Title: Electricity Market Reform – Capacity Mechanism	Impact Assessment (IA)
IA No: DECC0076	**Date:** 15/12/2011
	Stage: Final
Lead department or agency: DECC	**Source of intervention:** Domestic
	Type of measure: Primary legislation
Other departments or agencies:	**Contact for enquiries:** Anthony Tricot
Summary: Intervention and Options	**RPC:** N/A

Cost of Preferred (or more likely) Option				
Total Net Present Value	**Business Net Present Value**	**Net cost to business per year** (EANCB in 2009 prices)	**In scope of One-In, One-Out?**	**Measure qualifies as**
£-2.6bn			No	Tax and Spend

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

Over the next twenty years our electricity generation mix will move away from flexible fossil fuel generation and towards more intermittent and less flexible generation - with one fifth of flexible generating capacity expected to close over the next decade. There is a significant risk that the market will no longer deliver the level of security of supply it has historically delivered, principally because potential revenues in the energy-only market may not incentivise sufficient investment in capacity. This is the 'missing money' problem and may be caused by:

1. System Operator balancing actions in the Balancing Mechanism (such as voltage reduction) are not fully costed
2. Investors and existing players are concerned that the Government/regulator will not let wholesale energy market prices rise to levels that would incentivise sufficient new build/keep existing plant open.

There are additional market failures around reliability being a public good (so individual consumers cannot be disconnected) and barriers to entry (Government will be more likely to cap prices if it thinks market participants may be manipulating wholesale prices). A capacity mechanism reinforces signals from the energy-only market to ensure there will be sufficient flexible / despatchable capacity to meet peak demand.

What are the policy objectives and the intended effects?

The high level objectives of the capacity mechanism project are:

- **Security of Supply**: to incentivise sufficient investment in generation and non-generation capacity to ensure security of electricity supply;
- **Cost-effectiveness**: to implement changes at minimum cost to consumers; and
- **Avoid unintended consequences**: to minimise design risks and ensure compatibility with other policies.

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

This Impact Assessment looks at three options:

1. Business As Usual (BAU): No capacity mechanism is introduced. Other parts of the Electricity Market Reform (including Contracts for Difference) are implemented, and Ofgem reforms cash out regime.
2. Strategic Reserve: A targeted mechanism deployed as generator of last resort
3. Capacity Market: A market-wide volume-setting mechanism

The choice of Strategic Reserve and Capacity Market reflect analysis following the Electricity Market Reform White Paper consultation, and are assessed relative to the Business As Usual.

A Capacity Market is the preferred option as it best addresses the market failures and is robust to a range of scenarios. It should also reduce regulatory and market risks for investors, potentially reducing investment costs.

Will the policy be reviewed? It will be reviewed. **If applicable, set review date:** See Section 9

Does implementation go beyond minimum EU requirements?			**N/A**		
Are any of these organisations in scope? If Micros not exempted set out reason in Evidence Base.	**Micro** No	**< 20** No	**Small** No	**Medium** No	**Large** No
What is the CO2 equivalent change in greenhouse gas emissions? (Million tonnes CO2 equivalent)			**Traded:** -13 $MtCO_2$	**Non-traded:** 0	

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 Minister: Charles Hendry Date: 15/12/2011

Summary: Analysis & Evidence — Policy Option 1

Description: Business As Usual: Contract for Difference incentivises investment in low carbon capacity; investment in flexible capacity incentivised by prices in wholesale electricity market; Ofgem reforms cash out.

FULL ECONOMIC ASSESSMENT

Price Base Year 2011	PV Base Year 2010	Time Period Years 20	Net Benefit (Present Value (PV)) (£m)		
			Low:	High:	Best Estimate:

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

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

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

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

In the BAU intermittency on the system increases as up to a quarter of generating capacity in 2020 comes from wind and as one fifth of current capacity is set to retire between now and 2020.

Modelling suggests that the most likely outcome for 2024 in the central case is that there would be multiple voltage reductions, with December and January the likeliest months. Blackouts are possible but unlikely. There is a one in seven chance we would see blackouts affecting up to 2.5 million homes. There is a one in 20 chance we would see blackouts affecting up to five million homes, lasting more than 2 hours. Under some scenarios these effects could be more severe. In addition, in the do nothing scenario, wholesale prices are rising very high levels at times of scarcity leading to transfers between consumers and producers.

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

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

n/a

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

n/a

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

Prices in the wholesale energy market are assumed in the modelling to rise to the average value of lost load when there is scarcity. This relies on a) successful reforms to the cash out regime so prices can rise to this level and b) once implemented, the regulator and Government not intervening to prevent price spikes. The size of risk around this option depends on the extent to which recognised market failures in the electricity market (barriers to entry, reliability as a public good, and 'missing money') manifest in a security of supply problem in the future as the power sector is increasingly composed of intermittent / less flexible generators.

BUSINESS ASSESSMENT (Option 1)

Direct impact on business (Equivalent Annual) £m:			In scope of OIOO?	Measure qualifies as
Costs: n/a	**Benefits: n/a**	**Net: n/a**	No	N/A

Summary: Analysis & Evidence — Policy Option 2

Description: Strategic Reserve

FULL ECONOMIC ASSESSMENT

Price Base Year 2011	PV Base Year 2010	Time Period Years 20	Net Benefit (Present Value (PV)) (£m)		
			Low: -2734	High: -14	Best Estimate: -1,116

COSTS (£m)	Total Transition (Constant Price)	Years	Average Annual (excl. Transition) (Constant Price)	Total Cost (Present Value)
Low	7.3	2012 - 2023	0.6	**14**
High	5		291	**3,613**
Best Estimate	16		117	**1,336**

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

There are two main monetised costs:

1. Energy system costs: These include costs from building additional capacity and the associated impacts on fuel and carbon costs. These costs have a PV of £1.3 billion and are borne by consumers.
2. Institutional costs for a central deliverer to procure capacity for the Strategic Reserve – estimated to be £1m to set up and £2.2 million to run annually, with a discounted PV of £20 million in the central case. Institutional costs are lower in the transition period.

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

There may be overpayment of capacity in the Strategic Reserve if there is gaming of the capacity mechanism.

BENEFITS (£m)	Total Transition (Constant Price)	Years	Average Annual (excl. Transition) (Constant Price)	Total Benefit (Present Value)
Low			0	**0**
High			73	**879**
Best Estimate			19	**220**

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

A Strategic Reserve incentivises additional capacity which reduces the likelihood of blackouts and voltage reductions. This reduction in energy unserved is valued at £220 million.

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

A Strategic Reserve provides an insurance policy against the energy market failing to bring forward sufficient investment in capacity as a result of 'missing money'.

A Strategic Reserve is easy to implement and fits in well with the GB market setup.

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

Valuations of the costs of supply disruption (value of lost load) are highly uncertain. For the purposes of modelling, we have used a value of £10,000/MWh

A Strategic Reserve is assumed to operate as generator of last resort and is despatched at the value of lost load.

Costs assume that mechanism does not lead to a 'slippery slope' where additional capacity needs to be procured.

In the 'Central Case', the Strategic Reserve procures additional capacity by 2024. In the 'Low Cost' scenario there is no security of supply problem and the mechanism is not deployed. In the 'High Cost' scenario the Strategic Reserve is initiated immediately to provide additional capacity by 2016.

BUSINESS ASSESSMENT (Option 2)

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

Summary: Analysis & Evidence — Policy Option 3

Description: Capacity Market

FULL ECONOMIC ASSESSMENT

Price Base Year 2011	PV Base Year 2010	Time Period Years 20	Net Benefit (Present Value (PV)) (£m)		
			Low: -2,683	High: -27	Best Estimate: -2,613

COSTS (£m)	Total Transition (Constant Price)	Years	Average Annual (excl. Transition) (Constant Price)	Total Cost (Present Value)
Low	16.5	2012 - 2023	1.1	**27**
High	150		252	**2,951**
Best Estimate	101		249	**2,882**

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

There are three main monetised costs:

1. Energy system costs: These include costs from building additional capacity and the associated impacts on fuel and carbon costs. The impact on energy system costs have a lifetime PV of £2.7 billion. Distributional analysis shows that this cost is borne by generators who receive lower rents in the energy market.
2. Business administrative costs are estimated to be £14m per year that a capacity market is running with a PV of £97 million.
3. Institutional costs for a central deliverer to procure capacity for the Capacity Market – estimated to be £5 million to set up and £4 million to run annually, with a discounted PV of £39m in the central case. Institutional costs are lower in the transition period.

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

There may be overpayment of capacity in the Capacity Market if there is gaming of the capacity mechanism.

BENEFITS (£m)	Total Transition (Constant Price)	Years	Average Annual (excl. Transition) (Constant Price)	Total Benefit (Present Value)
Low			0	**0**
High			24	**269**
Best Estimate			24	**269**

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

A Capacity Market incentivises additional capacity which reduces the likelihood of blackouts and voltage reductions. This reduction in energy unserved is valued at £217 million.

