different household compositions are shown in figure B9 below. The impact in terms of share of expenditure spent on electricity is greatest for single pensioners who would spend an extra 0.18 per cent of their expenditure on electricity in the premium payment package, 0.20 per cent in the fixed payments package and 0.11 per cent in the CfD package.

Figure C9: Impact on bills in 2020 across households



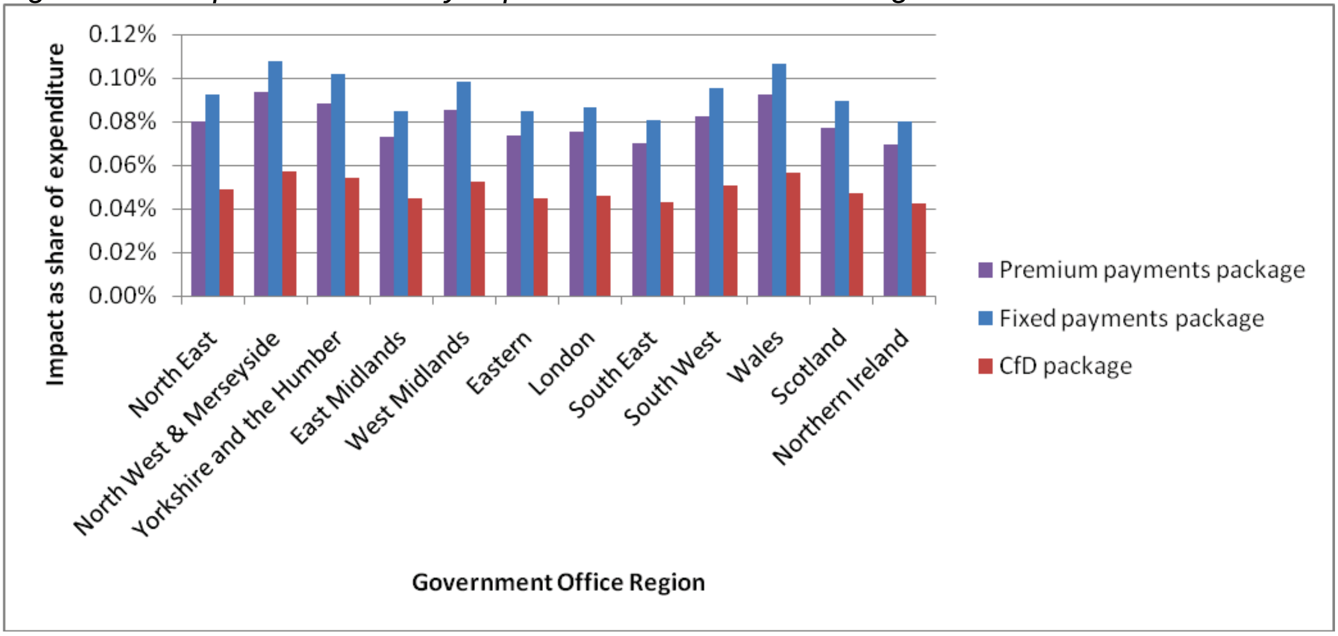
By region

217. The impact in terms of share of expenditure spent on electricity in 2020, also varies across regions. The greatest bills impact would occur in Wales and North West & Merseyside where households would spend an extra 0.09% of their expenditure on electricity in the

103 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).

premium payment option, 0.11% in the fixed payments option and 0.06% in the CfD package.

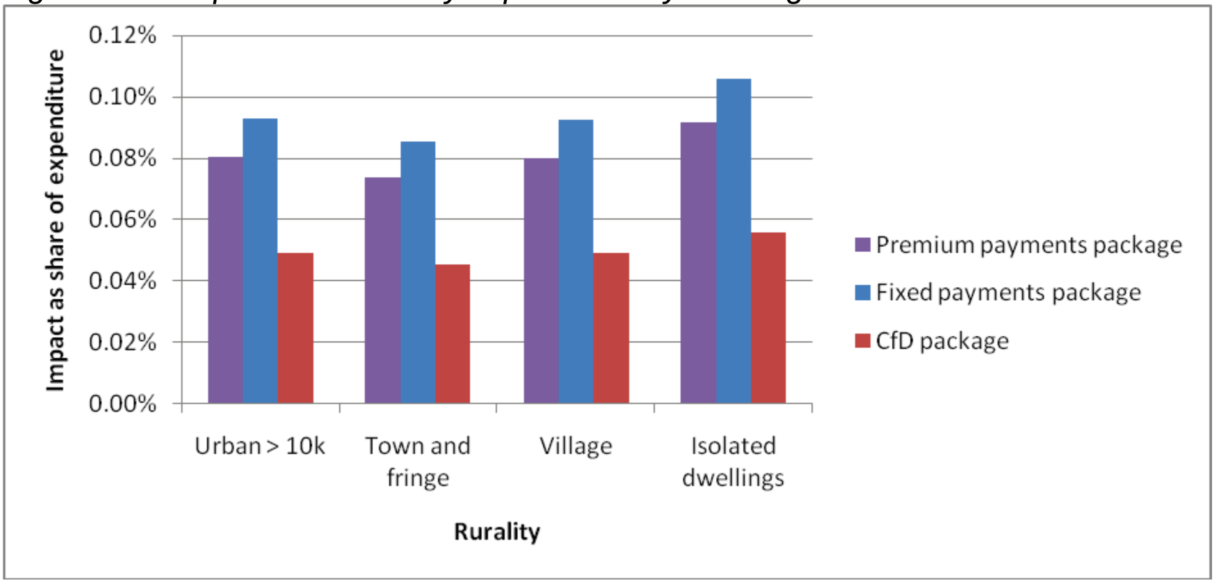
Figure C10: Impact on electricity expenditure in 2020 across regions



By location type

218. The impact of electricity bills as a share of expenditure categorised by type of location for each option in 2020 is presented in figure C11. The greatest impact would occur in isolated dwellings where households would spend 0.09% of expenditure on electricity in the premium payment package, 0.11% in the fixed payments package and 0.06% in the CfD package.

Figure C11: Impact on electricity expenditure by dwelling



6.3.4 Security of supply

219. The existence of the targeted capacity mechanisms means that capacity margins are maintained in all of the reform packages, therefore the risks to security of supply are the same in all of the packages.

7.0 Risks

220. This section considers a range of risks and the performance of the reform options against these risks, including:

- Risks of regulatory failure (7.1)
- Robustness under different fossil fuel scenarios (7.2)
- Reduced investor certainty in the carbon price support mechanism (7.3)
- Potential for market manipulation (7.4)
- Robustness under a higher electricity demand scenario (7.5)

7.1 Regulatory failure

Price

221. Fixed payments, premium payments and CfD all have the potential for excessive rents if the incentives are set poorly. The potential for the incentives being set at the wrong level is highest in options that receive the greater part of their revenues through these incentives (ie CfD and fixed payments). The way that these incentives are set (eg by auction or by government) will affect the likelihood that incentives are set efficiently. Conversely, they also have the potential for incentives to be set too low, leading to insufficient decarbonisation.

222. Redpoint have estimated the impact on consumer surplus[104] if the incentives for fixed payments, CfDs and premium payments, were set £5/MWh higher than they needed to be. To put this into context the levelised costs of onshore wind are around £80/MWh[66]. This analysis showed that consumer surplus for the period between 2010 to 2030 would be £4bn lower. This is the same for premium payments and fixed payments despite premium payments only covering part of the total costs. The reasoning behind this is that government would have to make an assessment of the total levelised costs in either case.

223. In the case of premium payments, if payments are set by government an assessment of the expected future electricity price would also need to be made.

Quantity

224. As previously mentioned, fixed payments transfer offtake risk from industry to government and ultimately the consumer. Therefore if government overestimated the amount of low-carbon generation required, the costs of this will fall on the consumer if the low-carbon plant does not run, and/or on generation operating outside of the fixed payment system if this generation displaces other generation (resulting in stranded assets). These risks would also be present if an auction-based system were used to determine the support level for low-carbon technologies (regardless of type of feed-in tariff).

225. None of the other options remove offtake risk. However the impacts of the incentives on the quantity of plant on the system will be dependent on policy design.

7.2 Performance of options under different gas and carbon price scenarios

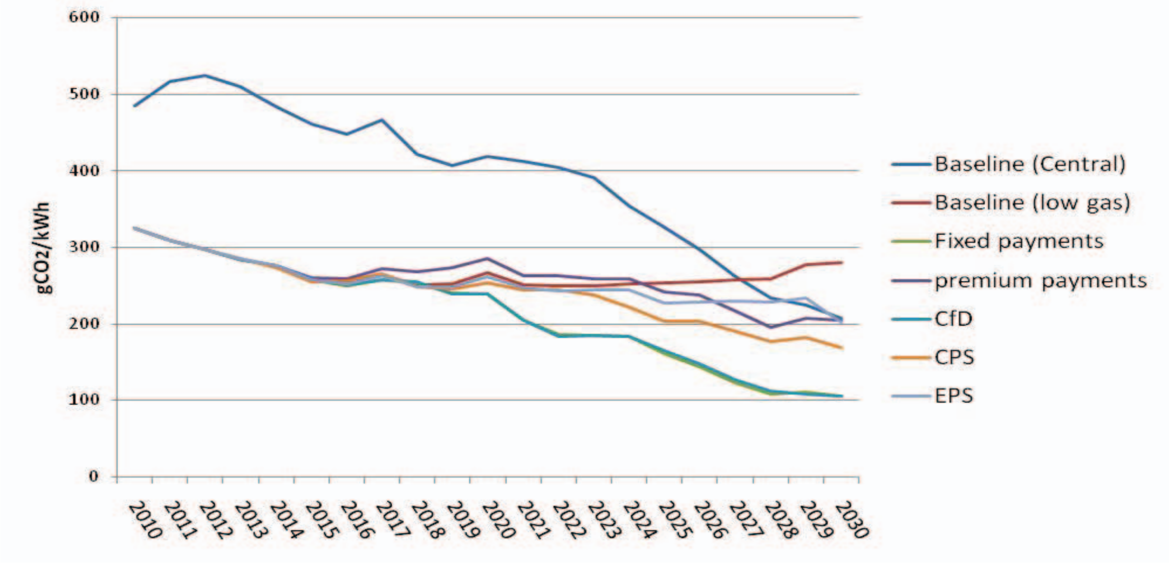
226. Each option was assessed against the three different possible future scenarios for gas and carbon prices as outlined below. The text below considers how each scenario performs in terms of decarbonisation, security of supply, efficiency and costs for consumers.

  - Low gas price (DECC low scenario at around 35p/therm from 2015 onwards)[105]
  - High gas price (DECC high scenario at around 100p/therm from 2020 onwards)

[104] Net welfare would not be affected as this would be a transfer from consumers to producers
[105] DECC, *Fossil fuel price assumptions*, June 2010

- Low carbon price (DECC low scenario)

Figure C12 – Decarbonisation in the low gas price scenario



Low gas price

227. In the low gas price scenario, the carbon intensity of the system is initially much lower than under central gas prices due to coal to gas switching (see figure B12). Under fixed payments and CfD a carbon intensity of 100gCO_2/kWh is achieved by 2030. With CfD support payments automatically increase to reflect lower revenues for low carbon generation from the wholesale electricity price. CPS, EPS and premium payments are less effective in stimulating low-carbon investment when gas prices are lower as a result of lower electricity prices. Under the premium payment scheme it would be possible for the Government to increase the level of support for new projects to replicate the incentives to invest in low-carbon under the CfD model. However, existing projects would remain on the existing (lower) levels of support, potentially offering a saving for Government, depending on the difference in gas price and number of existing CfD contracts at the point the gas price deviated from expectations.

228. It is assumed here that premium payments are not adjusted if the out turn in low-carbon generation is lower than expected. It is possible that government would respond to sustained lower gas prices by increasing the premium payments to achieve the decarbonisation required.

229. The risks to security of supply appear to increase under lower gas prices as a result of earlier closures of coal plant that are no longer profitable. These risks appear greatest under fixed payments and CfD where investment in gas CCGTs is deterred by the earlier deployment of nuclear and CCS.

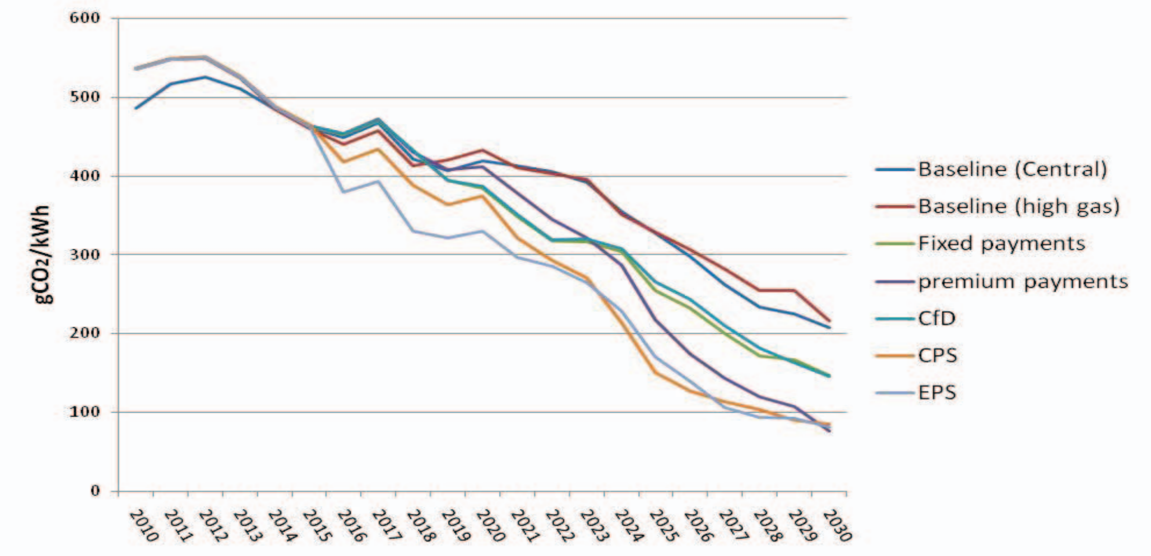
230. The impacts on net welfare of the EMR options in the different scenarios is shown in table C15. This table shows the change in net welfare when compared to the baseline in the scenario.

231. With a low gas price, net welfare appears much lower than under fixed payments and CfD than the other options since these deliver more low-carbon investment, which is considerably more expensive than the alternative (ie gas) generation under this sensitivity. Consumers are worse off under all the policy options since wholesale electricity prices are considerably higher than the baseline due to some occasions of very low de-rated capacity margins. It should be noted that the modelling assumes that a long term structural shift in the gas price does not result in a change in the carbon price. A sustained low gas price

should in principle result in an increase in the carbon price in the long term, assuming a continued downward trajectory for the EU ETS emissions cap.

High gas price

Figure C13 – Decarbonisation in the high gas price scenario



232. In the high gas price scenario, the high prices increase the carbon intensity of the system in the near term as it increases the amount of coal generation (figure C13). Despite similar levels of low-carbon investment, emissions are higher under fixed payments and CfD due to more coal-fired generation and they do not meet the 100gCO_2/kWh level in 2030. However the high gas price stimulates more low-carbon investment under CPS, EPS and premium payments leading to emissions intensity slightly below 100gCO_2/kWh by 2030.

233. It is important to note that it is assumed under this scenario that the coal price does not change from the central scenario. It is questionable how likely this is in practice given the substitutability between coal and gas for electricity generation. If the coal price also changed, emissions from coal generation would be lower and the resultant carbon intensity in fixed payments and CfD would be closer to 100gCO_2/kWh in 2030.

234. The risks to security of supply under high gas prices are not significantly different than under central gas prices.

235. Under the high gas sensitivity, net welfare is positive under fixed payments and CfD relative to the baseline, reflecting increased generation costs in the high gas price baseline but not under these policy options. Under the premium support options, CPS and EPS and premium payments, net welfare decreases since they 'over-deliver' low-carbon investment. Consumers are significantly better off under the high gas price sensitivity under fixed payments and CfD.

Low carbon price scenario

236. In the low carbon price scenario, CPS and EPS counteract the effect of a lower EUA price but 100gCO_2/kWh by 2030 is not achieved under the other policy options. With premium payments, fixed payments, and CfDs there is more unabated coal and gas burn and lower load factors for CCS plant.

237. The risks to security of supply under low carbon prices are not significantly different than under central gas prices.

238. All options show negative net welfare under the low carbon price sensitivity since they deliver more low-carbon investment relative to the baseline which is more expensive than the alternative generation. Consumers are worse off as a result, and particularly in cases where wholesale electricity prices spike due occasions of very low de-rated capacity margins, as is particularly the case under CPS.

Figure C14 – Decarbonisation in the low-carbon price scenario

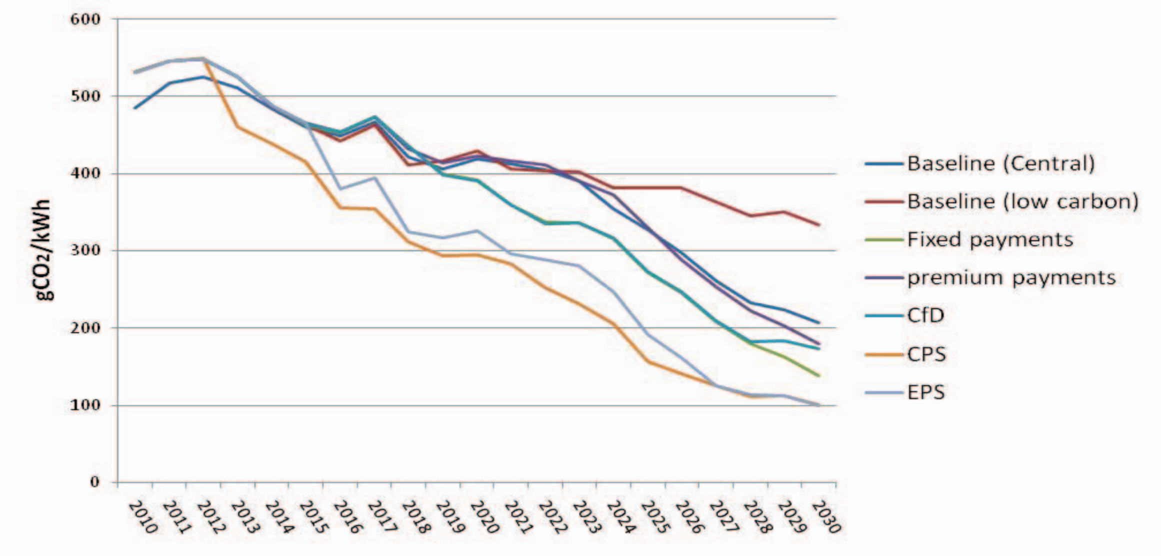


Table C15 - Change in Net Welfare in the alternative scenarios (compared to the baseline in each scenario – ie low gas, high gas and low carbon price baselines)

		CPS	EPS	Premium Payments	Fixed Payments	CfD
Low gas price						
Net Welfare	Carbon costs	5,735	2,965	2,742	11,283	11,174
	Generation costs	-516	-6,931	115	4,441	4,845
	Capital costs	-7,287	-1,656	-11,071	-35,211	-35,600
	Change	**-2,126**	**-5,668**	**-8,985**	**-19,916**	**-20,025**
High gas price						
Net Welfare	Carbon costs	14,610	15,595	10,469	7,183	6,649
	Generation costs	-5,663	-19,155	6,562	5,961	6,181
	Capital costs	-18,840	-14,257	-24,111	-12,142	-11,002
	Change	**-9,597**	**-17,508**	**-7,272**	**964**	**1,711**
Low carbon price						
Net Welfare	Carbon costs	11,575	10,112	3,801	6,245	5,837
	Generation costs	-9,860	-8,811	2,265	9,196	8,704
	Capital costs	-20,685	-22,387	-18,541	-28,084	-27,826
	Change	**-18,796**	**-20,945**	**-12,817**	**-12,704**	**-13,408**

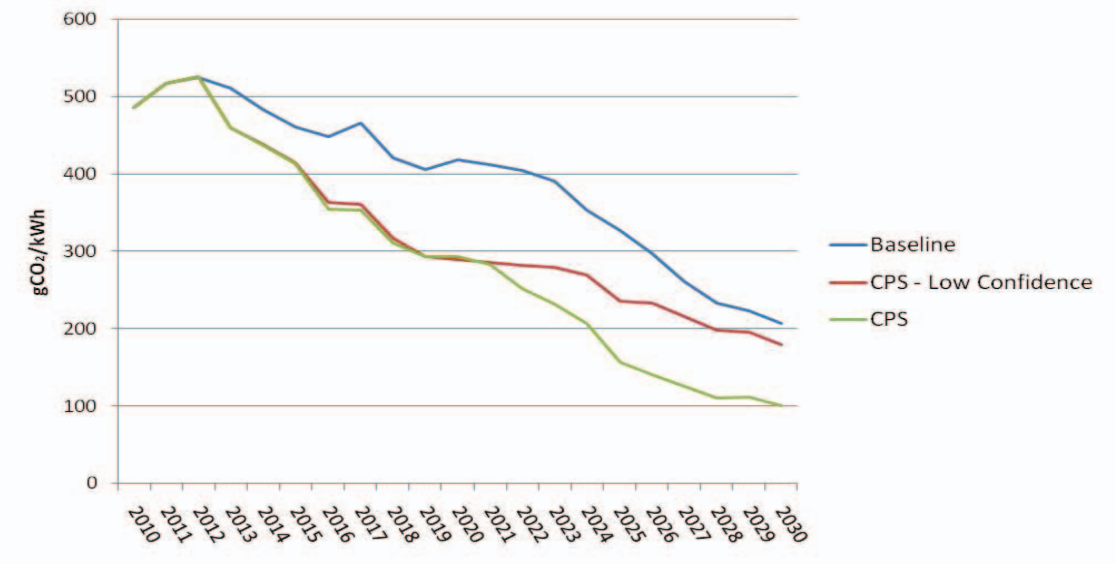
7.3 Lower certainty of carbon price support

239. The modelling tested a scenario where there is a reduced level of certainty of the CPS mechanism. Therefore instead of having perfect foresight of the CPS for five years and then flat-lining the carbon price from that point forward, it was assumed that investors have perfect foresight for five years and then assume that the carbon price drops back to that at the time the investment is made.

240. Figure C15 shows the impacts of the reduced certainty on the profile of decarbonisation. This suggests that the degree of confidence in the CPS mechanism has a very significant impact on investment in low-carbon. In this scenario, investment in low-carbon generation in the 2020s is similar to that seen in the baseline (see table B2); new nuclear plant is not built until 2027 and there is no CCS capacity other than the demonstration projects.

Investment in renewables in the 2020s is lower as it is assumed that the level of RO support is not adjusted to account for lower carbon price support certainty.

Figure C15 – Profile of decarbonisation with low confidence in CPS



7.4 Potential for market manipulation

241. Each element of the Electricity Market Reform proposals has been designed to address a specific market failure or manage a risk to the achievement of the Government's stated objectives. The measures will combine to impact the market in complex ways, some of which will be complementary while others may conflict with our goals. In complex markets with payments to specific technologies, international experience in recent decades has shown a clear tendency for companies to seek to manipulate markets to maximise profits. In this section we are seeking to identify the potential for market manipulation and any measure to mitigate the effects. We consider each measure in turn and the potential for market manipulation.

Carbon price support

242. Carbon trading in the EU has hitherto resulted in windfall gains through the free allocation of allowances, problems with verification of emissions reductions and the uncovering of some instances of fraud. Any proposed support in GB of the price of carbon emissions reductions will operate alongside the current emissions trading system (EU ETS) and will feed through to wholesale electricity prices and to prices paid by consumers. It is however unlikely that carbon price support in itself will present significant risks of market manipulation.

Emissions performance standard

243. An Emissions Performance Standard (EPS) would be intended to supplement the EU ETS and existing European emissions control legislation to ensure that new high-Carbon generation is not built. However exceptions may need to be agreed to some generation on a technology or case-by-case basis which may affect the credibility of the policy.

Low-carbon revenue support

244. The inevitable consequence of creating incentives for the achievement of renewable energy and carbon targets is the transfer of substantial sums from consumers and/or taxpayers to project developers. This occurs even if support is efficiently delivered, but inefficiencies in delivery and lobbying by developers for increased support exacerbate the

problem, leading to developers and energy suppliers earning a more than an economic return on their investments.

245. Low-carbon support is open to all existing and new market participants without discrimination, but it may turn out that a small number of companies dominate the delivery of particular technologies. This may have an adverse impact on competition within the wider market. If there is uncertainty or an increased perception of risk among potential investors, investment in new low-carbon generation may be deferred. Insufficient incentives to attract investment, or barriers to enter the market, may also have an adverse impact.

246. Lack of market liquidity, an issue currently under investigation by Ofgem, may represent a risk to the operation of low-carbon support mechanism such as CfDs. Energy suppliers may be able to distort prices in thinly traded markets to profit across their operations and also to deter new market entrants in both generation and supply.

7.5 Performance of options under a scenario with higher electricity demand

247. Current DECC scenarios see the demand for centrally generated electricity rising slightly to 2030; it assumes that demand will be about 7% higher in 2030 compared to 2010. The increase is driven by a move towards the use of electricity in the heat and transport sectors, which is offset to some extent by improvements in efficiency.

248. It is possible that this shift into electricity from the heat and transport sectors will be more marked, particularly in the 2020s, which would result in a higher level of electricity demand. To investigate the impacts of higher electricity demand, the modelling tested the packages of options (see section 6) against a higher demand scenario consistent with CCC recommendations. Under this scenario demand increases by around 9% by 2020 and then more rapidly to 2030 when it is around 30% higher than demand in 2010.

249. This analysis suggests that the indicative grid carbon intensity of 100gCO_2/kWh can be achieved with both the CfD package and premium payments package. The technology mixes in both packages are the same by 2030, with around 16GW of nuclear and 7GW of CCS. With CfD, the modelling indicates that developers would make nuclear investments 2 years earlier than with the premium payment package; therefore, the decarbonisation trajectory is slightly slower.

250. The modelling assumed that investors anticipate the increase in demand. If this were not the case, then the costs associated with the capacity mechanism would have been higher.

251. Net welfare under the CfD package is positive under this scenario, at £6.6bn (2010 to 2030 real). Under the premium payment package the NPV is around zero; that is net welfare is about the same as the baseline. If the decarbonisation and technology profiles achieved in the premium payments package were identical to the CfD package, the NPV would be £4.1bn lower, ie a positive NPV of £2.5bn. Therefore, the more investment needed to meet the Government’s decarbonisation objectives, the more significant the benefits from a reduction in the cost of capital become. Similarly, if demand were below central expectations, the difference in net welfare is expected to be smaller.

8.0 Stability and durability

252. A number of issues have been identified relating to the stability and coherence of the options. These are related to the type and quantity of plant that will come on to the system in the low-carbon transition; one scenario for the low-carbon transition is shown in figure C16.

Viability of the wholesale market price

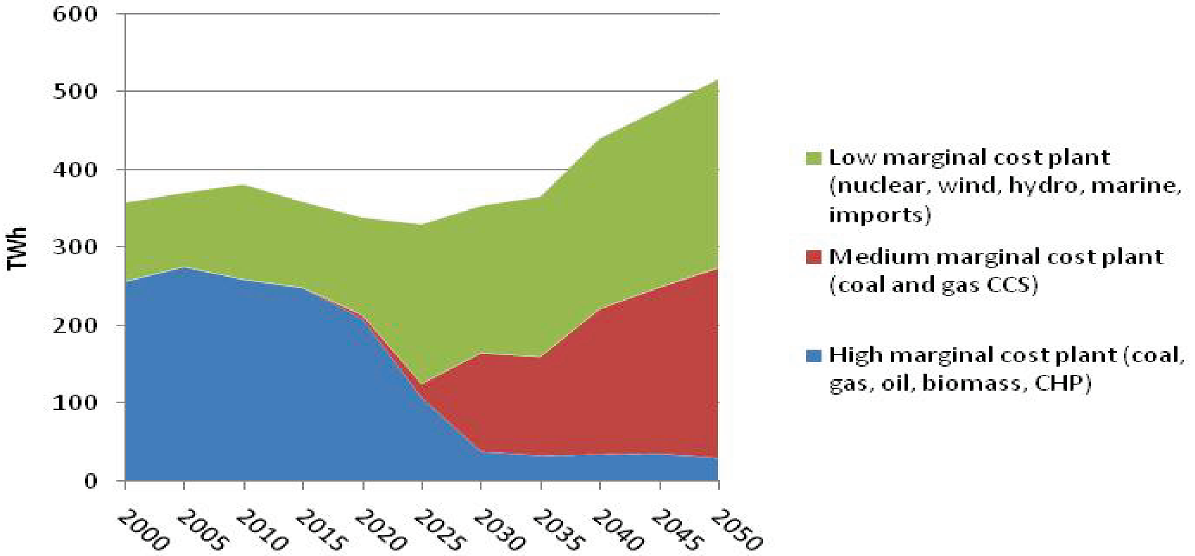
253. The options for reform will have varying impacts on the quality of the wholesale market price signal. CPS, EPS and premium payments should in principle have the lowest impact on the quality of the wholesale price signal as all electricity generated could still be sold through the wholesale electricity markets. This would though be offset by the extent to which the various options address barriers to entry and improve liquidity in the wholesale market (see section 5.5).

254. Fixed payments and CfD effectively remove a large volume of electricity from the wholesale market. There could therefore be a risk that the quality of the wholesale electricity price signals will be undermined. This would not only affect competition but it would also have implications for implementation of CfD which relies on the price signal to settle contracts. The majority of the low-carbon generation that would be covered by a fixed payment or a CfD would however not be price setting; therefore whilst it might reduce the volume of electricity traded, it may not necessarily reduce the quality of the price signal.