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

A Capacity Market has a number of significant non-monetised benefits (discussed further in Section 6):

- a Capacity Market provides an insurance policy against an energy-only market failing to bring forward sufficient investment in capacity as a result of 'missing money';
- a Capacity Market provides a safer revenue stream for capacity providers which can help to bring on DSR
- a Capacity Market has the potential to reduce gaming opportunities in the energy market; and
- a Capacity Market reduces the volatility of consumer bills and potentially reduces bills overall in comparison with the BAU

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

A Capacity Market is modelled to operate as a Reliability Market – where participants in the Capacity Market take on reliability contracts, where they pay back the difference between the short term wholesale market price and the agreed strike price if they are unavailable when prices exceed the strike price. This assumption is for modelling purposes – detailed decisions on mechanism design will be taken as part of the next phase of work.

Valuations of the costs of supply disruption (i.e. the value of lost load) are highly uncertain. For the purposes of modelling, we have used a value of £10,000/MWh

In the 'Central Case' and 'High Case', the Capacity Market procures additional capacity by 2024. In the 'Low Cost' scenario there is no security of supply problem and the mechanism is not deployed.

BUSINESS ASSESSMENT (Option 3)

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

Evidence Base (for summary sheets)

Contents

1 Introduction

1.1 This impact assessment (IA) presents an appraisal of the options for a capacity mechanism to be introduced in the GB electricity market. The capacity mechanism forms part of the wider Electricity Market Reform package. This IA follows the consultation undertaken as part of the Electricity Market Reform White Paper (Planning our electric future, July 2011)[1] and accompanies the publication of a Technical Update to the White Paper.

1.2 The overall objective of this part of the Electricity Market Reform (Electricity Market Reform) programme is to ensure that an adequate level of security of electricity supply is delivered in a way that is cost-effective and complimentary to decarbonisation policies.

1.3 Over the coming years, the UK electricity market will undergo profound changes. Some of these changes will help make our electricity supply more secure – for example the increase in low-carbon generation will reduce reliance on energy imports. However over the next decade, we will lose around a fifth of existing capacity as a result of plant closures due to ageing plants and environmental regulation and we will see a significant rise in intermittent and less flexible generation to support our climate change objectives. Despite measures to improve energy efficiency, we also expect overall demand for electricity to increase in the long term as a result of the electrification of our transport and heating systems.

1.4 The Electricity Market Reform White Paper set out the case for the introduction of a capacity mechanism to ensure security of electricity supply. A capacity mechanism in effect offers an insurance policy against brownouts/blackouts due to the energy market not providing the economically optimal amount of capacity. A capacity mechanism does this by ensuring there is sufficient reliable and diverse capacity to meet demand, for example during winter anti-cyclonic conditions where demand is high and wind generation is low for a number of days. In practice, this means ensuring that appropriate incentives exist to bring on sufficient and appropriate flexible capacity (generating and non-generating) while the GB market sees a number of old flexible plants replaced, alongside and in advance of an effective demand side, greater interconnection and smarter networks.

1.5 The Technical Update sets out the findings of the consultation and the Government's decision to legislate for the introduction of a Capacity Market. This Impact Assessment complements the Technical Update by updating the analysis of the case for a capacity mechanism and showing why a Capacity Market is the preferred approach.

1.6 The latest energy system modelling supports the assessment in the Electricity Market Reform White Paper that capacity margins are likely to tighten and potentially become a significant cause for concern over the coming years, that preparing to introduce a capacity mechanism is justified as an insurance policy against an energy-only market failing to bring forward sufficient investment in capacity.

[1] Planning our electric future: a White Paper for secure, affordable and low-carbon electricity, July 2011

1.7 The leading options for a capacity mechanism, a Strategic Reserve and a Capacity Market, are assessed with quantitative and qualitative analysis. The quantitative analysis show that the net impacts of a Capacity Market are worse than those of a Strategic Reserve though a Capacity Market is better for consumers. However there are limitations on the extent to which this quantitative analysis can support a decision on the choice of capacity mechanism (these limitations are explained in more detail in Section 5). In practice, there are risks and wider impacts associated with the implementation of either option. The qualitative assessment (in Section 6) looks at those wider impacts and provides a more robust and comprehensive assessment of the options. Section 7 concludes that, based on all the analysis, a Capacity Market has greater benefits in terms of achieving security of supply and is potentially more cost-effective than a Strategic Reserve, though it does carry significant policy risk.

2 Objectives

2.1 The high level objectives of the Capacity Mechanism project are:

i) **Security of Supply:** to incentivise sufficient investment in generation and non-generation capacity to ensure security of electricity supplies.
ii) **Cost-effectiveness:** to implement changes at minimum cost to consumers.
iii) **Avoid unintended consequences:** to minimise design risks and ensure compatibility with other energy market policies, including decarbonising the power sector.

Security of Supply

2.2 The security of supply objective can be broken down into the following components:

- ensure enough generation or non-generation capacity is in place to meet peak demand levels and avoid blackouts and brownouts as a result of resource inadequacy;
- ensure providers of capacity have optimal incentives to be available at times of scarcity and minimise gaming opportunities in the energy market; and
- encourage all forms of capacity – including non-generation approaches such as demand side response (DSR), interconnection and storage – to play a role (where cost-effective) in ensuring security of supply.

Cost-effectiveness

2.3 The cost-effective objective can be broken down into the following components:

- Cost-efficiency: Ensure market operates efficiently by:
  - developing mechanism that is as simple/feasible to implement as possible and minimises administrative costs
  - seeking to avoid over-procuring capacity
  - seeking to procure the right mix of capacity
  - reducing barriers to entry to the energy market (or avoiding creating new barriers)
- Consumer impacts: Avoid over-paying energy companies at the expense of consumers by:
  - minimising creation of gaming opportunities in the capacity market; and
  - avoiding overpaying plant that already has appropriate reliability incentives

Minimise unintended consequences

2.4 The design risk and compatibility objective can be broken down into the following components:

- ensuring the mechanism is workable within the GB market;
- supporting other parts of the Electricity Market Reform programme aiming to decarbonise the power sector;
- ensuring that the mechanism is compatible with EU state aid rules;
- ensuring the mechanism minimises financial risk for DECC/ Whitehall; and
- ensuring mechanism is adaptable once implemented and that it is possible to return to an energy-only market if desired (i.e. the policy has an understood and straightforward ‘exit strategy’)

3 Rationale for Intervention

Introduction

3.1 Over the next twenty years, our electricity generation mix will move away from flexible fossil fuel generation and towards more intermittent and less flexible generation. This change will put pressure on the energy-only market's ability to ensure sufficient flexible/despatchable capacity to meet peak demand. Remuneration for such flexible capacity will be increasingly uncertain as more and more low marginal cost plant enters the market and pushes more flexible plant up the merit order.[2] Without action, this would mean flexible plant running less frequently and therefore increasingly relying on the very peaky prices that result at times of high demand and system stress in order to recoup their costs.

3.2 If the market worked perfectly, this would not be a problem as generators would have sufficient confidence that prices would spike to such an extent that would enable them to cover their costs. However, industry may not feel able t o invest if they do not have confidence that the regulated market will be allowed to operate in an unconstrained way; because of the potential for Government and the regulator to cap revenues to address concerns that market prices were being manipulated. As such, the level of flexible capacity required may not come forward, potentially resulting in costly blackouts/brownouts and an increase in wholesale prices and consumer bills at times of high demand and low wind. A capacity mechanism acts as an insurance policy against an energy-only market failing to deliver sufficient capacity for this reason.

3.3 In order to understand the potential scale of the capacity problem, we have:

- assessed theoretical failures in the energy market that could lead to insufficient investment in capacity; and
- carried out modelling of the energy sector under a range of plausible scenarios.

3.4 It is important to note that, given the inherent uncertainties and difficulties in predicting capacity margins, neither of these approaches can perfectly predict if, when and at what scale a capacity problem could materialise. However, they do help us to understand the potential scale of the problem and enable us to make a considered judgment based on a balance of risks.

Market failures

3.5 In the Electricity Market Reform White Paper, we set out the potential market and regulatory failures in the current market that could prevent these signals from being realised.

3.6 The principal market failure is that **reliability is a public good**: Customers cannot choose their desired level of reliability as the System Operator does not have the ability to selectively disconnect customers.

3.7 In theory this problem is addressed in an energy-only market by allowing prices to rise to a level reflecting the average value of lost load and allowing generators to receive scarcity rents invest in a socially optimal level of capacity.

3.8 However in reality an energy-only market may fail to send the correct market signals to ensure optimal security of supply. This is commonly referred to as the problem of '**missing money**', where the incentives to invest are reduced, due to the two reasons below:

[2] The order in which different generation technologies are despatched based on their short run marginal cost.

i) That the charges to generators who are out of balance in the Balancing Mechanism do not reflect the full costs of balancing actions taken by the System Operator (such as voltage reduction).
ii) That at times when the wholesale energy market prices peaks to high levels, investors are concerned that the Government/regulator will act on a perceived abuse of market power, for example through the introduction of a price cap.