High proportion of low marginal cost plant

255. Whilst there are clearly many possible technology outcomes, one common characteristic is the higher proportion of low marginal cost plant after 2030. High uptake of low marginal cost plant starts to drive down the average electricity price and leads to questions about how the electricity price will be set in a largely decarbonised system; particularly whether a system based on marginal pricing is sustainable[106].

Figure C16 – Possible characteristics of the generation fleet to 2050



Source: Markal modelling for CCC 2008

256. Options where low-carbon generation is not reliant on the wholesale electricity price for revenues, including fixed payments and CfDs[107], are more robust against high penetration of low marginal cost plant than options that rely on the electricity price for revenue. There is therefore a risk that longer term investments may start to be affected by this uncertainty under a system of premium payments or with CPS alone. There would be similar risks with an EPS. Investors may start to price uncertainty into the level of premium payment they would be prepared to accept.

[106] There are scenarios where the current market arrangements could still work in a decarbonised system, such as high uptake of demand side response, but there is a high degree of uncertainty.
[107] CfDs may result in a degree exposure to electricity price risk, particularly before settlement

257. The long lead-in times and long lifetimes of low-carbon generation means uncertainty of how prices will be set in this period are not insignificant[108].

Uncertainty about the technology that will be setting the price and the related impact of the carbon price

258. In the early to mid 2020s, the carbon price is forecast to drive up the electricity price as unabated fossil fuel generation continues to set the marginal price. Modelling suggests that gas CCGT will continue to set the price for 70% of the time despite only providing 10% of the electricity[109].

259. Beyond this point, there is uncertainty about which technology will be setting the price and therefore the role that the carbon price will play in providing revenues, particularly for baseload low-carbon generation. Therefore, as above, EMR options that retain the link to the wholesale electricity price as the primary revenue raising mechanism are exposed to this effect.

9.0 Transition issues

260. We need to consider the impact that the different packages will have on investment in the shorter term, since major change to the market arrangements could result in developers delaying their investment plans. The impact of the different packages on hiatus in investment is likely to differ by technology. The impact on nuclear and CCS is likely to be marginal to small. Therefore the discussion concentrates on the impact on delays to renewable investment.

261. Under the do nothing option, i.e. keeping the current system of support for renewable generation through the Renewables Obligation (RO) in place, the risk of a delay to investment is small. The RO banding review is likely to create some hiatus as the review will involve having a 2011 consultation, a Government Response announcing the new support levels late in 2011/early 2012, State Aids approval and a reviewed RO Order by April 2012. Over this period until April 2012 there is likely to be some investment hiatus as the reviewed bands could still change. After April 2012 hiatus in the do nothing option is likely to end. Implementation of the reviewed obligation would be by 2013.

262. For ease, the discussion below uses the following stylised assumptions about the degree of investment hiatus:

- 'High risk of delay': 50% to 100% reductions in financial closes (point at which a company firmly commits to a project) – impacting on new commissioning say 2 to 3 years later than previously thought
- 'Medium risk of delay': 25% to 50%
- 'Low risk of delay': 10%.

263. The premium payment package could be implemented on the same timescale as the RO Banding review and could therefore also be implemented by 2013. This would imply a low risk of delay in renewable investment while investors learn to understand the new mechanism. Hiatus is also considered to be low as investors are already expecting a change in support levels for renewables by 2013 – coupling this with a change towards a premium payment package reduces possible delays.

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108 eg 2030 is only 10 years into the 40-year lifetime of a nuclear power plant built in 2020, which may be under development as early as 2012.

109 Redpoint modelling for CCC, 2009

264. A fixed payment or CfD package would need to be implemented on a different timescale to the RO banding review. Implementation by 2013/2014 (2014 set out in Redpoint assumptions) seems likely (although as discussed below a phased implementation for renewables could help mitigate the risk of delay to investment). This implies that support levels could be announced around 2013 (one or two years before implementation).

265. A change to a fixed payment or CfD package would therefore announce support levels one or two years after the reviewed RO bands are announced. This implies an additional one or two years of high hiatus levels for renewable investments, as some renewable investors will wait for final confirmation of bands a few months before April 2014 (assuming financial years).

266. After April 2014, there is likely to be a continued lower level of delays to investment decision, as, particularly under a CfD package, investors might choose to wait one or two years to see what CfD look like and to understand how they work. In a fixed payment package, there is likely to be a bigger impact on gas CCGT investment as these investors might decide to wait and see what a new smaller wholesale market will look like.

267. Generally, for all of the different options we would expect the likelihood that investors delay decisions to fall over time as certainty for investors rises, the longer a new system is in place. Table C16 below illustrates this.

Table C16 – Scale of potential hiatus in renewables under options

Do nothing	**Premium payment package**	**Fixed payment package**	**CfD package**
End 2010 to Summer 2011 – 'high hiatus' for large biomass Summer 2011 to late 2011 – 'medium hiatus' for all renewables	As do nothing plus: 2012 – 'low hiatus' while investors try to understand new mechanism	As do nothing plus: 2012 – 'high hiatus' 2013 – 'medium hiatus' 2014 – 'low hiatus'	As do nothing plus: 2012 – 'high hiatus' 2013 – 'medium hiatus' 2014 – 'medium hiatus' 2015 – 'low hiatus'

268. There are options to mitigate the hiatus:

- Allow a transition period for renewables, stating clearly now that generators taking investment decisions prior to introduction of CfDs will be able to accredit under the RO;
- Run the RO and CfD in tandem for a set period, giving generators a choice.
- Alongside this, to announce the process for setting tariff levels as soon as possible, and set the levels as quickly as possible.

269. Allowing a transition period would give large scale generators the certainty they need to make their investments over the next few years until support levels are decided. The preferred option is to allow projects to be eligible for the RO up to 31 March 2017, but in a manner that allows projects to sign up for a CfD from summer 2013 – so that large scale projects with a long construction time, can be eligible for a CfD once construction is complete.

270. This preferred option should provide a smooth transition between the RO and CfD, giving as much regulatory certainty as possible over the transitional period. Delaying the introduction of CfD for renewables will reduce the relative cost savings of the overall package, but it would reduce the risk of missing the renewable energy target.

271. For projects that commission between 2013 and 2017, they could either be kept automatically in the RO or be offered the choice of taking up the RO or the CFD, as per

the two options above. The latter option would increase the administration costs over this period.

272. The main cost of a transition period for renewables would be to delay the benefits of moving to the CfD system outlined above (i.e. increased revenue certainty leading to a reduced cost of capital and resource cost savings).

273. The other main issue with respect to transition from the RO to CfD is what to do with the existing generation under the RO after the introduction of the CfD. The two main options would be to retain all existing in the RO or to transfer it all to a the CfD system.

274. The first option would have the benefit of simpler grandfathering arrangements. With the second option, there may be the risk of rents on the one hand, or undermining investor confidence on the other, as it will be difficult to set the CfD strike prices at an equivalent rate to RO support, as defining the equivalent rate will be difficult. However, the second option would be administratively lower cost in the long run, as only one support system would be maintained rather than two.

10.0 Macroeconomic impacts

275. The aim of this section is to compare the relevant merits of the options we are consulting on in terms of the wider macroeconomic impacts not quantified in the cost benefit analysis above. It should be recognised that it is not always clear whether the impacts are from different EMR options or the impacts of meeting carbon and renewables targets more generally.

276. The level of investment in renewable and low-carbon technologies will need to increase in the coming decade to meet renewable energy and decarbonisation targets. Even though this could come at the expense of investment in non low-carbon plant, the overall level of investment is likely to increase due to the higher costs of renewable and low-carbon technologies than conventional fossil fuel generation plant. The scaling up of investment in the electricity sector could create large business opportunities, although the share of this increase directly attributable to EMR is uncertain, and it is not clear whether these growth opportunities are additional or just displace economic activity in different sectors.

277. EMR could also make the UK relatively more attractive and possibly attract investment from large international utilities and other (institutional investors that would have otherwise chosen to invest elsewhere. Nevertheless, the scale of investment needed could potentially crowd out investment in other areas of the economy. If EMR policies enabled greater recycling of capital (from e.g. infrastructure funds or banks) or improve the ability to introduce co-investors (such as equipment suppliers and financial investors) that would have otherwise invested elsewhere in the economy, these investments would be drawing resources to the electricity market that may have been invested elsewhere.

278. EMR options that allow a diverse electricity generation mix to be incentivised may have macroeconomic benefits for society as a whole. Furthermore, increasing security of supply from introducing a capacity mechanism will benefit society by reducing unserved energy. This benefit has been estimated to be around £400million to over £1billion for the period 2010 to 2030 (PV, 2009 real) depending on the assumption made on the Value of Lost Load[110] (see part B).

279. Options that will result in relatively high electricity prices in the near to medium term could reduce the competitiveness of industry based in the UK. However, intensive energy users

[110] Value of Lost Load (VOLL) is the cost society places on electricity supply disruption. Figures above assume £10,000/MWh and £30,000/MWh VOLL.

could benefit from more stable wholesale prices (from fixed payments and CfD) as this could reduce the energy price risk of their operations and future investments. This reduction in risk could therefore result in energy intensive business projects benefiting from reduced costs of capital, however, businesses will already have hedging strategies in place to eliminate this risk. Reducing volatility could reduce the cost of these hedging strategies.

11.0 Impact on business

280. The text below explains the foreseen costs and benefits to business associated with each of the four components in the packages for consultation. It should be noted that calculation of cost and benefits are indicative at this stage, as estimates of impacts will be more robust once detailed implementation of policies are worked out post consultation. Our indicative analysis at this stage suggests that overall, the benefits to business from the policy packages we consult on would outweigh the cost.

281. Costs to business from the mechanisms, when used in combination with a targeted capacity payment and carbon price support, could arise from higher electricity bills in the near and medium term, although bills are estimated to decrease under all options in the late 2020s (see table C14 for details on bills impact).

282. The proposed EPS will only apply to *new* plant, not to existing projects, and therefore not have a cost to existing business.

283. For existing plant, the Government envisages that the cost to business from the introduction of an EPS would not be significant. The proposed EPS will only apply to *new* plant, not to exiting projects, and generators are already required to report verified emissions as part of the EU Emissions Trading Scheme (EU ETS) meaning that we do not envisage any additional reporting requirements for new projects. There will most likely be no cost of compliance over and above requirements to demonstrate CCS already outlined in the draft National Policy Statements. However, calculation of specific administrative costs are better left to detailed implementation, as much will depend on how the EPS is introduced and administered.

284. CPS is an HM Treasury policy and an environmental tax out of scope of ”one-in, one-out”.

285. The decarbonisation mechanisms (Premium Payment/Fixed Payment/CfD) consulted on would be relevant for new plant only, and therefore not have a cost to existing business. Therefore, investment in existing projects under the RO are protected. For new plant they would replace the existing Renewables Obligation.

286. The removal of the RO legislation would imply savings for business from no longer having to dedicate productive business resources to meet the requirements of the legislation. The allocation of business resources to meet the requirements of the new legislation would depend on how the decarbonisation mechanisms would be implemented.

287. The Government believes that the largest administrative costs are believed to occur to the central agency tasked with administrating payments under all the mechanisms, with the CfD likely to lead to relatively higher administrative costs compared to the other two options due to added complexity and novelty.

288. Benefits to business from the introduction of any of the mechanisms is to transfer revenue risk away from low-carbon generation, lowering the energy companies’ cost of capital. Moving away from an RO to either of the three options would remove uncertainty surrounding the level of “top-up” support to the wholesale price for renewable generators

currently covered by the RO, and introduce additional and secure revenue streams for a larger portion of generators.

12.0 Devolution issues

289. Changing the support mechanism for renewables away from the Renewables Obligation (RO) could have complex implementation issues because the RO is devolved to Scotland and Northern Ireland (NI). In 2009, almost half of UK renewable electricity installed capacity was situated in Scotland, and c.4% was in Northern Ireland[111].

290. For Scotland, the RO is executively devolved under powers contained in the Electricity Act 1989. This means that the Scottish Executive is able to exercise those powers to make regulations for the RO in Scotland, but the powers themselves are determined by Westminster. The powers give the Scottish Executive a great deal of freedom in how they design the RO for Scotland. For example, the Scottish Executive can set their own banding levels. The banding levels have been generally the same as those set in England and Wales, apart from for wave and tidal for which they give 5 and 3 Renewable Obligation Certificates (ROCs). Wave and tidal get 2 ROCs in England and Wales.

291. As renewable energy policy is fully devolved in Northern Ireland (NI), NI have their own primary legislation and set their own banding levels. The banding levels are generally the same as those in England and Wales with the exception of micro and small generation, as NI has not introduced small-scale feed-in tariffs. As all NI generation goes into the Single Electricity Market with the Republic of Ireland, any new support mechanism would have to be specifically adjusted for the NI market to take account of this.

292. In addition, the new support mechanisms consulted on include support for all low-carbon generation which would include, but is not limited to, Carbon Capture and Storage (CCS) and nuclear generation as well as renewable electricity.

293. Scotland in particular has an abundance of renewable electricity resources, and will contribute significantly to UK renewable electricity deployment in the future. Therefore, the territorial scope of the new mechanism would affect how much generation it includes.

294. If Scotland do not enter the new mechanism, but continue with their current RO, or have a different mechanism, this could have negative impacts on investment because the UK regulatory environment would be more complex for investors to understand. 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.

13.0 Availability of finance and the impact of the options

13.1 Availability of finance

295. This section considers whether there could be a financing gap in the 2010s with consequent impacts on renewable energy and carbon targets. This is done by assessing the scale of capital expenditure (capex) that needs to be made by energy companies in generation and other mandatory and non-mandatory investments up to 2020; this demand for capital is then compared with broad estimates of the supply of capital from the Big 6 utilities' balance sheets and other sources of finance, such as independent generators and project finance.

The demand for capital

[111] Source: Energy Trends, September 2010

296. Capital investments will be needed in several segments of the energy market; in new electricity generation assets, supply and retail, and in gas and electricity networks.

Generation Capex

297. Redpoint modelling has shown that around 30GW of new generation capacity could be needed by 2020 to meet the renewable energy target, and to maintain progress on a trajectory to meet 2050 carbon reduction targets[112]. The 30GW of new investment by 2020 consists largely of renewable build, predominantly onshore wind and offshore wind. In addition to this, the modelling indicates that other renewables will be built, along with new CCGT capacities and the CCS demonstration project. Using recent expected capital costs for these technologies[113], this implies an estimated annual investments capital expenditure of around £7bn p.a.[114] in the next decade, or a total estimated demand for capital of c. £70-75bn by 2020. Costs associated with other build rates will differ.

298. This estimate of demand for capital is in the same range as estimates from other sources. For example, modelling done for Ofgem's Project Discovery[115] found that around £75-80bn of capital expenditure would be needed by 2020 to deliver around 30GW of new electricity generation capacity. Similarly, the CBI's estimated[116] £100-130bn of investment needed in new electricity generation capacity to 2030, implying annual investments of around £5-6bn a year over this time period.