3.9 The latter regulatory risk is exacerbated if there are significant **barriers to entry**, effectively restricting the number of participants in the wholesale electricity market. As margins become tighter and prices more volatile in the future, market participants may have more opportunities to withhold supply to drive up prices. The greater likelihood of gaming in the energy market and difficulties in differentiating such gaming from genuine scarcity conditions increase the risk that the Government may want to intervene in the wholesale market to cap prices. This has not previously been a significant concern as prices historically have not risen above £938/MWh[3] as a result of excess capacity on the system depressing wholesale market prices. In the future, analysis suggests the price could need to rise to £10,000/MWh for short periods to allow flexible plant to recover investment. Investors are concerned that Government or the regulator would intervene if this were to happen. The perception of this regulatory risk could increase 'missing money' and under-investment.

Modelling

3.10 We have used energy system modelling to assess the security of supply outlook:[4]

i) Increased intermittency on the system (we expect up to a quarter of generating capacity to be wind by 2020) leading to greater fluctuations in the electricity wholesale price because wind is not despatchable.
ii) 19GW (around 20 per cent) of total capacity is expected to come off the system between now and 2020, creating the challenge of ensuring we have enough flexible capacity to deliver security of supply. This compares to around 6GW of capacity coming off the system in the last decade. Our modelling also takes into account the possible closure and reduced running hours of fossil fuel plant as a result of the Industrial Emissions Directive.[5]

3.11 The increased risks around security of supply are likely to be exacerbated by the 'missing money' problem. Therefore in addition to looking at theoretical market failures, we have run further modelling to provide scenarios for de-rated capacity margins and the amount of lost load (leading to brownouts/blackouts)[6] that result.

3.12 We have modelled security of supply if no capacity mechanism is introduced under a number of scenarios:

i) DECC's revised central forecasts of energy demand and commodity prices.
ii) A scenario which includes a £1000/MWh price cap to model the impacts of a missing money problem.

[3] System buy price on 5th January 2009, settlement period 35. Balancing Mechanism Reporting System (BMRS), http://bmreports.com/
[4] Carried out by Redpoint Energy
[5] http://ec.europa.eu/environment/air/pollutants/stationary/ied/legislation.htm
[6] In practice, the System Operator runs through a series of actions before blackouts result. These include notice of insufficient margin; warning that demand control is imminent; followed by demand reduction, including voltage reductions and ultimately (if the situation is severe), disconnection.

iii) A stress test – i.e. a plausible, but more problematic scenario. This assumes greater electricity demand than in the central scenario and that a number of other plausible downside risks to security of supply materialise,[7]

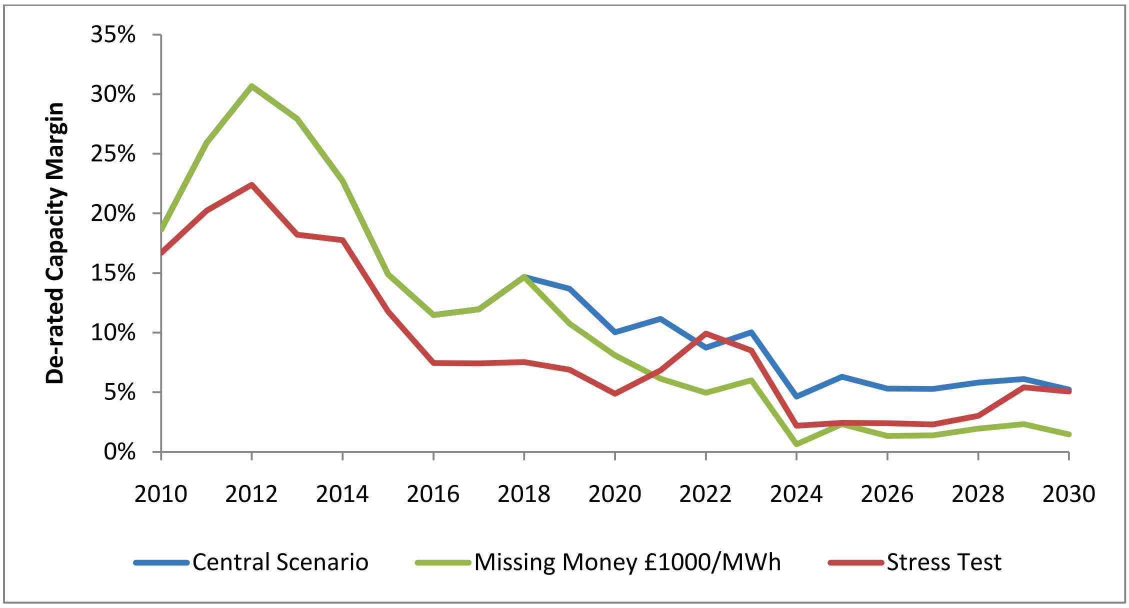
3.13 The £1000/MWh price cap model is based on the fact that historically prices have not spiked above £938/MWh, although it is noted that this is largely because there has been excess capacity on the system in the last twenty years depressing wholesale market prices.

3.14 Electricity demand in the central case is assumed to decline slightly over the period 2010 to 2020. The stress test on the other hand assumes that demand will increase, resulting in a greater shortage of capacity, and therefore higher price spikes in the energy market.

3.15 The energy system modelling takes an intentionally asymmetric approach – looking only at a central scenario and two plausible higher risk scenarios. In alternative plausible scenarios, particularly if electricity demand fall significantly, the risks around security of electricity supply would be lower and the rationale for intervention therefore weaker. We recognise that in scenarios with lower security of supply risks the mechanism would either not be deployed or have limited positive impact. This is later reflected in the 'low cost' scenario which assumes that the mechanism is never deployed but where costs are incurred in setting up the institutional capacity to deliver a capacity mechanism if need be.

3.16 The results of the energy system modelling are shown below in Figures 1 and 2. Figure 1 shows that de-rated capacity margins fall to low levels in 2024 in our central scenario – a benchmark for acceptable margins is around ten per cent. However, under the other modelled scenarios the security of supply issue occurs earlier and is more sustained.

Figure 1: De-rated capacity margin

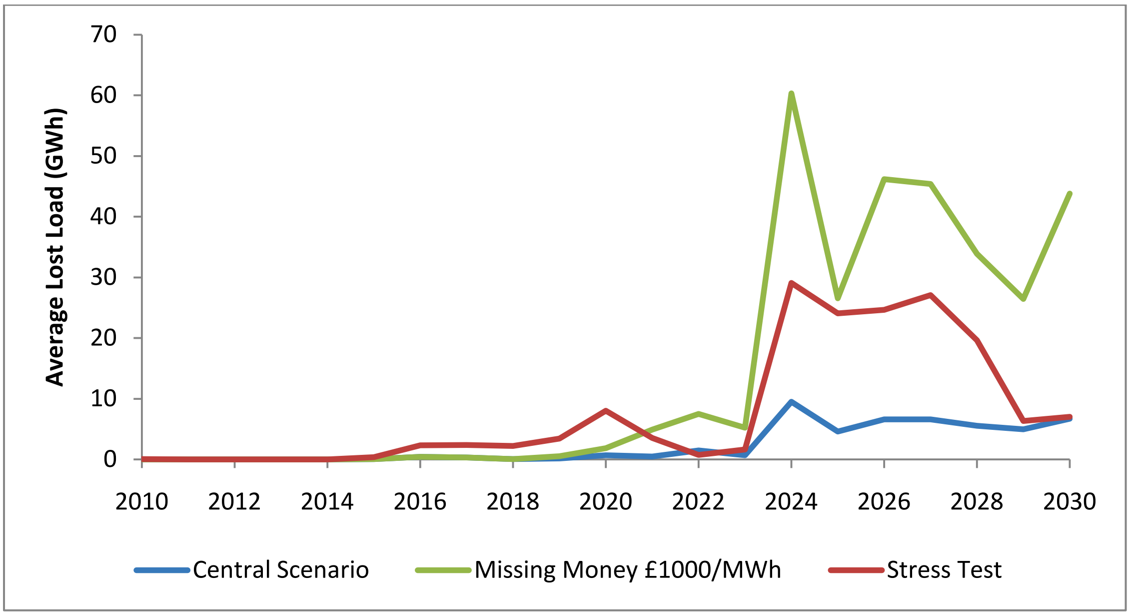


[7]The stress test includes a number of assumptions which will impact negatively on security of supply. Note that these assumptions are not in themselves implausible, but taken together, our judgement is that this represents a pessimistic appraisal of security of supply in the absence of a Capacity Mechanism. Key assumptions include:

- Demand following National Grid's assumed profile from their Gone Green scenario, rather than DECC UEP forecasts. This has increased demand, primarily because it is has less ambitious assumptions around what energy efficiency can deliver to 2020. In DECC's demand assumptions there is a large fall in electricity demand to 2020, whereas National Grid estimates a small rise. This is the most important difference in this scenario compared to the central scenario between now and 2020.
- A 2 year delay to the nuclear program meaning that the first new nuclear plant can only be built in 2021 rather than 2019.
- A moderate level of missing money, so that the maximum price in the wholesale electricity market would be £5,000/MWh rather than the £10,000/MWh price that is assumed in the central run.
- That biomass meets a lower proportion of our renewables targets than in the central scenario.
- An unexpected delay to 2GW of R3 offshore wind in 2021-22.