299. Between 2020 and 2030, the Redpoint modelled build rates indicates that an additional 30GW new generation capacity will be required from a mixture of generation types with an implied demand for capital of around £50bn (in 2009 prices) between 2020 and 2030, or about £5bn p.a.[117]

Transmission & Distribution Network Capex

300. Investments needed in the electricity networks will depend on the generation mix and the geographical location of these plants. Ofgem's Project Discovery estimate that around £40bn of investment will be needed in electricity and gas transmission and distribution up to 2020, with the majority of investments needed in electricity. In addition to this, Ofgem estimates that up to around £2bn in total could be required in LNG terminals and gas storage, as well as c£2bn in electricity interconnectors and fitting of SCR.

Supply and retail

301. Vertically integrated energy companies could also face additional financing requirements in supply and retail which could impact the company's ability to raise the capital required for new generation build.

302. Excluding financing costs, the roll-out of smart meters to households and SMEs could cost an estimated £1.6bn in capital expenditures to 2020 to be shared between energy suppliers. Electricity suppliers also collectively face approximately £0.6bn on average of annual costs in CERT and the CERT extension between 2010 and 2012 (£1.9bn to 2020). Additionally an extension to the Supplier Obligation could cost electricity suppliers around

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112 New build requirements vary between the modelled scenarios
113 Capital costs in pre-development and construction. Source: Mott McDonald (2010) "UK Electricity Generation Costs Update"
114 Around £6-7bn p.a. from 2010 up to and including 2020
115 Ofgem, *Project Discovery - Options for delivering secure and sustainable energy supplies*, 3 February 2010
116 CBI (2001) "Decision time, Driving UK towards a sustainable energy future"
117 These are costs only associated with new build that come online by 2030, there will be capital investment needed in the period up to 2030 related to capacities coming online after 2030 that are not captured in this figure.

£6bn from 2013 to 2020. All these costs could be an additional burden on the energy companies. However the cost associated with the Supplier Obligation and the CERT (and extension) are not capital expenditures but could be a permanent cost of sales financed by revenues, and it is at the suppliers' discretion whether they pass on these costs to customers' bills[118].

303. Further to these investments, energy companies will be affected by the potential costs related to the Green Deal Finance programme. The Green Deal will establish a legal mechanism allowing payments towards the costs of energy efficiency measures to be attached to the energy meter at a property. Payments will be collected by energy suppliers and passed to Green Deal providers. The cost impact on energy suppliers will depend on the set-up of the Green Deal Finance arrangements: the amount of default risk taken on by energy suppliers, administration costs and, if energy suppliers chose to be Green Deal providers, how much capital – if any - they commit.

The financing challenge

304. Of the estimated £110-120bn of capex investment needed in new electricity generation, supply & retail and energy networks to 2020, we believe that where utilities have network businesses, they may prioritise network spend. This is because:

- the revenue stream for networks is regulated through a RAB, which ensures regular, low volatility cash flows demanded by utility shareholders and lenders; and
- the utilities' license conditions require them to deliver their regulatory commitments.

305. As a result of this, a financing challenge is most likely to arise in the generation sector, rather than in network investment, or supply and retail. The supply of capital in the generation sector are analysed in the section below.

The supply of capital

306. Data[119] on energy companies' capital investments in the UK on electricity generation alone show that they invested £3-4bn in the UK in 2007 and 2008[120], with around £4.5bn invested in 2009 (table C17) . Data for 2010 shows that around £2bn has been invested in Q1 and Q2 so far this year. Industry estimates of the likely supply of capital in the future vary. Some estimates have indicated that utilities could support around £4bn p.a. of balance sheet financing, whilst for example Ernst&Young[121] estimate that c.£3-5bn p.a. of funding could be available from current funding sources up to 2025 for investment in the low-carbon sector in the UK, of which up to c.£3bn p.a. could be from utilities.

Table C17 – Historical investment in electricity generation assets

Year	Investment (£bn)
2007	2.7
2008	3.8
2009	4.5
2010 (Q1+Q2)	2.1

Source: ONS

Big 6 utilities' balance sheets

307. PwC analysis estimated that the Big 6 and National Grid combined had annual capital expenditure programmes in the UK of around £8bn and £9bn in 2008 and 2009

118 DECC analysis
119 Source: ONS, October 2010
120 This figure includes capex on electricity "new building work" and "plant and machinery".
121 Ernst&Young, 2010, "Capitalising the Green Investment Bank, Key issues and next steps"

respectively[122]. However, they have not broken this down into generation and non-generation investment.

308. Many uncertain factors are at play in estimating a likely maximal spend by the utilities on new generation capex. Firstly, as the Big 6 not only invest in the UK, their future share of investment in the UK as opposed to in other markets is uncertain. Unless the existing investor base diverts a greater share of their global capex to the UK from European and other markets, a spend of c.£3-4bn per year. Utility investment decisions will also be influenced by a number of other factors such as their global capex programme plans and the relative attractiveness of low-carbon investment within their corporate portfolios.

Independent generators

309. Additional funds could come from independent generators (i.e. non-big 6 players, including both British and international energy companies) investing in the UK. These independents include very large organisations such as Dong Energy, Vattenfall, Statkraft and GdF. Based on current generation plants under construction and with consent and TEC confirmation from National Grid[123], it appears that independents are investing in variable shares of the different technologies (see Table B18 below).

Table C18 – Potential share of investment from independent developers (non-VI companies)[124]

	% of investment
Offshore wind	33%
Onshore wind	33%
CCGT	10%
Nuclear	0%
Other renewable	20%

310. The largest proportion of the forecast investment need is expected to be in the offshore wind sector. Analysis of the investor base for Rounds 1 and 2[125] for the offshore wind programme indicates that independents may account for around 50% of offshore wind capacity if all the projects in the pipeline are delivered.

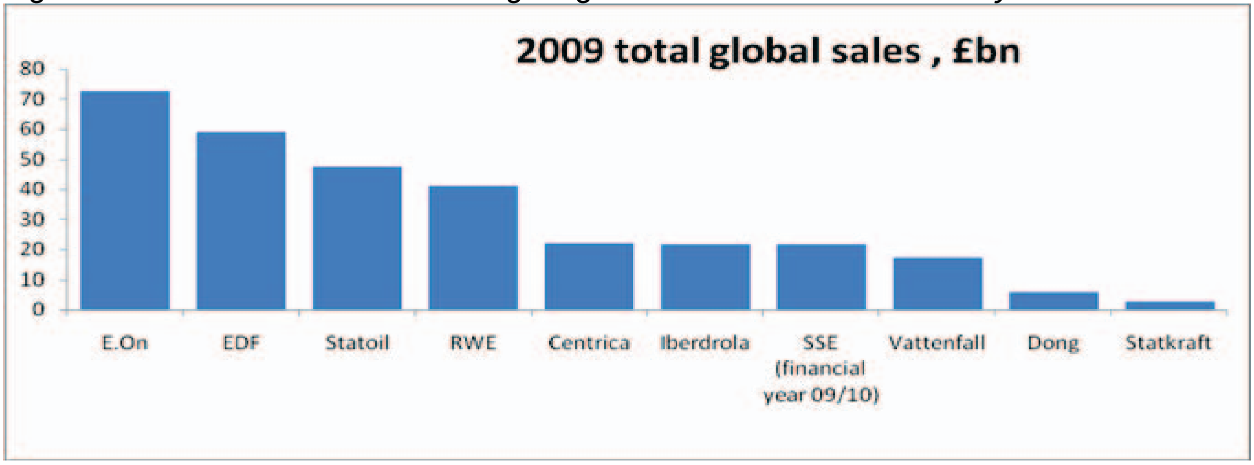
311. There is a question of whether the independent generators will be able to deliver the investment indicated by the analysis of the pipeline, and sustain this share in the future. There are no independents in the new nuclear segment, and the largest, riskiest investments required from independents are probably in the offshore wind sector. However, many of the independents in the offshore wind sector are large, well capitalised utilities which could be able to raise the finance required (see Figure C19). Nevertheless, there are likely to be other drivers that dictate their investment, for example companies will have different investment strategies and attitudes to risk so the degree to which they would chose to invest in the UK is uncertain.

312. Using the pipeline analysis data sources as upper and lower bound estimates of the share of supply of capital from independents, we estimate that this would still require the Big 6 utilities to raise c. £4-5bn p.a. on their balance sheets in order to meet the financing requirements in new generation assets, in addition to being the most likely power purchasers for independent generators. This could be very challenging, and is likely to stretch the Big 6 utilities to their maximum in an environment of declining earnings and pressure from rating agencies. Furthermore, any potential changes in strategy by the

[122] PwC (2010) “Meeting the 2020 Renewable energy targets: Filling the offshore wind financing gap”
[123] Analysis is based on projects that are currently under construction and projects with consent. Some of these projects might not materialise.
[124] Shares for wind and CCGT are from TEC, others are best guess DECC in-house estimates
[125] Source: Carbon Trust (2008) "Offshore wind power: big challenge, big opportunity"

energy companies would also affect the companies' ability to retain their current and predicted capex spend.

Figure C19 – Global sales of the largest generators in the UK electricity market



Project Finance

313. A large pool of capital is available from the project finance market to finance low-carbon generation investments, so long as risks can be accurately quantified and allocated through power purchase agreements, fuel supply contracts and EPC and O&M contracts. In 2009 for instance (at the peak of the credit crunch), a total of $75bn (£45bn) was raised in Europe, the Middle East and Africa (EMEA) countries[126].

314. However, low-carbon generation has attracted only small amounts of project finance – in the UK, wind farms - the dominant low-carbon investment currently- have attracted a total of £5.8bn over the last 5 years[127], with an average transaction size of only about £100m. This contrasts with the large amounts required for offshore wind (at c. £3.5bn/GW).

315. Project finance debt in the construction period has been limited to on-shore wind farms. The reason lenders are unwilling to lend to offshore wind or new nuclear in the development or construction phase is that key development, construction and technology risks cannot currently be mitigated through contracts with power purchasers, EPC or O&M contractors and/or fuel suppliers, and must therefore be borne by the providers of finance. For the same reason, the Government expects that it will continue to be difficult to attract equity from infrastructure funds and institutional investors into these assets. The situation is unlikely to improve with the introduction of new risk-adjusted liquidity and solvency regulations under the Basel Accord (called 'Basel III'), which may force banks to limit higher risk, long-term lending, potentially restricting the flow of credit to low-carbon generation assets.

316. The area in which project finance could play the most significant role (apart from construction-period financing of well-structured on-shore wind projects) is anticipated to be in refinancing operational offshore wind and (in time) new nuclear assets. However, whilst this may help existing investors to refinance projects and transfer them off their balance sheets (and so recycle their capital and manage their capex programmes better), rating agencies may continue to put pressure on utilities by including liabilities under power purchase agreements in their calculation of credit ratios and so ultimately this practice may not relieve pressures on balance sheets and the ability to raise more finance.

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[126] Source: Thomson Reuters

[127] Source: Preqin.

Conclusions

317. This analysis suggests that raising the required finance will prove a challenge and it is unlikely that the existing investor base will be able to provide the necessary finance to support the pace and scale of investment needed. If the existing investor base constrain their overall capital expenditure over the next decade, then meeting the investment challenge in the UK will require one or more of the following:

- The Big 6 utilities and other investors increasing their allocation of group level capex spend in the UK relative to other regional markets;
- Greater recycling of capital from utilities to independents and institutional investors once construction is complete (including a greater ability to refinance projects using project finance);
- Greater participation from independents in the construction phase of projects.

13.2 Impact of packages on the availability of finance

318. The discussion above shows that financing the capital expenditure in low-carbon generation will prove a challenge in the next decade and beyond.

319. Three instruments as alternative ways of incentivising investment in low-carbon generation have been considered: premium payments, fixed payments and CfD. The section below assesses the impact of each of these options on:

- The relative attractiveness of the UK market;
- The relative ability of utilities to recycle their capital post-construction;
- The ability of utilities to bring in co-investors;
- The relative ability to attract independents into the construction phase of projects.

Relative attractiveness of the UK market

320. Table C19 provides our initial qualitative assessment of the three de-carbonisation instruments on improving the attractiveness of the UK market (other things being equal):

Table C19 - qualitative assessment of the three de-carbonisation instruments on improving the attractiveness of the UK market

Criteria	Baseline	Premium payments	Fixed payments	CfD
Risk/return ratio	High	Medium	Low	Low
Simplicity	Complex	Simple	Simple	Complex
Policy stability	In flux	Stable	Stable	Stable
Predictability of regulations	Subject to regular review	More predictable	More predictable	More predictable
Signal of political commitment	Variable[128]	Strong	Strong	Strong

321. The table suggests that all EMR options will improve the relative attractiveness of the UK (once time has passed for instruments to "bed-in") by creating a more long-term, stable and predictable market arrangement. However, fixed payments are likely to have the largest relative effect mainly because they are simple to understand, backed by a credit-worthy entity and remove balancing and grid access costs for investors. They are also widely used in other markets like Spain and Germany, and so much more easily understood than the RO regime. In comparison, CfD are a comparatively novel

[128] Very strong commitment in respect of renewables, relatively less so in respect of new nuclear.

instrument, which will require new implementation mechanisms that will take time to develop and explain to new investors.

Recycling of utility capital

322. Utilities in general do not have a deliberate strategy of recycling capital by refinancing their generation assets. However, if accumulating capital expenditure demands did put utility balance sheets under unbearable strain, capital recycling may offer one way to reduce this pressure (depending on how the refinancing is structured).

323. All else equal, new investors such as banks, infrastructure funds and (possibly) pension funds are expected to prefer fixed payments because of their simplicity, the high credit rating of the power purchaser (Government) and the long-term inflation-linked duration of the tariffs. This makes it comparatively easier to refinance projects with fixed payments than with other instruments: premium payment and CfD options will continue to require sponsors to negotiate a PPA with a supplier.

324. When utilities offer PPAs, credit rating agencies can require them to continue to account for them on-balance sheet: this is particularly the case where utilities retain exclusive use of the majority or all of the output of the generator. This means that less "space" is freed up on the utility balance sheet by the refinancing, since rating agencies may include PPA liabilities in calculating credit ratios. Fixed payments maintain the potential to refinance a project without the need to offer a PPA, and therefore could free up space on the utility balance sheets.

325. With a CfD, it is uncertain whether the specific removal of price risks will improve utilities' ability to recycle their capital once projects are operational. This is central to the ability of CfD to enable access to new sources of finance because if projects continue to be consolidated on to the balance sheet of the power purchaser even with project finance, then utilities will have very little incentive to undertake refinancing using this route. The Government will be testing this point with utilities, banks and rating agencies during the consultation period.

Table C20 - qualitative assessment of the three de-carbonisation instruments on improving the recycling of utility capital

Criteria	Baseline	Premium Payment	Fixed payments	CfD
Attractiveness to new lenders (infra funds, banks)	Low	Medium	High	High
Balance sheet impact of refinancing	Targeted	Targeted	Full	Full

Ability to introduce co-investors

326. Potential co-investors alongside utilities could be:

- Other utilities (e.g. EdF introduced Centrica as a co-investor into new nuclear, while Iberdrola joined forces with GdF and SSE). There are other European utilities currently not playing in the UK market such as Enel, Endesa, and CEZ that might be attracted into the UK. Similarly, large American utilities such as Duke and Constellation could be attracted as co-investors into the UK market. Some companies are already moving towards a co-investor model. In general, entities who are not otherwise vertically integrated utilities (and hence have limited appetite to take on wholesale electricity price risk) will be easier to attract as co-investors into projects the greater the extent to which the government is able to provide revenue certainty. However, not all investors are alike. Some new entrants in the current market are working on a business model that relies on selling power on a merchant basis, and these players may actually be attracted by the potential upsides from electricity price exposure. Further, as with other investors, non-revenue risks such as development, construction and performance may continue to deter co-investors who do not feel well placed to manage these risks.