3.17 The amount of lost load (i.e. unserved energy) is shown in Figure 2 and, as would be expected, this is closely correlated to the level of de-rated capacity margins.

Figure 2: Energy Unserved



3.18 The energy system modelling illustrates the sorts of impacts that we might expect in some of the case study years that we have looked at. We have also used a probabilistic model from Redpoint to investigate the likelihood for experiencing different sorts of outage. This has looked at the likelihood of different sorts of load shedding incidents taking into account the variability of wind generation output and levels of demand and the likelihood that low supply occurs simultaneously to high demand.[8] The results from the modelling are then translated into levels of voltage reduction and blackouts affecting homes to illustrate what this would mean in practice. The table below shows the results from this analysis.

[8] This analysis uses 5000 iterations of each modelled year to see how often certain sorts of incidents take place.

Figure 3: Probability of blackouts in 2024 under different scenarios

	Probability of Voltage Reductions in 2024	Probability of blackouts for up to 2.5m homes in 2024	Probability of blackouts for up to 5m homes for more than 2 hours in 2024	Probability of blackouts for more than 5m homes lasting more than 10 hours in 2024
Central Scenario	Multiple incidents likely	1 in 7	1in 20	1 in 100
Stress Test	Multiple incidents likely	1 in 4	1 in 10	1 in 30
Missing Money £1000/kWh	Multiple incidents likely	1 in 3	1 in 10	1 in 15

3.19 There is a trade off between the cost of new capacity and security of supply. There is in theory an optimal level of security of supply at which point increased investment in generation capacity becomes more expensive than the value of the marginal reduction in energy unserved. Estimates of this optimal level are highly uncertain and depend on estimates of the costs that consumers place on supply disruption. This cost is known as the value of lost load. Some estimates of the value of lost load range between £5,000-30,000/MWh.[9] In practice, consumers are likely to have differing values, so even if there was certainty about the average value of lost load it would still be difficult to assess the optimal level of aggregate capacity.

3.20 The relationship between de-rated capacity margins and the expected level of energy un-served is not straightforward. Broadly speaking, low capacity margins mean a greater risk of energy unserved. But a small decrease in capacity margins can significantly increase the risk of unserved energy when overall margins are low, and have very little impact on unserved energy when overall margins are high.

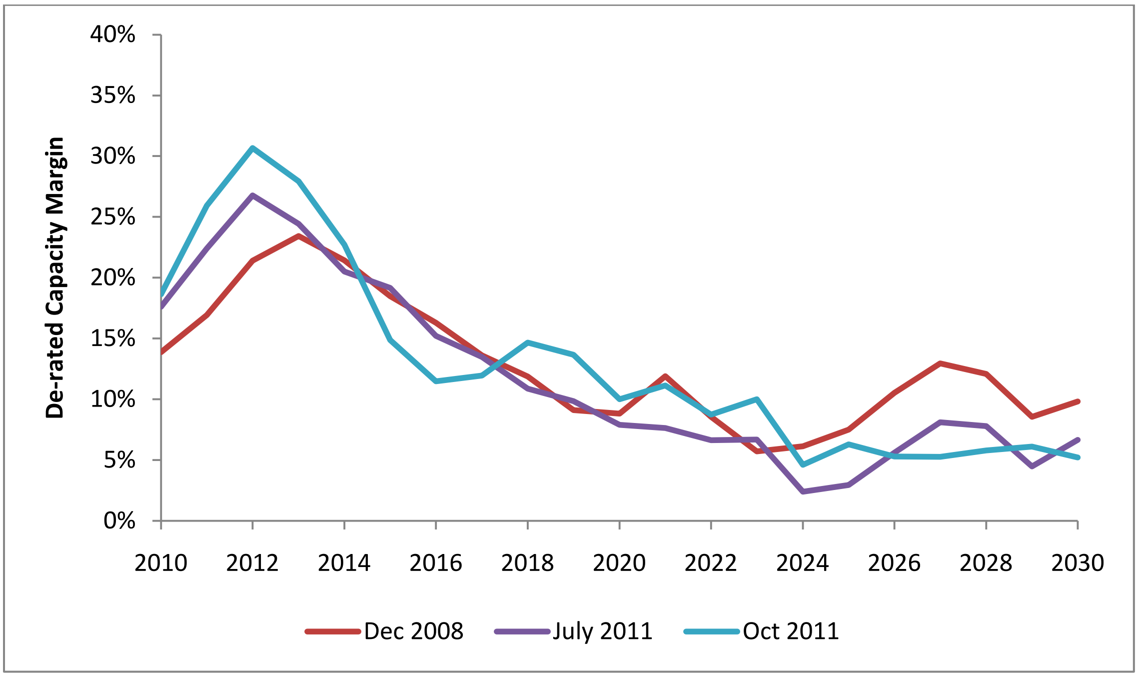
3.21 It is also important to note that the de-rated capacity margin is largely fixed several years before the day (because of lead times involved in new investment). Given the uncertainty over the conditions that will be present on the day, society may prefer to invest more to insure itself against the risk of more severe effects in terms of energy unserved. In the energy system modelling, we see ‘optimal’ de-rated capacity margins of around five per cent. In reality however, if we aim for a five per cent de-rated margin, because of uncertainty, we would be likely to end up at some lower or higher amount. Given that the costs of ending up at a lower de-rated margin are greater than the costs of ending up at an equivalently higher margin, it may be efficient to target a capacity level greater than what the energy modelling finds to be economically optimal.

Limitations of relying on an assessment of market failures and modelling

3.22 Assessment of market failures, and of modelling, is an important input to the decision on (a) whether we need a capacity mechanism; and (b) what type of mechanism we select. However given the inherent uncertainties, modelling future energy unserved cannot be precise or give absolute certainty on the extent to which a problem will materialise. For example, our most recent central scenario from October 2011 has changed compared to the central scenario in the Electricity Market Reform White Paper (June 2011) and that itself was a change from analysis done for the Renewable Energy Strategy (RES) in 2008-09. Figure 4 shows how the estimate of the size of the problem has fluctuated.

[9] Oxera report “What is the optimal level of electricity supply security”, (2005)

Figure 4: How the central assessment of derated capacity margins has changed



3.23 The difference between the central estimates provided in the Electricity Market Reform White Paper and the Technical Update has primarily been driven by DECC's revised central view of electricity demand. This is now forecast to be around 7.5 per cent lower in 2020 than was the case in the previous analysis in line with the latest DECC Updated Energy Projections (UEP).[10] The change is primarily a result of the assumed impacts of efficiency policies but also lower economic growth estimates in the latest UEP. That is why we have included a stress test which includes a number of plausible downside risks, including using National Grid's central demand forecasts, which are significantly higher than DECC's. Under this scenario, the de-rated margins fall to potentially concerning levels earlier – in the latter part of this decade rather than the 2020s.

3.24 The key points to take away from looking at the range of modelling we have undertaken is that (a) there is a credible risk of a capacity problem in the medium-term; however (b) the further into the future we try to assess future levels of capacity, the less certainty we have about the outcome.

Potential for other market reforms to improve security of supply

3.25 To judge whether a capacity mechanism is needed, it is necessary to consider whether there are other actions that might be able to give sufficient confidence that the capacity problem will not materialise.

3.26 New non-generation measures such as demand side response (DSR), storage and interconnection offer significant opportunities to improve security of supply and reduce the amount of generating capacity that is needed. In addition, reform of cash out, currently being considered by Ofgem, could help to improve security of supply.

3.27 However, our judgement is that it is not possible to say with confidence that these actions will improve security of supply to the extent that we can be confident that a capacity mechanism will not be needed.

[10] Published October 2011.
http://www.decc.gov.uk/en/content/cms/about/ec_social_res/analytic_projs/en_emis_projs/en_emis_projs.aspx

Conclusions about rationale for intervention

3.28 Based on the market failures, the credible risk of a capacity problem and the lack of certainty around the impact of other reforms to the energy market, there is a strong rationale for a capacity mechanism to reduce the risk of blackouts/brownouts occurring in a GB market with a much greater proportion of intermittent generation. This is the position that was set out in the White Paper.