- Equipment suppliers and EPC contractors (such as GE, Fluor and Siemens Projects). Equipment suppliers and contractors usually take a strategic interest in projects where they are also selling other services to the project, such as equipment and/or engineering. These types of co-investors are much less likely to be geared up to manage wholesale electricity price risk. Therefore, greater revenue certainty should make it easier to attract them to projects as co-investors (with the same caveat as above).

- Financial investors such as banks, pension funds, infrastructure funds and private equity. However, these investor groups are less likely to invest during the construction phase (even with market reforms) as the characteristics of greenfield energy generation (with high construction risk) do not suit their target investment criteria: with the exception of private equity, they generally seek low risk, stable cashflow-generating operational assets. Private equity funds on the other hand may be attracted into greenfield investments, but typically seek rates of return in excess of 18%, which are well above those available from these assets.

Table C21 - qualitative assessment of the three de-carbonisation instruments on improving the ability to introduce co-investors

Criteria	Baseline	Premium Payment	Fixed payments	CfD
Attractiveness to other utilities	Low	Medium	High	High
Attractiveness to equipment suppliers/EPC contractors	Low	Low	High	High
Attractiveness to financial investors	Low	Low	Medium	Medium

Increasing the market share of independents

327. There are already a number of independent generators operating in the UK, mainly in the renewable market such as Dong, EDP, Vattenfall, RES, GE/Siemens and a variety of smaller players particularly in the on-shore wind sector. The market share of independents in the generation sector is already 30-50%, based on an EMR analysis of the existing pipeline. Given that most large independents are already in the market, expending this list much further will be challenging. There are unlikely to be independents in the new nuclear or CCS market for the foreseeable future due to the scale and construction risks involved in the former, and the technology risks associated with the latter.

328. The two main constraints on the expansion of the market share of independents are:

- The availability of PPAs from utilities (although some do take merchant risk)[129]; and
- The risk-return profile of projects (e.g. the pool of available investors tends to shrink as one moves up the risk-return curve, and only certain kinds of players may feel comfortable taking on the significant risks associated with new nuclear build or offshore wind)

[129] Although the injection of any form of project finance debt will require a well-structured PPA with a credit-worthy power purchaser.

329. All else being equal, the availability of feed-in tariffs or CfD should have the greatest relative effect on inducing greater investment from independents, particularly if these are offered on better terms than those offered in the market by suppliers and are easier and more transparent to access.

Table C22 - qualitative assessment of the three de-carbonisation instruments on lower barriers to entry for independents

Criteria	Baseline	Premium Payment	Fixed payments	CfD
Lowering barriers to entry for independents	Moderate	Moderate	High	High

Conclusions

330. From the analysis above, our initial conclusion is that fixed payments are likely to offer the greatest relative potential to attract new investors on account of their simplicity, their ability to de-risk projects and their ability to induce co-investment and new investment from independents. CfD ought in theory to have a similar effect, but the relative novelty of the instrument, the fact offtake risk is not removed and its complexity may limit this effect at least until it becomes established. Premium payments are likely to be similar in their ability to attract new investors as current arrangements. Non-revenue risks relating to the development, construction and operation of low-carbon generation assets may also continue to deter new investors, in spite of the greater revenue certainty created by EMR reforms.

14.0 Other specific impacts

331. 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.

332. Impact of the options consulted on by **rurality** is considered in (see table C11).

333. An initial assessment of **environmental impacts** and impacts on **health** are considered in the air quality assessment (section 5.4.5), although we will provide a full impact-pathway assessment for more robust estimates of air quality impacts for the EMR White Paper.

334. There could be **intergenerational** impacts in terms of changes to wholesale electricity prices and electricity bills (see table C14).

15.0 Summary and conclusions

335. Five different options for driving investment in low-carbon generation have been considered: premium payments, carbon price support (CPS), an emissions performance standard (EPS), contracts for difference (CfD) and fixed payments. These mechanisms have been considered both in terms of how they drive investment when used in isolation but also the costs and benefits of using some of them in combination.

336. This analysis suggests that, when used in isolation, all of these options are capable of driving investment in low-carbon generation to a level that is consistent with longer term decarbonisation goals. The performance of these options has therefore been tested

against their ability to deliver the Government's three electricity market objectives (decarbonisation, security of supply and affordability) and the following criteria:

- **Decarbonisation**: the modelling suggests that investment in low-carbon generation happens earlier with fixed payments and contracts for difference (CfD) given the certainty they provide for capital-intensive low-carbon projects. CfDs and fixed payments also provide more certainty that carbon targets will be met as they are more robust to both low gas prices and low-carbon price scenarios, because decisions to invest in low-carbon generation are largely unaffected by changes in the electricity price. Premium payments would need to be increased (for new installations) to meet decarbonisation targets in low gas or carbon price scenarios. Carbon price support (CPS) would also need to be increased in a low gas price world but is robust to low carbon price scenarios. Both CPS and EPS result in more coal to gas switching in the 2010s, meaning that cumulative emissions are lower for these options (although EU level emissions would be unchanged because of the EU ETS cap).

- **Security of supply**: the potential impacts on security of supply are complex and dependent amongst other things on the technologies that the options incentivise. No clear conclusions as to the comparative performance of the options can be drawn from this analysis.

- **Affordability**: all feed-in tariffs will result in lower financing costs than the base line. In particular, fixed payments and CfD result in lower financing costs and limit the potential for excessive rents as they are not dependent on how investors view the future electricity price; this leads to lower costs for consumers than under the other three mechanisms. Premium payments result in higher costs for consumers largely due to lower costs of capital and investors' lack of foresight of a rising carbon price, with associated excessive rents for producers where electricity prices subsequently rise. However, by retaining full exposure to market incentives to operate efficiently it offers some benefits which are not reflected in the modelling and would offset some of these additional costs. CPS and EPS also both result in relatively high costs for consumers. CfD and fixed payments both lead to an overall benefit (lower bills on average) for consumers over the period between 2010 and 2030 when compared with the baseline; on average costs for consumers would be around 2% lower under CfD and fixed payments than the other options.

- **Cost-effectiveness**
  - Net welfare: the modelling suggests that fixed payments and CfD are preferable in the terms of net welfare as they result in lower costs of capital given the higher level of investor certainty provided. There are though some costs to government, and ultimately the consumer, of this transfer that are not fully captured in this analysis. Premium payments, CPS and EPS (when used in isolation) are more costly in terms of net welfare as they do not provide the same degree of certainty to investors. In net present value terms (NPV), overall cost to society under premium payments would be approximately £4bn higher than under fixed payments and CfD (ie an NPV of around -£8bn). In a high demand scenario, with demand in 2030 30% higher than in 2010, both CfD and fixed payments have a positive NPV (around £6bn over the period).
  - Efficiency: fixed payments removes generator exposure to electricity price and offtake risks, resulting in loss of market efficiency benefits. Whilst these benefits are relatively small for certain technologies such as wind, they may be more important in the future and are potentially more significant for other technologies such as nuclear and CCS. Premium payments, CfD, CPS and EPS all retain this link to different degrees, in particular CfDs are not exposed to long-term electricity price risk

- Incentive setting: fixed payments, CfD and premium payments all have the potential for incentives to be set incorrectly when compared to CPS and EPS.
- Barriers to entry: fixed payments should reduce barriers to entry significantly as they remove both price risk and offtake risk (the risk of not being able to sell the electricity you produce) from generators. Premium payments, CPS and EPS do not significantly reduce the barriers to entry that exist with the current market arrangements – although to the extent that they reduce the cost of capital they may facilitate more entry. CfD reduce barriers to entry though this effect may be limited as offtake risk is retained by generators.

* **Durability**: fixed payments and CfD are more robust to a high penetration of wind and nuclear power (and other low marginal cost plant), which pulls down the average electricity price, than the other three options that all depend on the wholesale price for their revenues. Modelling shows this starts to become an issue in the late 2020s.

* **Coherence – combining options**
  - *Premium payments and CPS*. Premium payments can be reduced when combined with CPS as the wholesale electricity price is higher. When combined with premium payments, CPS provides more revenue certainty than premium payments alone, which reduces financing costs, though the impact is relatively small.
  - *Fixed payments and CPS*. Payments to low-carbon generation under fixed payments do not change with the introduction of CPS as there is no link to the wholesale electricity price. However, CPS would continue to affect dispatch decisions of existing fossil-fuel power stations, i.e. encouraging coal to gas switching.
  - *CfD and CPS*. Similarly total payments to low-carbon generation under CfD do not change with the introduction of CPS. However in the CfD package, CPS does mean that generators receive a higher proportion of their income from the wholesale price and are therefore not as exposed to wholesale price fluctuations before the CfD is settled. CPS would also affect dispatch decisions of existing fossil-fuel power stations, i.e. encouraging coal to gas switching.
  - *Capacity mechanisms*. The impact of combining premium payments, CfD and fixed payments with different types of capacity mechanism were considered in the analysis, which demonstrated that the impacts of the two main types of capacity mechanisms (targeted and market wide) were not significantly altered by the choice of decarbonisation mechanism.

* **Practicality**
  - **Administrative costs**. The administrative costs resulting from any of the options depend on specific policy design, and as such work on refining these is ongoing as part of the policy development process. However broadly speaking the administrative costs will be related to the complexity of the system. As such, premium payments are likely to have the lowest administrative costs relative to CfD and fixed payments. The costs of fixed payments are likely to be highest given the need for a mechanism to feed the electricity procured through this route back into the market.
  - **Transitional issues**. Premium payments could be implemented on the same timescale as the RO Banding Review and could therefore also be implemented by 2013. This would, combined with the similarities to the RO, imply a low probability of an investment hiatus for renewables investment while investors learn to understand the new mechanism. A change to a fixed payment or CfD package implies an additional one or two years with high probability of investment hiatus for renewable investments.

- **Devolution**. Any move from the current the support mechanism for renewables could have complex implementation issues due to the extent that the RO is devolved to Scotland and Northern Ireland (NI). In 2009, almost half of UK renewable electricity installed capacity was situated in Scotland, and c.4% was in Northern Ireland. Government is committed to working with the Devolved Administrations on the implementation of any reforms.
- **The potential for market manipulation**. The potential for market manipulation is also largely related to the complexity of the system and the potential for the abuse of market power under any package. CfD are more complex than both fixed payments and premium payments, however fixed payments and CfD are both likely to reduce barriers to entry. Therefore overall, it is not clear whether the potential for market manipulation is significantly different between the options. This issue will be fully considered in the next stage of the EMR project.

- **Impact on the financing challenge.** This analysis suggests that raising the required finance will prove a challenge and could stretch the Big 6 utilities to their maximum. Fixed payments probably offer the greatest relative potential to attract new investors on account of their simplicity, their ability to de-risk projects and their ability to induce co-investment and new investment from independents. CfD ought in theory to have a similar effect, but the relative novelty of the instrument, the fact that offtake and imbalance risks remain with investors, and the relative complexity of CfD may limit their effect, at least until it becomes established. Premium payments are likely to be somewhat more attractive to new investors than the current arrangements as they are a more commonly used revenue support mechanism with which a broader investor base will be familiar.

337. Overall, when judged against these criteria CfD appear to perform better as they: provide certainty that decarbonisation goals will be achieved under various different scenarios, including low gas prices; result in lower costs of capital that reduce financing costs, given the certainty that they provide and; limit the potential for excessive rents. As a mechanism for driving sustained investment in low-carbon generation, CfD are also more robust against a world of declining average wholesale prices, likely to be particularly significant towards the end of the 2020s. Unlike fixed payments, CfD retain the link to the signals provided by the short-term electricity price and the key efficiency benefits that stem from this. CfD is therefore the preferred option as the core mechanism for driving low-carbon investment.

338. However given there remains some design and implementation issues to resolve, including the need for a robust reference price against which to settle the CfD, it is important to consider premium payments as a credible alternative. The Government will also need to consider the public finance implications of the two options.

Packages of options

339. CfD have been combined with CPS, a targeted capacity mechanism and a targeted EPS (set at a level that prevents the development of new unabated coal) to form the preferred package.

340. A targeted EPS is included as it sends a clear regulatory signal to investors in electricity generation, to support the economic signals from the carbon price. It builds on the Government's current policy that developers must demonstrate CCS on a proportion of a coal-fired power stations capacity, and provides a regime under which plant will be expected to operate. Unlike the carbon price, an EPS is not affected by movements in fossil fuel prices and it is therefore potentially more robust in a high fossil fuel price scenario. It therefore provides an important backstop.

341. CPS is included as it sends important signals in terms of the development and operation of unabated fossil fuel plant which in turn sends important signals to investors in low-carbon generation. In addition when it is combined with CfD, CPS means that generators receive a higher proportion of their income from the wholesale price and are therefore not as exposed to the wholesale price fluctuations before the CfD is settled. When combined with other decarbonisation options, the overall carbon price targeted by carbon price support does not need to be as high. This minimises concerns about a steep increase in the carbon price to 2020 and the impacts on existing generators (both fossil-fuel and low-carbon).

342. As above, given the issues around detailed design and implementation a premium payment package (premium payments, CPS, targeted capacity mechanism and EPS) is considered as a credible alternative package in the consultation document. This is discussed further in the summary and conclusions at the start of this impact assessment.

Annex 1: Current market arrangements and security of supply

Security of supply and system balancing

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.

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.

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 penalty (the cash-out price)[130] if they generate/consume a different amount to that they contracted for.

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) as it is not technically possible to do this through bilateral trading. National Grid does this by procuring a range of balancing services from flexible resource.

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) 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

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.

In a competitive market all electricity generators will bid at their short run marginal cost (SRMC)[131]. 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.

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.

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[132] of security of supply[133]. At the economically optimal level,

[130] It should be noted that cash-out is cost-reflective for those whose imbalance helps the system and only penal where it exacerbates the system imbalance.
[131] 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.
[132] We say level, but as there are a range of customer preferences, the reality is more like an optimal range.
[133] 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. Further, a perfect market should also incentivise the most economic mix of generation types.

How an energy-only market remunerates an efficient capacity mix

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).

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.

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.

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 2: More detailed descriptions of the proposed options

1. This annex sets out more detailed descriptions of the options in the IA and how they might work in the GB market.

Improving the operation of the current market

Reforms to the balancing arrangements

Calculation of cash-out payments

2. Current cash-out prices may not fully reflect the costs of ensuring supply and demand are in balance and at times will be too low. Reform of the 'cash-out' arrangements would likely be made through changes to the Balancing and Settlement Code by Ofgem after a Significant Code Review. The objective would be to ensure that the price paid by those out of balance is a truer reflection of the costs of that imbalance. Possible changes include:
    - *Changing to a single cash-out price*: we currently have a different system buy price and sell price, this provides a strong incentive to balance but is not very meaningful and, for example, introduces risk for renewable generators. We could have a single price (or one with a fixed spread between buy and sell).
    - *Changing to more marginal pricing*: Currently we have a pay-as-bid scheme and the imbalance price is the average of the most expensive 500MWh of balancing actions. Having marginal pricing would result in higher (and arguably more cost–reflective) prices at times.
    - *More effective allocation of reserve contract costs:* As part of its role as System Operator, National Grid procures several types of reserve services for system balancing in advance of gate closure, for example short term operating reserve (STOR). Currently the costs incurred by National Grid of procuring such short term reserves are socialised across all of industry through National Grid's use of system charges. These could be better targeted to the periods in which the reserve is actually utilised, this would enhance cost reflectivity.
    - *Putting a price on currently non-costed SO actions:* Customers could be compensated for involuntary voltage reductions and supply curtailments and the costs of these actions (currently effectively free) included into the cash-out price.
    - If necessary, as a back-stop to cash-out reform, an *ex post* penalty on suppliers who hadn't procured sufficient reserve capacity could also be used.

Improvements to procuring of balancing services

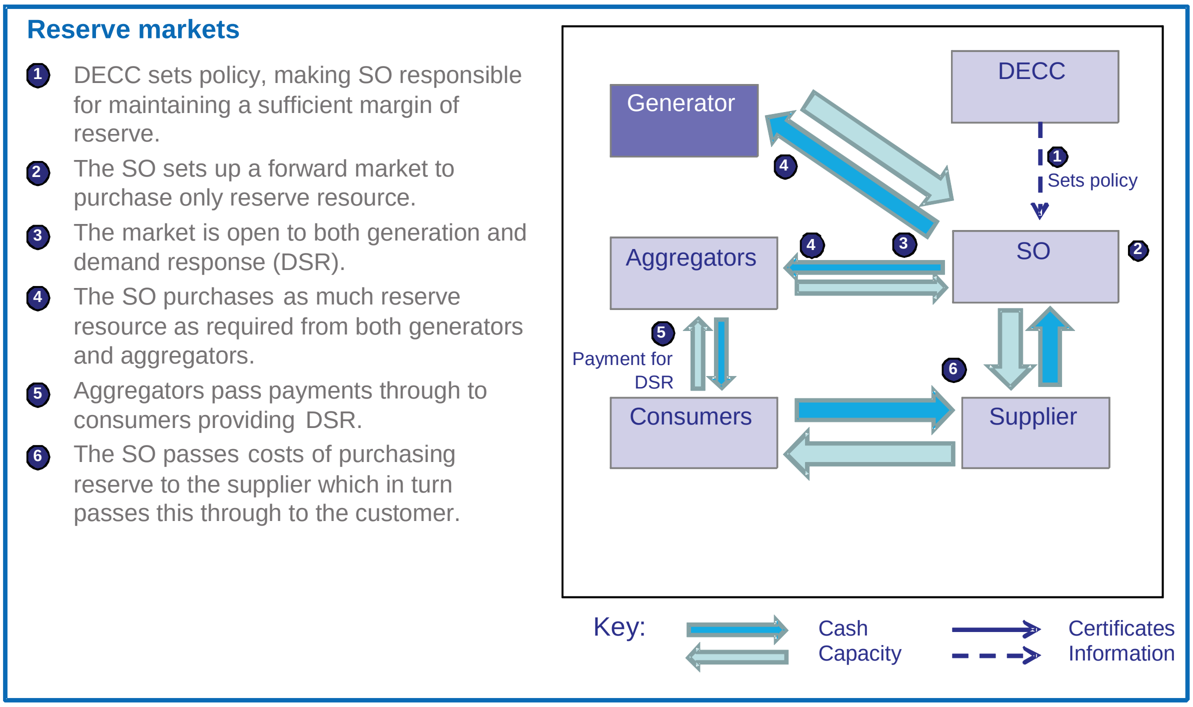
3. A further way to improve cost-reflectivity of cash-out and to also provide greater transparency is to introducing a reserve market. A reserve market is a short-term market (for example, day-ahead) run by the system operator to procure reserve resources. This would enable the value of reserve to be factored into the cash-out prices in a way that more accurately reflect conditions on the day, and therefore cash-out prices will be better targeted at the participants causing any shortfall[134].

4. In this model the System Operator runs an additional forward market to procure necessary additional reserve resource. This is in addition to reserve procured under longer term bilateral contracts similar to that currently operated by National Grid. A number of countries, e.g. Norway, have one.

[134] Ofgem Project Discovery consultation (Feb 2010)

5. Reserve Market conditions: -
   - The market should be open to both supply and demand side providers to enhance competition and to facilitate development of demand flexibility.
   - The contracted volume depends on expectations about wind patterns, temperature and load flow patterns for next week.
   - The SO would accept the lowest bids until their reserve needs are fulfilled.
   - Market participants would receive an option premium and be obliged to bid the contracted volume in the Balancing Mechanism.
   - Some ancillary services such as BM start up could possibly be transferred from the Balancing Mechanism into a day ahead market.
   - A weekly market allows greater flexibility for providers who may be able to offer either demand response or back up generation to fit with their production schedules.

Figure AN2.1: Reserve markets



Actions to manage intermittent renewables

6. A possible solution to reduce imbalance risk for intermittent renewable generators would be to organise a Centralised Renewables Market (CRM). This was proposed in Ofgem's Project Discovery. Ofgem subsequently commissioned the Brattle Group to further develop the proposal[135]. The report concludes:
   - The CRM should be a service, rather than a market. An agent called the Centralised Intermittent Renewables Aggregator, or "CIRA", would reduce imbalance exposure by aggregating intermittent renewable energy (IRE) and selling it using existing market mechanisms and products.

[135] Brattle Report - Alternative Trading Arrangements for Intermittent Renewable Power, December 2010, http://www.ofgem.gov.uk/Pages/MoreInformation.aspx?docid=169&refer=MARKETS/WHLMKTS/DISCOVERY

- Ofgem Project Discovery consultation (2010) assumed that the SO, could be responsible for CRM. However, this is not the only possibility, Brattle suggests on balance other entities may be more suited to undertaking the role.
- The fees the CIRA should charge for services should be regulated and subject to consultation and approval by Ofgem.
- The CIRA should be given responsibility for making intermittent generation forecasts and for submitting contract notifications (where IRE sales are not made via exchanges) and physical notifications. CIRA participants could also have an option to decide whether or not the CIRA should submit Balancing Mechanism bids and offers on their behalf.
- Sales of IRE should take place over a variety of timescales from day ahead down to close to real time.
- IRE generators should face the same imbalance prices as all other market participants. Rather than addressing the price of imbalances, the benefits of aggregation should reduce the quantity of imbalances for intermittent generators, and hence mean that the barrier to entry potential provided by imbalance costs will be reduced.
- The CIRA should be subject to incentives to maximise the revenues earned by intermittent generators and minimise their imbalance exposure.

Actions to improve liquidity

7. Ofgem has laid out four potential policy interventions to improve liquidity:
   - Obligations requiring large generators to trade with small/independent suppliers, a licence condition would be placed on large generators to require them to trade directly with small/independent suppliers. For example, this could involve requiring large generators to offer a wider range of smaller quantities of generation more suitable for smaller suppliers;.
   - Market making arrangements, supported by a licence obligation on the Big 6 to provide electricity in defined products: Under this option the Big 6 would be obliged to provide electricity to a “Market Making Agent” who would make this available to market participants via a trading platform;
   - Mandatory auctions of generation, supported by a licence condition on all large generators to offer a certain percentage of their output into an auction. The auction would focus on the prompt market with the aim of developing trusted reference prices and financial derivatives, or longer term products; and

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

8. Ofgem’s decision on whether to pursue any of these is due to follow their conclusions on progress in improvements to liquidity in Spring 2011.

Actions to improve diversity and the demand side

Demand Side Response (DSR)

9. For DSR to be fully effective the enabling technology and incentives for consumers need to be right. The main scope for immediate development lies in the industrial and commercial sectors with opportunities for aggregation of firm demand response, for example a supermarket chain being able to control usage of electricity for refrigeration across a whole

network of stores. The roll out of smart and advanced meters, should facilitate the uptake of DSR, and domestic consumption offers more potential post 2020 wit hthe likely electrification of heat and transport. The Government welcomes Ofgem initiatives which strive to facilitate DSR across the supply chain, including the Low-carbon Networks Fund and smart meter implementation.

Interconnection

10. The GB electricity system is relatively unconnected to other countries electricity systems[136]. Under the current arrangements, investments in interconnection are made on commercial terms, i.e. where developers identify an opportunity for arbitrage between markets then such investments take place. However, the nature of the investments make them high risk. As a response, Ofgem has proposed a new regulated approach to interconnector investment which will be trialled in 2011. There is widespread industry support for Ofgem's proposal as a way of increasing investment in interconnection.

Storage

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

Energy Efficiency

12. Government has a range of measures on energy efficiency, including the Carbon Emissions Reduction Target (CERT), and the Community Energy Saving Programme (CESP). These end in December 2012 and will be replaced by the Green Deal (see Box X) and a new Energy Company Obligation. An increase in DSR could also prove an important incentive to increasing energy efficiency across GB as a whole by increasing customers focus on how they can use energy more intelligently through use of energy management technology etc.

Capacity mechanisms

<u>Capacity payment</u>

1. This description is based on the capacity payment mechanism in the All Island Single Electricity Market of Ireland and Northern Ireland. A capacity payment reimburses all generators through a simple payment. The payment is defined to reimburse the market-widecapex of the newest peaking plant over the life of that plant. It is made up of a *ex ante* payment to provide certainty and *ex post* payment, to reduce gaming.

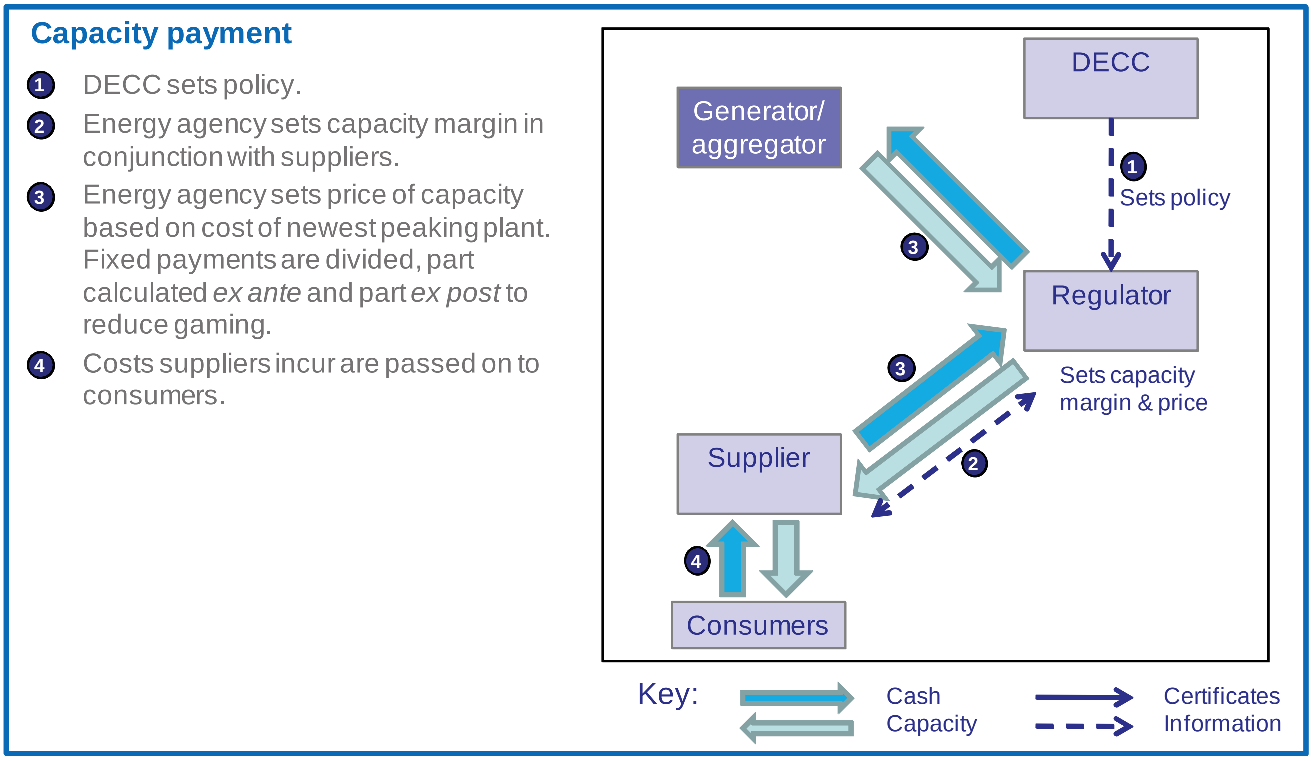
[136] There is currently about 2.5GW of interconnection capacity in the GB system, with links to the French and Irish markets.

How it would work in GB

2. A central agency (CA) calculates the required capacity at the start of the year, in conjunction with suppliers. For every half hour suppliers are charged for the capacity they use plus margin. Payment is collected monthly, to a central pot which reimburses generators for every half hour they declare themselves available. Suppliers pass the cost of capacity on to the consumer, either as separate charge or unit cost of electricity.

3. Generators not available when called are penalised, penalties are used to acquire capacity. Strict monitoring of the electricity price is important to ensure generators do not receive double payments. Monitoring of the electricity price requires a significant audit because the short run marginal cost of a peaking plant varies every half hour with staff costs, fuel costs, whether the plant ran in the previous half hour, whether it intends to run in the next half hour etc.

Figure AN2.2: Capacity payment



Capacity obligation

4. The price of capacity is set in bilateral contracts between suppliers and generators, the obligation is on suppliers to procure sufficient capacity. This is based on the UK Renewables Obligation.