4 Options Appraisal

4.1 We have analysed the three options for a Capacity Mechanism which are set out below:

i) **Business As Usual (BAU)**: The electricity market framework incorporates the other measures under Electricity Market Reform but does not include a capacity mechanism.

ii) **Strategic Reserve** (targeted mechanism): A small amount of capacity is procured and held outside the energy market, and only despatched when required.

iii) **Capacity Market** (market wide volume-setting mechanism): The total volume of capacity is set, and the required amount is procured from market participants, who participate in both the energy market and capacity market. Penalties are in place for providers of capacity who fail to deliver when required.

4.2 The two capacity mechanism options (Strategic Reserve and Capacity Market) have been assessed against the BAU*.*

4.3 If the decision were taken to adopt a Strategic Reserve or Capacity Market, the mechanism would be established through legislation and a delivery body enabled but capacity would only begin to be procured if and when they are deemed to be required, e.g. when a specified condition is met, and/or a central decision taker decides that an auction process should be initiated. If initiating the mechanism were not deemed necessary then these options would be equivalent to the BAU except that there would be greater institutional costs for the body monitoring the need to procure capacity through the mechanism. The costs and benefits of only procuring capacity once a problem is detected are discussed further in Section 6.

Option 1: Business As Usual

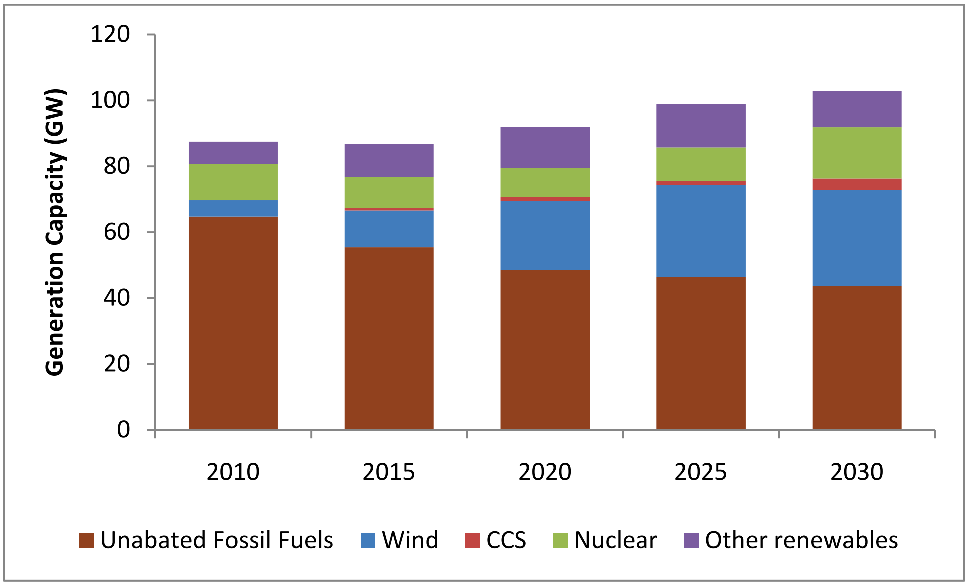
4.4 The BAU is the baseline against which we are comparing the options for a Capacity Mechanism. It assumes that a number of policy options that form part of the Electricity Market Reform package have been implemented, including the FiT CfD, Emissions Performance Standards and Carbon Price Floor. These will increase incentives for investment in low carbon capacity. It also assumes the Renewables Obligation (RO) is no longer available to renewable generators after 31^{st} March 2017.

4.5 A number of significant changes are expected to occur in this option even in absence of further policy interventions:

4.6 **Decarbonisation:** The BAU modelled in the latest energy system modelling runs assume that the power sector decarbonises so that the average plant emits at most 100g CO_2/KWh in 2030.[11] This entails a significant increase in intermittent and less flexible generation (predominantly wind and nuclear).

[11] This is the most conservative trajectory considered as part of the Carbon Plan (HMG - The Carbon Plan: Delivering our low carbon future, 2011), with the Committee on Climate Change (CCC) recommending decarbonising the power sector to 50g CO_2/kWh by 2030. The CCC paper can be found at: http://www.theccc.org.uk/carbon-budgets/4th-carbon-budget-path-to-2030.

Figure 5: Capacity by generation type



4.7 **Retirement of existing plant:** A substantial proportion of the UK's electricity generating capacity is expected to close over the next few years. Electricity generation capacity has a finite lifetime, and faces increasingly strict environmental regulation. Both these factors will lead to closures of some existing plant over the next decade. The Large Combustion Plants Directive (LCPD) will lead to closure of around 12 GW of coal and oil-fired fleet by 2016 at the latest. The Industrial Emissions Directive (IED) could also lead to further closures by 2023. In addition, according to current timetables, up to 7 GW of existing nuclear generating capacity which is reaching the end of its operational life will have closed by 2020 (assuming no lifetime extensions are granted)..

4.8 **Missing Money:** In setting out the rationale for a Capacity Mechanism, we have argued that there is potentially missing money, and that prices may not rise to the value of lost load. However, for the purposes of modelling of the BAU we have assumed a wholesale market where prices can rise to an value of lost load of £10,000/MWh when there is scarce capacity. In one sense, this assumes that the cash out process is reformed so as to make the cash out price in the balancing mechanism fully cost reflective. There are two reasons for this assumption: The first is that this is consistent with how we have modelled capacity mechanisms for Electricity Market Reform in the previous two impact assessments.[12] The second is that we do not have evidence to suggest what the 'correct' level of missing money is because we have never had long periods of high and peaky prices where investors could observe the Government or system operator's tolerance for high prices. The assumption that prices can rise to the value of lost load is a crucial assumption in the modelling and is a key driver of many of the quantitative results presented in Section 5. We recognise the lack of 'missing money' in the modelling of the BAU is a significant limitation and take account of this in the qualitative assessment of the options in Section 6.

Option 2: Strategic Reserve

4.9 A targeted mechanism involves:

- a central determination of the required reliability level and whether the market is likely to deliver this;

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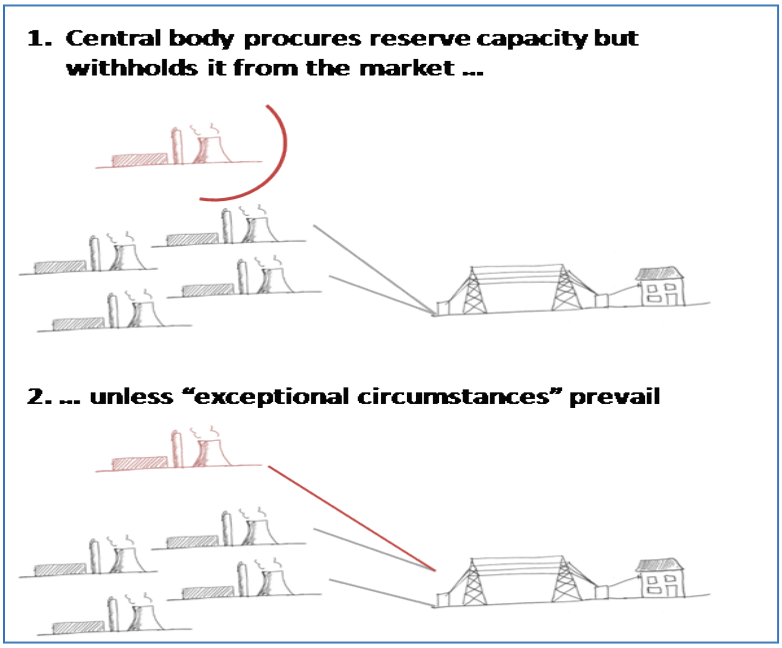
[12] Electricity Market Reform - options for ensuring electricity security of supply and promoting investment in low-carbon generation;

- December 2010: http://www.decc.gov.uk/assets/decc/Consultations/emr/1042-ia-electricity-market-reform.pdf
- June 2011: http://www.decc.gov.uk/assets/decc/11/policy-legislation/emr/2180-emr-impact-assessment.pdf

- if there is a shortfall, a central body would be charged with competitively procuring the necessary volume and mix of a Strategic Reserve; and
- the Strategic Reserve is then withheld from the electricity market and would only be despatched when prices rise above a certain level – the despatch price.

4.10 This is illustrated in the diagram below:

Figure 6: Strategic Reserve



4.11 A Strategic Reserve is assumed to be used as generator of last resort (i.e. before deploying voltage reductions and blackouts) and would be made available to the market through the balancing mechanism, priced at an estimate of the value of lost load (assumed for modelling purposes to be £10,000/MWh). As part of the Electricity Market Reform White Paper, we consulted on the possibility of despatching a strategic reserve at a lower 'economic' level than the value of lost load which would require a larger strategic reserve. Following further analysis, this option is no longer under consideration because of the danger that it would be likely to interfere with the current wholesale market and would be more likely to lead to the 'slippery slope' issue discussed in Section 6.