How it would work in GB

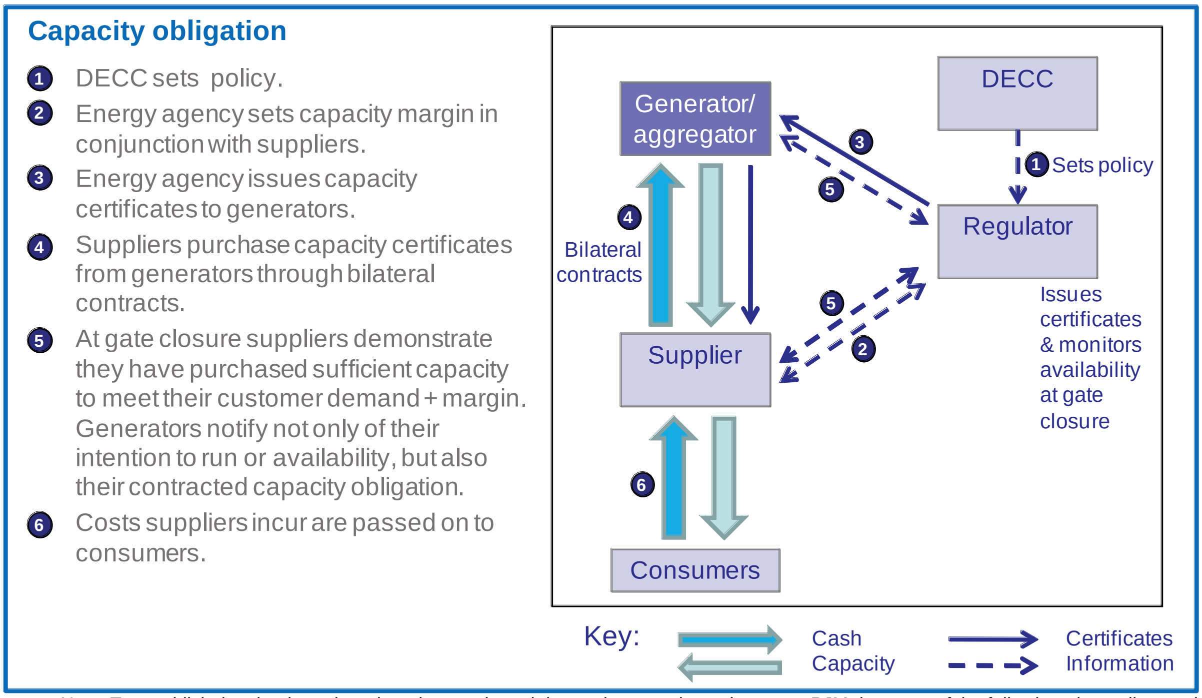
5. At the start of the year generators are issued with capacity certificates to reflect their de-rated capacity. Suppliers work in conjunction with the central agency to calculate their peak customer demand plus margin. Suppliers are then obliged to purchase capacity certificates to cover this capacity, allowing the price of capacity to be defined by the market.

6. At gate closure suppliers demonstrate they have purchased sufficient capacity to meet their customer demand plus margin. Generators notify not only of their intention to run or availability, but also their contracted capacity obligation.

7. The regulator will be responsible for monitoring all suppliers and generators every half hour to ensure they purchase/provide the correct amount of capacity. Generators will be penalised if they have sold capacity but are unexpectedly unavailable. Suppliers will be penalised if they do not purchase enough capacity. The short run marginal cost of electricity may also need to be monitored for double payments, which has same challenges as discussed under capacity payments.

Figure AN2.3: Capacity obligation

8.



Note: To establish the clearing price when the supply and demand curves do not intersect, PJM does one of the following, depending on the circumstance: 1) Short of supply - Extend the supply curve up vertically until it intersects the demand curve; 2) Short of demand - Extend the demand curve down vertically until it intersects the supply curve; or 3) Supply curve above demand curve - No capacity will be cleared.

Capacity auction

9. This model is based on PJM market in North America. The price of capacity is determined by the market, through auction. All contracted generators receive the auction clearing price of the marginal resource.

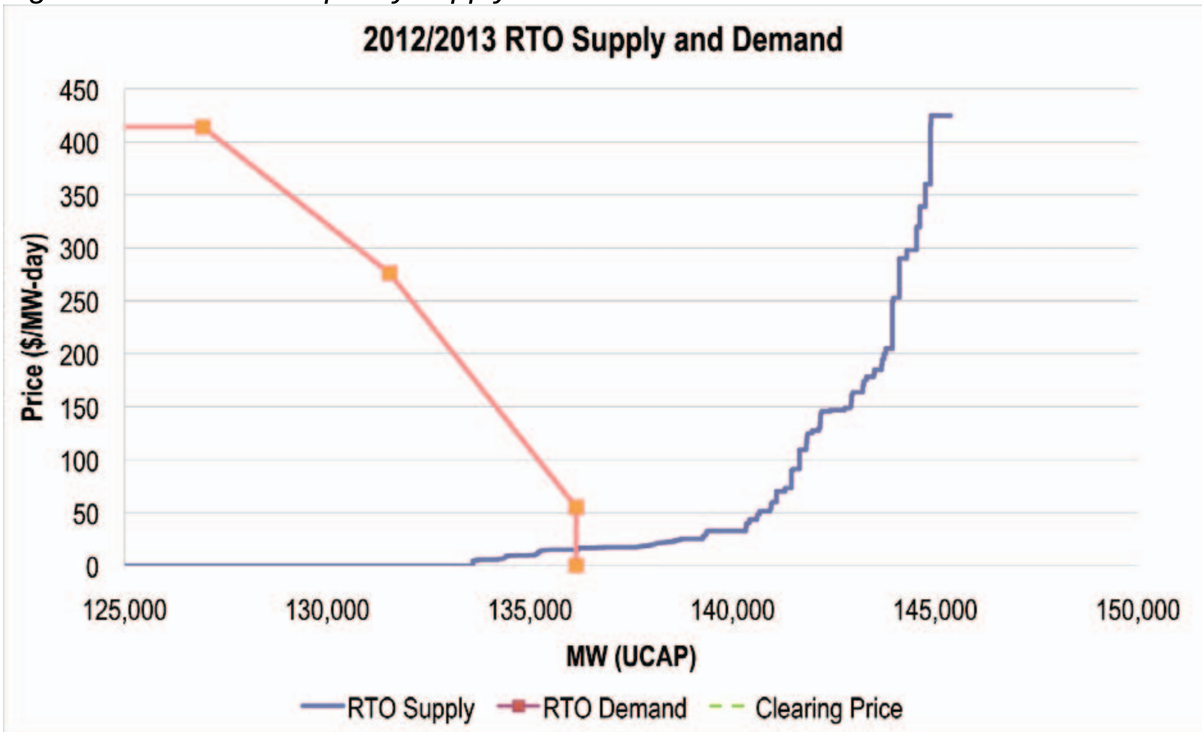
Reliability Pricing Model in PJM market

10. The current PJM market is a pool, with a forward capacity auction called Reliability Pricing Model. Demand side response and energy efficiency measures compete in the auction alongside generating capacity. All contracted resource receive the auction clearing price for the periods they are available, which is paid by an obligation on suppliers.

11. The independent SO holds a capacity auction three years in advance (Base Residual Auction). To reduce gaming a mechanism called the “Variable Resource Requirement”

adds demand elasticity to the auction. The required capacity is not fixed absolutely, as demonstrated in Figure X, below. At low prices the SO intentionally procures excess capacity, at high prices it procures less than target, leaving some to be procured in incremental auctions up to the delivery year.

Figure AN2.4 : PJM capacity supply and demand curve[137]



12. The Market Monitoring Unit (responsible for monitoring the PJM market), Monitoring Analytics, found no evidence of market power in the PJM capacity market during calendar year 2009[138]. Explicit market power mitigation rules in the Reliability Pricing Model offset the underlying market structure issues in the PJM Capacity Market. The PJM Capacity Market results were competitive during calendar year 2009.

13. The PJM capacity market is also open to demand side response and, in the most recent auction, energy efficiency. Table AN2.1 shows the resource offered and cleared in the five Base Residual Auctions since its inception since 2007. By not fixing the capacity price absolutely, the market has not been forced to accept all the resource offered.

Table AN2.1: Generation, Demand Resources, and Energy Efficiency Resources Offered and Cleared in PJM Base Residual Auctions (Unforced Capacity in MW)[139]

Delivery Year	**2008/2009**	**2009/2010**	**2010/2011**	**2011/2012**	**2012/2013**
Generation Offered	131,164	132,614	132,124	136,067	134,873
DR Offered	715	936	967	1,652	9,847
EE Offered*	-	-	-	-	652
Total Offered	**131,880**	**133,551.0**	**133,092**	**137,720**	**145,373**

[137] 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.
[138] PJM State of the Market Report, http://www.monitoringanalytics.com/reports/PJM_State_of_the_Market/2009/2009-som-pjm-volume2-sec5.pdf, p12

[139] Gottstein, op. cit., 2010.

Generation Cleared	129,061	131,338	131,251	130,856	128,527
DR Cleared	536	892	939	1,364	7,047
EE Cleared	0.0	0.0	0.0	0.0	568
Total Cleared	**129,597**	**132,231**	**132,190**	**132,221**	**136,143**

* Energy efficiency resources were first eligible in the 2012/2013 auction.
Note: Capacity cleared in the PJM auction is defined in terms of "unforced" capacity, that is the capacity of a resource adjusted for availability and deliverability based on historical performance (e.g., forced outages).

14. Table AN2.2 demonstrates that the clearing price has varied significantly over the five years. The significant increase in DSR clearing the market has been credited causing the drop in clearing price since 2010/11. The Market Monitoring Unit has estimated that the clearing price would have been $162 /MW/day higher if the market had not been open to DSR and energy efficiency, as shown in Table AN2.3.

Table AN2.2: PJM Base Residual Auction Clearing Price[140]

Delivery Year	**Clearing Prices ($/MW-day)**
2007/2008	$40.80
2008/2009	$111.92
2009/2010	$102.04
2010/2011	$174.29
2011/2012	$110.00
2012/2013	$16.46

Note: The PJM market also has locational price adders, to reflect constrained zones. These values do not include any locational price adders. Simple conversion of $/MW-day to $/kW-month: multiply by 3 and divide by 100.

Table AN2.3 Effect of DSR and energy efficiency on the PJM Market clearing price 2012/13 Base Residual Auction [141]

Actual Auction Results		**Calculated Results Without Demand-Side Resources**		
Clearing Prices ($/MW-day)	**Cleared Unforced Capacity (MW)**	**Clearing Prices ($/MW-day)**	**Cleared Unforced Capacity (MW)**	**Savings** ($/MW-day)
$16.46	**136,143.5**	**$178.78**	**133,568.2**	**$162.32**

Note: Capacity cleared in the PJM auction is defined in terms of "unforced" capacity, that is the capacity of a resource adjusted for availability and deliverability based on historical performance (e.g., forced outages).

How it would work in GB

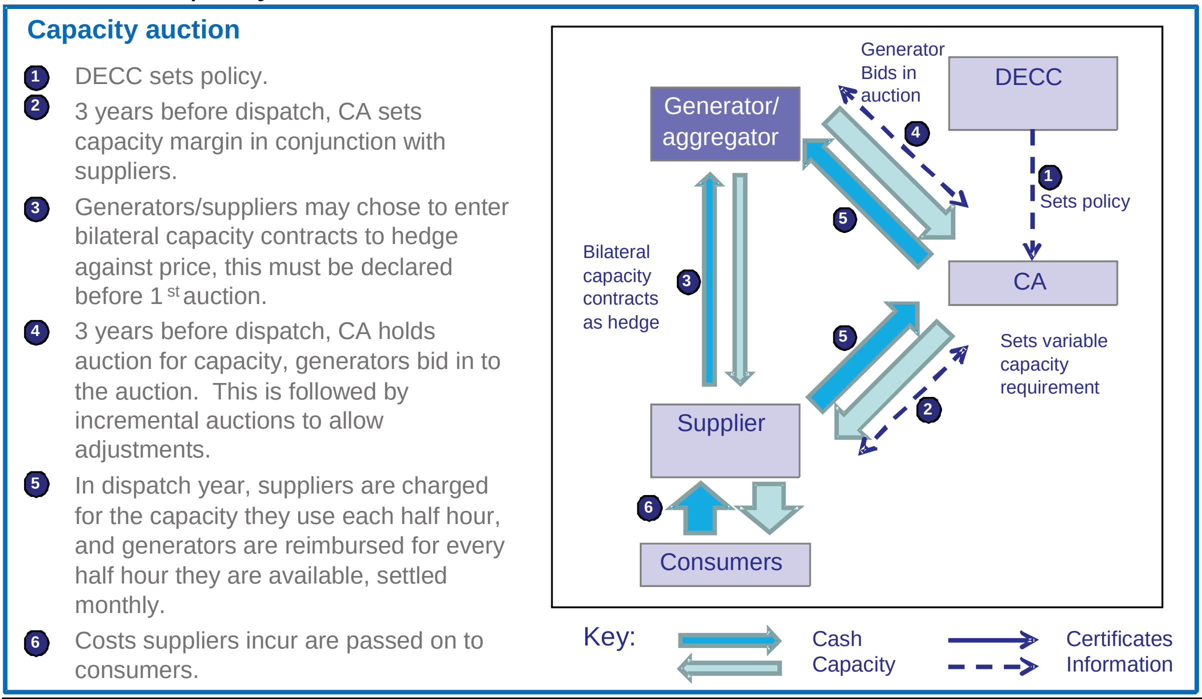
[140] Gottstein, op. cit., 2010.
[141] Bowring, Monitoring Analytics, Analysis of the 2012/2013 RPM Base Residual Auction, Table 20, http://monitoringanalytics.com/reports/Presentations/2009/Analysis_of_2012_2013_RPM_Base_Residual_Auction_20090910.pdf

15. The central agency calculates the required capacity three years in advance, in conjunction with suppliers, then auctioned. To reduce gaming the required capacity is not fixed absolutely, i.e. at low prices the central agency intentionally procures excess capacity, at high prices it procures less than target, leaving some to be procured in incremental auctions up to the delivery year. Incremental auctions allow participants to adjust their position.

16. Suppliers can chose to enter bilateral contracts independently with resource, this must be completed and declared before the first auction. Suppliers are charged the clearing price for all of the capacity they use, and credited the auction clearing price for any bilateral contracts (i.e. contracts provide hedge). Payments are for every half hour that the generator is available, settled monthly.

17. Resource has a pre-qualification assessment by the central agency before entering the auction. Generators that are unexpectedly unavailable will pay a fixed penalty plus the cost to procure additional capacity.

Figure AN2.5: Capacity auction



Reliability options

18. The price of reliability options is determined by the market, through auction. All contracted generators receive the clearing price. This capacity mechanism is untested internationally, so the details of the design are less defined than other policy options.

How it would work in GB

19. Three years in advance, the central agency sets a wholesale electricity strike price that represents system stress, slightly higher than the price normally be seen in a competitive market in non-shortage conditions. The central agency then holds an auction through which it buys enough reliability options to meet target system stress. This auction is

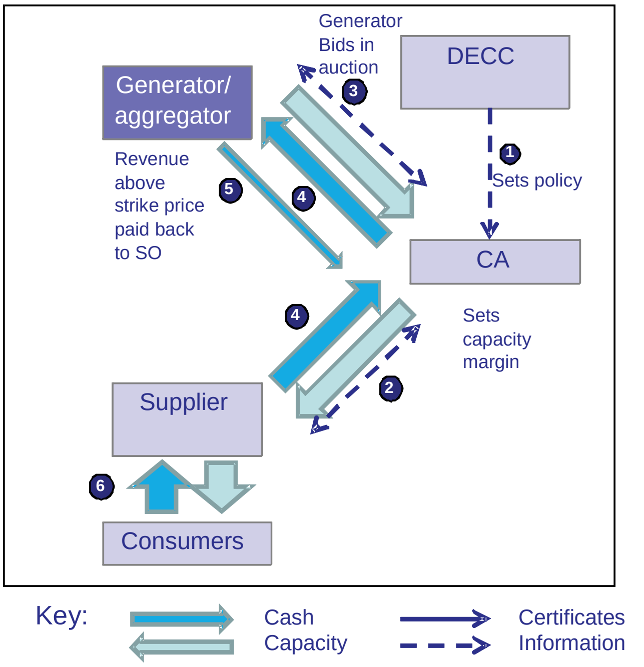
followed by incremental auctions up to the delivery year to allow participants to adjust their position. Contracted resource agrees to be available whenever the wholesale electricity price exceeds the strike price. When the spot price rises above the strike price any plant selling into the spot market pays back the difference in electricity price to the central agency.