Option 3: Capacity Market

4.12 A Capacity Market involves:

- Government will take a decision, based on advice from the System Operator and possibly other technical experts (including Ofgem), on the volume of capacity to be contracted. This advice will form part of the delivery planning process described in the Technical Update. This should ideally be some years ahead of the year capacity needs to be in place ('the delivery year') in order to enable the construction of new capacity, though the gap between the auctions and delivery year for the first auction process could be shorter if necessary to get capacity in place earlier.

- Ministers will decide when to run the first auction process based on future estimates of security of supply and the potential for the market to bring forward adequate capacity without the introduction of the mechanism.

- Providers of capacity – including existing and new plants, and potentially non-generation technologies and approaches such as DSR – will be able to offer the quantity of reliable capacity they can provide in a delivery year into an auction run by the System Operator. All providers of capacity will be able to participate, potentially subject to some limitations on low carbon plant. This central auction process will allow a single central body to ensure adequate capacity will be available to meet demand.

- If successful in an auction, providers of capacity will receive revenue for providing reliable capacity. These payments will provide a steady income stream from the delivery year. Providers of capacity will also be subject to penalties to ensure the capacity they have contracted to provide is available when required.

- The costs of capacity will be shared among suppliers, so capacity contracts will ultimately be paid for by consumers.

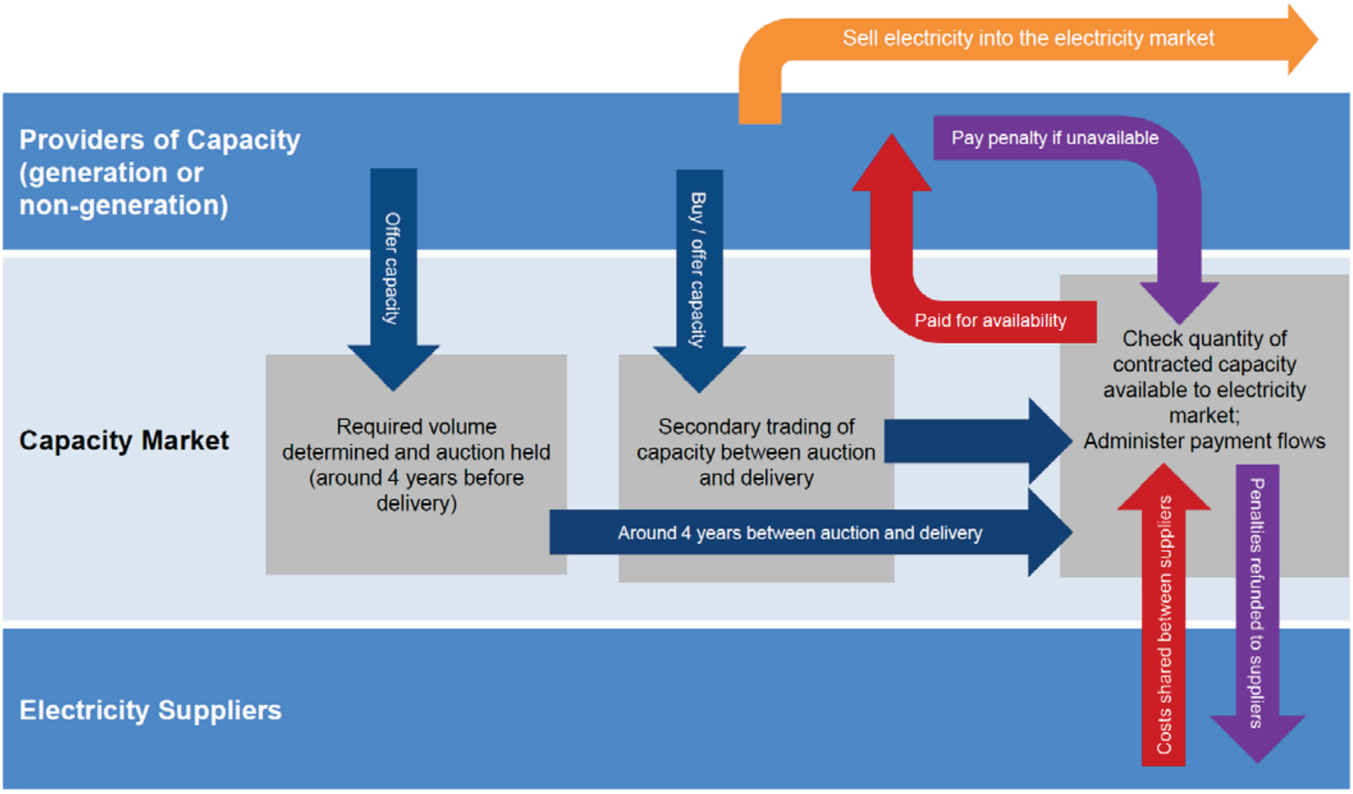
4.13 The White Paper discussed the option of the penalties for failing to deliver being purely market-based, in the form of 'Reliability Contracts'. We proposed to take a decision on the nature of penalties later, and this option remains under consideration, alongside other approaches. In order to conduct quantitative analysis for the Impact Assessment we have assumed the use of Reliability Contracts. The modelling approach is described in detail in annex A

4.14 The Reliability Contract places an obligation on the provider to make energy available (i.e. to be generating or available for despatch)[13] when the 'strike price' in a reference market is reached or, if not available (i.e. not generating or available to despatch), to compensate the delivery body for the cost of the missing energy by paying the difference between the strike price and the price in the reference market (e.g. cash out). This places an incentive on parties to ensure capacity is available at times of scarcity (defined by the market price and strike price) and effectively places a price cap in the energy market at the level of the strike price. The level of the strike price is important in the quantitative analysis as this has a direct impact on the level of capacity payment since it caps revenues from the energy market for all participants. The level of the strike price for reliability contracts in the modelling has been set at £500/MWh.

4.15 How a Capacity Market works is illustrated in the diagram below:

[13] For DSR, this could mean a demonstration that load has been reduced or is available to be reduced.

Figure 7: How a capacity market works



4.16 This diagram also illustrates the financial flows involved in a Capacity Market. Capacity providers who have bid successfully into the Capacity Market would receive payment from the delivery year. The cost of the capacity procured through the auction process would be passed on to suppliers and ultimately on to consumers. However consumers will also benefit from lower electricity prices due to the increase in capacity and, as assumed for the purposes of the Impact Assessment, from capacity providers having to reimburse consumers when not available at times when short-term market prices exceed the strike price set out in the reliability contract (effectively placing a price cap in the energy market). This benefit to consumers should largely offset the additional cost to consumers from procuring capacity through the capacity market. The net effect of the Capacity Market is discussed further in the quantitative modelling and in the qualitative assessment.

4.17 A Capacity Market is different to National Grid's Short Term Operating Reserve (STOR) service. STOR is procuring a level of flexible reserve for real time plant failures (including wind forecast errors) and demand forecast errors beyond gate closure. STOR does not provide a guarantee that there will be sufficient capacity, indeed the system operator will take action to reduce demand (e.g. via voltage reduction) in order to ensure it has sufficient reserve. This reserve is important to ensure there is sufficient flexibility to meet real time demand, the alternative would be the risk of the loss of the entire system. A Capacity Market increases the probability that there will be sufficient generation to meet demand at all times; however a level of reserve is still required above this.

How the options have been assessed

4.18 The options for a capacity mechanism are appraised based on both qualitative and quantitative analysis. The quantitative analysis shows that the net impacts of a Capacity Market are slightly worse than those of a Strategic Reserve (though a Capacity Market is better for consumers). However the quantitative estimates do not take into account a number of significant factors that shape overall assessment (as is explained further in Section 5). The qualitative assessment, looking at those wider impacts provides a more robust and comprehensive assessment of the options. This shows that the Capacity Market has greater benefits in terms of achieving security of supply and is potentially more cost-effective though it does have significant policy risk.

5 Quantitative options assessment

5.1 The value for money assessment of the two capacity mechanism options have been assessed quantitatively in the following ways:

i) Energy system impact
ii) Institutional impacts
iii) Impacts on businesses

5.2 In addition to the value for money assessment, we have quantified the potential impacts of a mechanism on security of supply and on energy bills.

Energy system modelling

5.3 All mechanisms should have similar (and relatively small) net costs if implemented effectively and if the market operates efficiently. While the Capacity Market involves greater levels of payment to generators than a Strategic Reserve, consumers should be equivalently compensated by the lower prices in the wholesale electricity market. The benefits of each mechanism depends on the extent to which it reduces lost load and the value that consumers place on lost load. Essentially, the mechanism involves a small net cost to purchase an ‘insurance policy’ against voltage reductions and blackouts.