20. Any generator unavailable when the spot price exceeds the strike price will be charged a fixed penalty plus the cost to procure additional capacity.

Figure AN2.6: Reliability options

Reliability options

1. DECC sets policy.
2. 3 years before dispatch, CA sets capacity margin in conjunction with suppliers.
3. CA sets wholesale electricity strike price and holds auction for capacity above this strike price. Generators bid in to the auction. This is followed by incremental auctions to allow adjustments.
4. Suppliers are charged for the capacity they use each half hour, and generators are reimbursed for every half hour they are available, settled monthly.
5. If, on a given day, spot price exceeds the strike price then any plant selling into the spot market pays back the difference to the CA.
6. Costs suppliers incur are passed on to consumers.



Targeted CM: Tender for Targeted Resource/Extended STOR

21. This description is based upon the Swedish targeted capacity tender, Peak Load Reserve. The purpose of a Peak Load Reserve (PLR) is for Governments to secure a higher level of security of supply than is established by the market by procuring a pre decided volume of additional reserve via a tender process. In this example the price mechanism is used to avoid the additional reserve capacity distorting the market process.

Peak Load Reserve in Sweden

22. In Sweden, the SO is responsible for contracting up to 2000 MW of capacity of peak load reserve during the winter period, which can only be used in extraordinary circumstances[142].

23. The SO runs a procurement exercise, the Peak Load Reserve (PLR) action, offering a price for sufficient reserve to come forward. The tendering process has been run successfully for a number of years, and there are no plans to change this to a price-setting approach.

24. In this the supplier receives compensation to remain on standby and is also paid when activated. PLR normally sits outside the market; the SO controls the reserve and is only

[142] NordREG Peak Load Arrangements, Assessment of Nordel Guidelines, Report 2/2009.

offered on the rare occasions when there is insufficient supply to meet electricity demand. At these times the reserve is first offered into the commercial markets to allow a market based solution. PLR is offered at a price point which is just above the highest bid made in the market which did not achieve an increase in volume of capacity.

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

26. The provision for 2000 MW of PLR was first introduced in 2003, and it has not been necessary to increase this level of capacity. PLR has only been used for a very few number of hours per year (for example it was called on three times last winter, each time for only 1-2 hours)[143]. It is very difficult to predict when the peak tender will be called upon, because it tends to be at very cold times that the PLR is needed[144], and weather forecasting of temperature is often incorrect. As PLR is only called for a very few unpredictable number of hours it is unlikely that the system is exposed to significant gaming.

How it would work in GB

Initial Steps

27. A minimum operating margin required to guarantee security of supply for GB would need to be set by the Government in conjunction with the regulator (Ofgem) and System Operator National Grid.

28. Central agency to produce an annual System Operating Requirement report , forecasting the ability of the system to meet the requirement 3-4 years hence (the shortest timescale in which new OGCT plant could be procured).

Tendering procedure

29. If the operating margin was predicted to fall below the agreed required minimum, and it was clear that the additional reserves could not be achieved via normal market incentives, **the central agency could be charged with the responsibility for tendering for additional Peak Load Reserves.**

- An annual tendering procedure for the required resource capacity would be undertaken, the objective being to procure resource at the lowest possible price.
- Both supply and demand side should be invited to submit tenders both to enhance competition and to facilitate development of demand flexibility.
- EU rule based market procurement procedures to be used ensuring maximum transparency.
- Tendering process to be open to existing and potential market players.
- Maximum volume of the required peak reserve should be set in advance.

Activation and Pricing of Peak Load Reserves

[143] Personal communication with, NordREG (Regulator of the Swedish market)
[144] This is because a large proportion of heating in Sweden is electric

30. Peak Load Reserves (PLR) could be offered into the both the Power Exchange and the Balancing Mechanism. Preferably these markets should be liquid with many market players bidding with a good transparency of the available resources. PLR should be offered first in the commercial Power Exchange and then all residual PLR could be traded in the Balancing Mechanism.

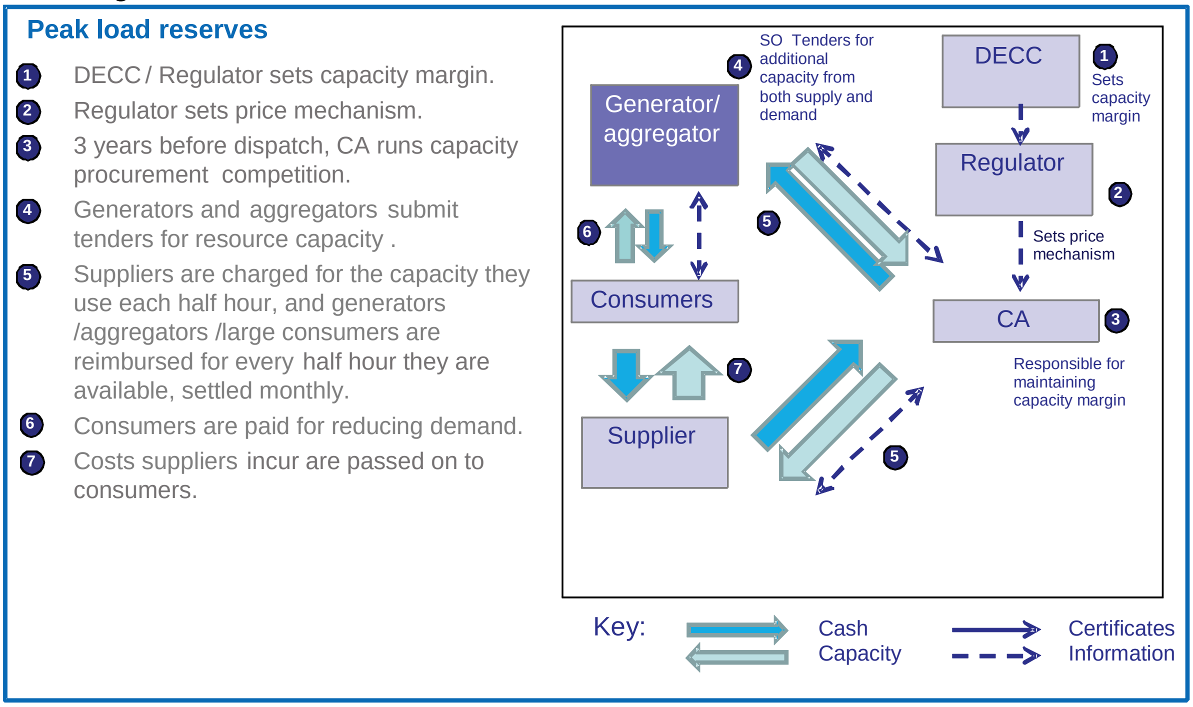
31. PLR should only be activated after all commercial bids have been activated and a balance of demand and supply has <u>not</u> be achieved. Pricing of PLR should not compete with commercial bids.

32. In the Swedish example the highest commercial bid in the spot market is the highest bid which achieves a volume change either by an increase in sales or a decrease in purchase in the market. The PLR bids are then submitted with the smallest possible price step in the spot market (0.1EUR/MWh). For example if the maximum commercial bid is EUR 1,501 per MWh then the PLR price will be EUR 1,501.1 per MWh. There are three pricing maxima in the Swedish system to cope with extreme balancing situations.

Extending STOR proposal

33. In this example, there would not be a strike price. The reserve would have to be available if called upon by central agency. When acting in this way, they would therefore not be able to sell their electricity in the market. The central agency would need to agree as part of the tender process the conditions for and payments for being dispatched. They would then need to consider how to use the STOR when balancing the market so that its use does not distort the dispatch order. The costs of the capacity payments to the STOR would need to be reallocated effectively into the cash-out price to avoid distortions

Figure AN2.7: Peak load reserves



Annex 3: Distributional Impact Analysis: Methodology

The absolute retail price impacts were estimated as the change in wholesale prices due to the scenario under examination (against the baseline) plus the demand weighted increase in the net support cost (against the baseline).

The absolute bill impacts for the distributional analysis were estimated by multiplying the absolute retail price impacts by final electricity consumption (and 5% VAT for domestic customers).

Assumptions

The analysis:

- was based on DECC's fossil fuel price scenario consistent with an oil price of around $80 per barrel in 2020; and
- assumes no elasticity impacts – i.e. we do not include a second round effect of reduced electricity consumption as a result of higher prices.

Average household definition

For the estimated impacts on average household electricity bills, the average household electricity bill is not a definition related to anything other than energy consumption. We use total electricity consumption from the Digest of United Kingdom Energy Statistics (DUKES) and divide by the number of households to get average consumption per household before we apply the impacts of policies

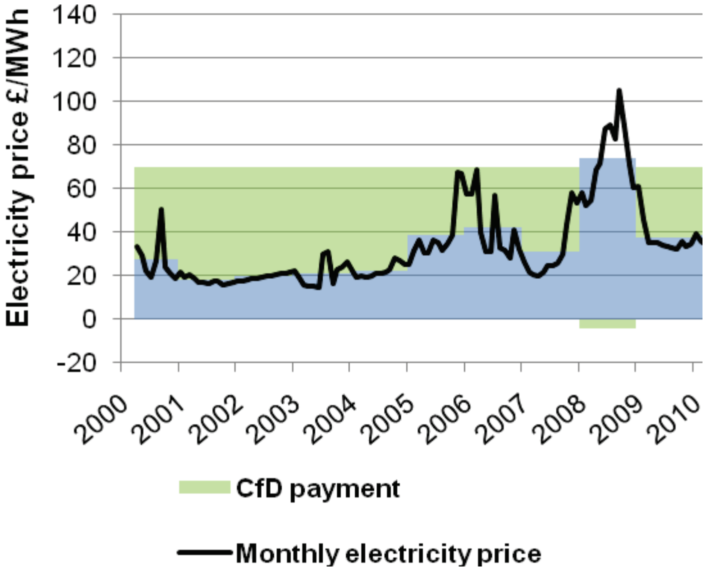
Annex 4 – the operation of a Contract For Difference (CfD) mechanism

1. Under a CfD mechanism for financial support to low-carbon generation, a long term contract would be settled between the generator and an agency administering the support payments.

The nature of the contracts

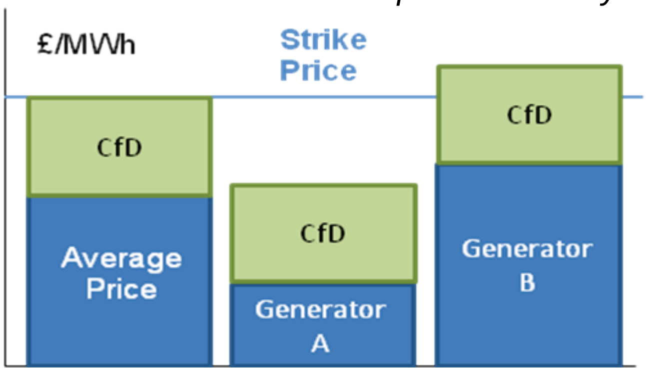
2. Long term contracts under a CfD would give more revenue certainty for low-carbon generation by providing an additional revenue stream to the generators. Generators' total revenue per unit of output would consist of two revenue streams. The first revenue stream would be variable revenues from the electricity the generator sells in the wholesale market, which is what conventional generators receive under the current system[145]. The second revenue stream would be a top-up payment calculated as the difference between an average market wholesale price (over a given period, e.g. a year) and an agreed ceiling tariff (a strike price possibly set at a the levelised cost of technologies).

Figure AN4.1: Illustrative revenues under a CfD mechanism



3. This dual revenue stream feature of a CfD would preserve the efficiencies of the price signal as it retains the current market incentive to dispatch when capacity margins are tight, in other words when prices are high.

Figure AN4.2: Illustration of maintained dispatch efficiency



4. The use of CfD would be a novel mechanism in the UK electricity market and there are a number of design and implementation issues that need addressing, including who will administer the scheme.

[145] Generators covered by the Renewable Obligation receives additional revenue streams

International examples of CfDs in electricity markets

5. The CfD model of revenue support is used in the Netherlands for renewable technologies, called a “sliding premium” because the size of the premium is related to the wholesale price. Generators have to sell their electricity (either into the wholesale market or in bilateral contracts) and then an energy agency pays them a monthly top up payment (differentiated by technology) up to the tariff level. The tariffs are decided by the government, and the top up calculated as the difference between the tariff price and the average annual spot market price. Contracts are signed by the energy agency for 15 years.

6. Denmark has since 2005 operated a Feed In Tariff for offshore wind similar to a CfD model. The support is set by means of a tender procedure. For the Anholt offshore wind farm (400MW), for example, a price supplement is calculated hour by hour as the difference between the offered price per kWh and the spot price for electricity in the relevant area. The total price supplement for any one hour is the product of the price supplement and the metered production for the same hour, with no supplement paid for production hours for which the spot price is not positive (only to apply for a maximum of 300 hours per year). The payments will be for a maximum of 20 years and a maximum of 20 TWh.

Annex 5 – International experience with auctioning

1. Auctioning can be used as a mechanism to determine the level of feed-in tariff support, regardless of the specific model for FIT chosen. The price discovery characteristic of an auction should enable financial support to be set at a level just high enough to lead to deployment but not high enough to lead to excessive profits, with bids driven down by competition.

2. Since it can be applied to any of the proposed direct support mechanisms (premium payments, fixed payments and CfD), the decision on the use of auctions has no effect on the preferred policy option. Examples of where auctions have been used in setting renewables support are illustrated below.

Offshore wind tenders in Denmark

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

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

5. The last tender had only one bidder, as opposed to three or four in previous rounds. The resulting higher-than-usual tariff however may also be related to the fact that the characteristics of the site are different from previous bidding rounds, and also that a benchmark for returns may be set by alternative investments in the UK and elsewhere.

Offshore wind tenders in the Netherlands

6. The Netherlands run tenders for a CfD support for offshore wind. Winners are determined on the amount of support needed only, no other criteria are used. Bidders need to provide financial guarantees, and a fixed penalty is applied for non- or late delivery.

Non Fossil Fuel Obligation

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

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

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

10. In practice the effectiveness of the orders in terms of new generation development was mixed. The tender rules meant that developers did not start the planning consent process

until after the tender had concluded and many failed to secure consent. No penalties were established for failure to deliver, so many more projects were not built whether due to cost estimates proving optimistic, finance being difficult to secure or technology shortcomings. Critics also cite a “winners’ curse” whereby bidders tended to be optimistic and subsequently regretted their bid, but payment at the strike price for the early Orders meant that this effect would have been marginal.

Annex 6 – Changes in annual net welfare, 2010-2030