5.4 Energy system modelling of the electricity market provides a view of the costs and benefits of different types of capacity mechanism, although there are significant caveats associated with the results. The modelling shows a net cost of between £1.1 and £2.5bn over the period 2010 – 2030[14] compared to the BAU. The table below shows the net present value of the benefits of the options and how this breaks down into various components. **However, it is important to note that the net cost of the policies detailed below is largely a product of the modelling and in reality may not be representative of the costs of either of the design options.**

Figure 8: Energy system costs and benefits

Energy System Costs and Benefits £m (Real 2009)	**Strategic Reserve**	**Capacity Market**
Carbon costs	22	-285
Generation costs	384	775
Capital costs	911	2256
Total Costs	**1316**	**2746**
Total Benefits (Reduction in unserved energy)	**220**	**269**
Change in Consumer Surplus	-1097	3077
Change in Producer Surplus	0	-5547
Change in Net Welfare	**-1096**	**-2477**

[14] These costs have been discounted to present values. Note that all costs occur between 2024 and 2030 because that is when a Capacity Mechanism would be triggered under the central scenario.

5.5 The costs modelled include the capital costs of the additional capacity incentivised by the capacity mechanism, as well as the fuel and carbon costs associated with the additional capacity. The security of supply benefits modelled are reductions in unserved energy, valued at £10,000/MWh. The benefits are very similar for both options and are largely driven by the security of supply standard assumed (10 per cent de-rated capacity margins).This is mostly from reductions in *involuntary* energy unserved – i.e. lower blackouts and forced voltage reductions. However it also includes some benefits from the reduced need for voluntary unserved energy.

5.6 The result that both mechanisms have net costs in the modelling is driven by **two key** assumptions, namely that:

- there are no market failures in the electricity market in the BAU scenario. Modelling of the BAU does not take into account the likelihood of 'missing money', i.e. the risk that Government/the regulator will intervene if prices rise regularly to the value of lost load (assumed to be £10,000/MWh in the modelling). This means that the energy-only market in the BAU modelling delivers a de-rated capacity margin that trends towards the optimal level from a security of supply perspective; and
- in the scenarios with a capacity mechanism, a level of de-rated capacity (10 per cent) is imposed which is higher than that in the BAU (around 5%).

5.7 These two assumptions mean that any scenario which included a capacity mechanism would necessarily show a negative NPV. In practice, the introduction of a capacity mechanism could have a significant net benefit. This is because we believe that there are market failures in the current electricity market (for example missing money) and these market failures could lead to a suboptimal level of capacity without the introduction of a capacity mechanism. The introduction of a capacity mechanism that raised capacity towards the optimal level could therefore have a net benefit since the security of supply benefits would outweigh the costs of the additional capacity. **As such, we do not believe that the net costs in Figure 8 are representative of the likely impact of implementing either a Capacity Market or a Strategic Reserve.**[15]

5.8 The result in the modelling that a Capacity Market has a lower NPV than a Strategic Reserve is due to differences in how plants behave in relation to the Industrial Emissions Directive (IED)[16]. In the modelling of a Capacity Market, coal plants retire early as they do not expect price spikes in the early 2020s and need to be replaced by additional gas plants. The extent of the difference in behaviour modelled is a result of the assumption that market participants have foresight of market outcomes until 2030. The coal plants simulated foresee wide capacity margins and little scarcity rents and therefore choose another option under the IED which means that they must close by 2023. However in reality plants may not have this level of foresight and so, while some plants may take the decision to retire early, we do not expect all affected plants to change their behaviour as a result of the form of a capacity mechanism. **The modelling results for the two options are therefore not necessarily demonstrative of the likely difference in costs between the two types of mechanism.** We attempt to capture the likely difference in impacts between options as part of the Qualitative Assessment in Section 7.

[15] As set out above, the uncertainty in the modelling is around consumers' real value of lost load; the level of missing money in a future energy-only market; and the level of reliability that would be desired by the body charged with deciding on the capacity margin.

[16] Under the IED coal plants must run low in the near term if they wish to stay open and run as peaking plant in the 2020s. For further detail on the IED see: http://ec.europa.eu/environment/air/pollutants/stationary/ied/legislation.htm

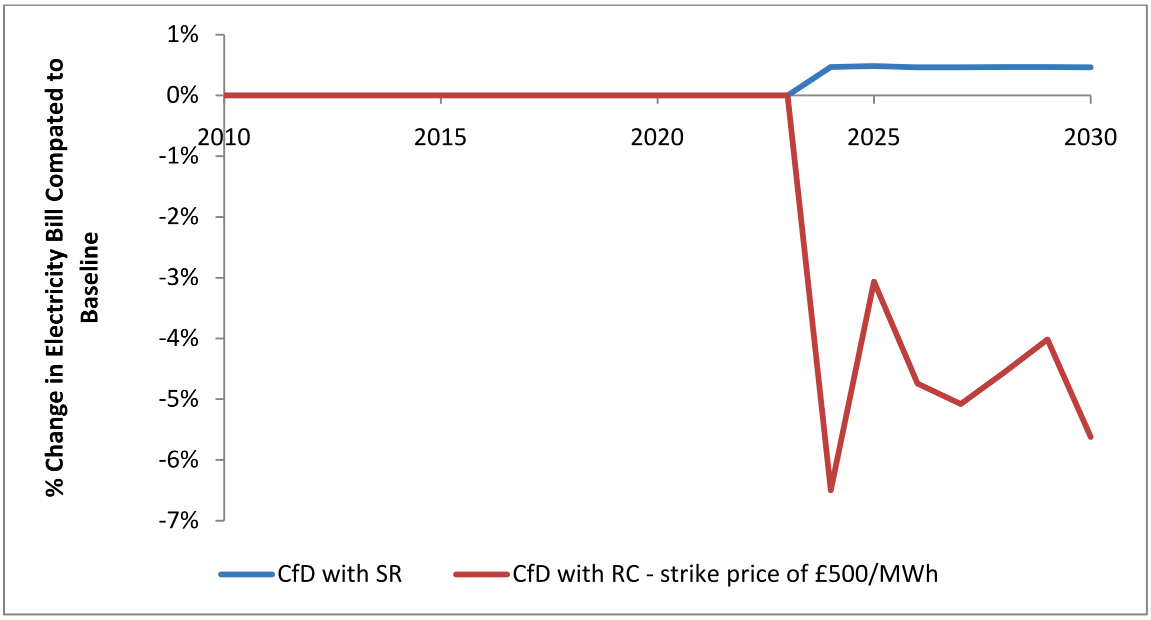
5.9 The costs and benefits are broken down into more detail in figure 8. For a Strategic Reserve we see an increase in capital costs and generation costs as a result of the additional capacity in the Strategic Reserve required to meet the de-rated target of ten per cent. We also see a small increase in carbon emissions associated with the additional capacity. There are some benefits in terms of a reduction of lost load. Note that the costs outweigh the benefits for the reason set out in paragraph 5.6. For a Capacity Market, capacity and generation costs have increased compared to the Strategic Reserve. This is because coal plants that have retired as a result of the change in IED decision must be replaced. This new capacity is cleaner than the coal that has retired which is why there is a carbon benefit associated with a Capacity Market. Energy Unserved is very similar to the case of a Strategic Reserve, because both forms of mechanism result in a ten per cent de-rated margin.

Distributional impacts

5.10 The distributional impacts of the two mechanism options are very different in the modelling. With a Strategic Reserve, the additional costs of capacity are very clearly borne by consumers. With a Capacity Market, the change in the structure of the market can have large distributional impacts which outweigh the costs of additional capacity: because energy market prices have effectively been capped through a Reliability Contract (for the Impact Assessment we have assumed the use of market based penalties), the large scarcity rents that accrue to generators in an energy-only market are removed and the rents that generators receive in the new Capacity Market are not as large as the rents they no longer receive.

5.11 We have modelled the bill impacts of the different mechanisms in the central scenario. The energy system modelling suggests that the impact on the average annual electricity bill over the period 2010 – 2030 would be between a £1 increase (for a Strategic Reserve) or an £11 reduction (for a Capacity Market) compared to an average annual bill of £612 without a Capacity Mechanism. The impact would be larger when looking at the years in which the mechanism is in operation, i.e. over the period 2024 – 2030. In this period, the impact is for an average £3 increase (for a Strategic Reserve) or a £33 decrease (for a Capacity Market) on an average annual bill of £679 without a Capacity Mechanism. The reason for this decrease in the modelling is because a Reliability Market, limits the scope for generators to receive scarcity rents. However, for the reasons stated already, these figures are to be treated with caution, and impacts could be higher as a result of inefficient design resulting in overpayment for capacity or an inaccurate prediction of the capacity requirement resulting in unnecessary over-procurement.

Figure 9: Change in Consumer Electricity Bills from a capacity mechanism



5.12 In addition to reducing consumer bills, a Capacity Market can reduce the volatility in consumer bills: In an energy only market which relies on scarcity rents to produce the investment signal, this scarcity pricing could have a significant impact on the volatility of consumer bills. The modelling suggests that the average annual domestic consumer bill increases by 12 per cent from 2023 to 2024 as a result of scarce generation capacity in the central scenario. A Capacity Market acts to reduce this volatility. With a Capacity Market, the increase in consumer bills in that same year is 4 per cent. While the exact numbers are difficult to forecast, the principle is clear, that a Capacity Market which provides a more stable investment signal is more likely to reduce the volatility of bills than an energy only market which relies on scarcity rents to pay for the fixed costs of investment.

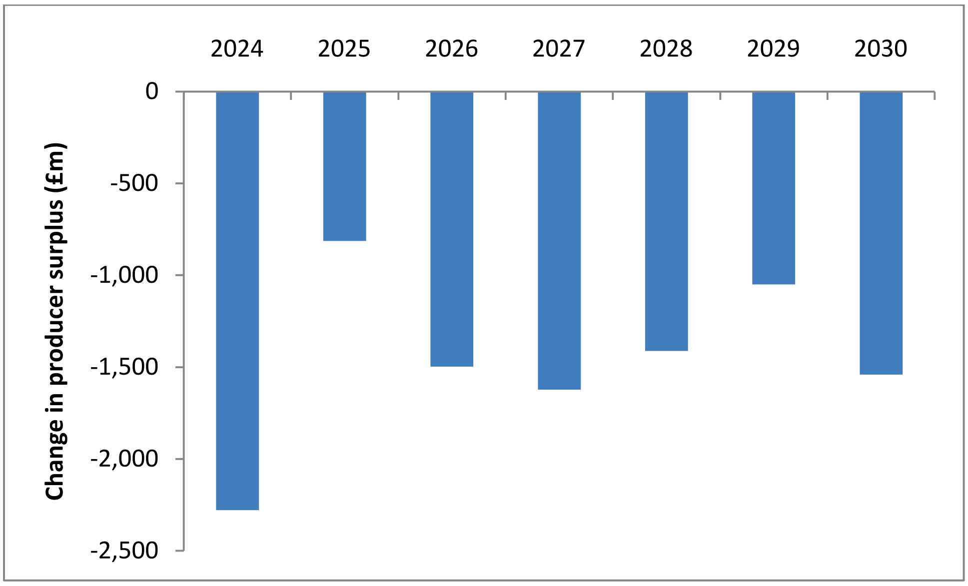
5.13 The following table shows the impact of a capacity mechanism on the bills of different groups – domestic consumers, businesses and energy intensive industries (EIIs).

Figure 10: Bill Impacts

	Typical bill for the Business As Usual	Change in Typical bill %	
		Strategic reserve	Capacity Market
Domestic, (£)			
2011-2015	574	0.0%	0.0%
2016-2020	574	0.0%	0.0%
2021-2025	607	0.2%	-2.0%
2026-2030	693	0.5%	-4.8%
Non Domestic, (£000)			
2011-2015	1299	0.0%	0.0%
2016-2020	1464	0.0%	0.0%
2021-2025	1662	0.2%	-1.2%
2026-2030	1743	0.5%	-2.8%
Energy Intensive Industry, (£000)			
2011-2015	10310	0.0%	0.0%
2016-2020	11859	0.0%	0.0%
2021-2025	13730	0.3%	-1.0%
2026-2030	14415	0.6%	-2.3%

5.14 As well as the impact on consumers of electricity, in the case of a Capacity Market, there is also an impact on the generation companies which produce electricity. Figure 8: showed the present value of the producer surplus that results from the introduction of a Capacity Market. The producer surplus is the additional money received by producers above the minimum price that they would have been willing to produce electricity for. In an energy only market which is experiencing scarcity, this surplus is likely to be high because wholesale prices are rising to the value of lost load and all generators are assumed to be receiving those prices at those times. In a Capacity Market, there are now two markets, an Energy Market and a Capacity Market. The producer surplus in these two markets determines total producer surplus. The modelling suggests that the producer surplus is likely to be lower under a Capacity Market than under an energy only market. This is because the Capacity Market avoids scarcity rents and the result is shown in the chart below.

Figure 11: Reduction in producer surplus as a result of a Capacity Mechanism



5.15 Under a Capacity Market both consumer bills and producer profits are lower than in the BAU. It is important to understand some of the limitations around these conclusions:

i) It assumes that in an energy only market, the relationship between capacity scarcity and the wholesale market mark up on short run marginal costs follows the historic relationship which is embedded within the assumptions that underpin the Redpoint model. However, the data which informs this relationship is mostly based on periods where we have not experienced the sorts of capacity margin which is appears in the forecasts. There is limited evidence around this relationship at lower capacity margins and therefore there is uncertainty around what wholesale prices would look like at these low capacity margins.

ii) A second limitation is that the modelling assumes that the Capacity Market operates perfectly and that there would be no gaming in any capacity auction process. Market power in a Capacity Market would drive up the producer surplus in this market. This would also have an effect on bills.

Size of capacity revenues

5.16 The choice of mechanism has an impact on how capacity is paid for. Under a Capacity Market, all capacity receives revenues through a capacity market separate from the electricity wholesale market. Under a Strategic Reserve, most capacity continues to be paid through the wholesale market, with only the additional capacity in the reserve paid for via the Strategic Reserve. The table below shows the gross capacity cost associated with the different mechanisms.

Figure 12: Gross capacity revenues thrugh the mechanisms, £m

	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Strategic Reserve	0	0	0	0	326	326	326	326	326	326	326
Capacity Market	0	0	0	0	2131	1798	1911	1780	1634	1686	1806

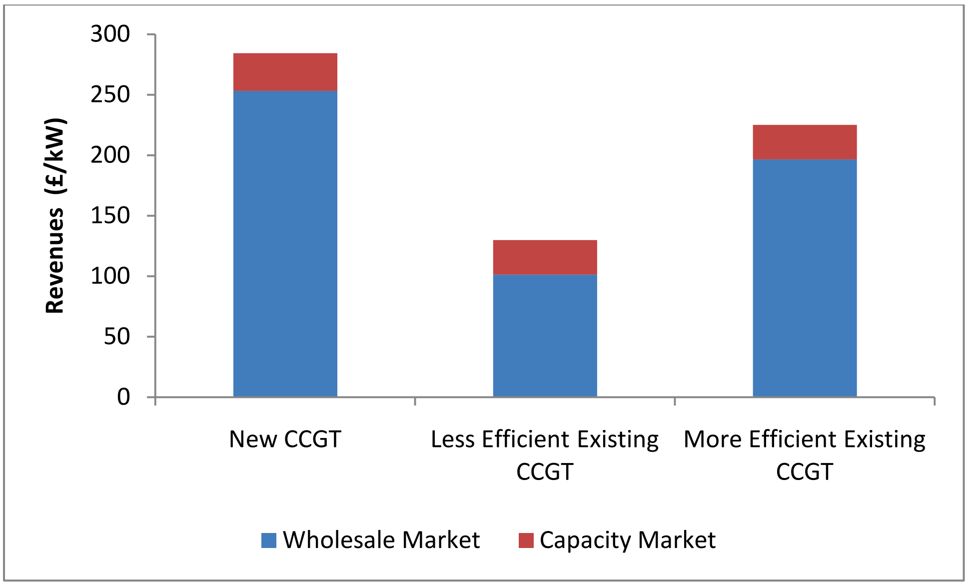
5.17 Under a Capacity Market the gross capacity revenues that go to providers of capacity are modelled to be around £1.5-£2.5 billion per annum. The gross cost of revenues flowing to generators in a Capacity Market would be offset by lower wholesale prices (resulting from more capacity on the system) and, as assumed for the purposes of the Impact Assessment, from capacity providers having to reimburse consumers when not available at times when short-term market prices exceed the strike price set out in the reliability contract (effectively placing a price cap in the energy market). Taking this into account, the 'net' cost of the additional capacity under a Capacity Market would be around £300-350 million per annum, which is the same as under a Strategic Reserve.

Impact on plant economics

5.18 A capacity mechanism changes the way generation plant receives revenues. For a Strategic Reserve, this change is minor. Plant that is outside the Strategic Reserve is remunerated as now via an energy only market. Plant inside the reserve strikes a specific contract with the operator of the reserve which would presumably cover both the capacity and fixed costs of generation as well as the variable costs

5.19 A Capacity Market on the other hand changes the way that plant is remunerated. Now plant receive two revenue streams, one from a Capacity Market and one from an Energy Market. Our modelling provides an estimate of what the revenues might be for certain types of Combined Cycle Gas Turbine (CCGT) plant. The chart below shows the revenues received by new plant, and from two different types of existing plant. The average load factor for a less efficient plant is 11% while the more efficient plant has an average load factor of 23%. As can be seen, the capacity payment becomes an increasingly important component of a plant's revenues as it is used less often. For a less efficient plant, the capacity payment represents around 22%, whereas for a more efficient plant it represents around 13% of revenues

Figure 13: Average Annual Revenues Received by a CCGT plant 2024 – 2030 in the central scenario



Administrative costs to Business

5.20 An administrative burden is the cost to business of the administrative activities that it is required to conduct as a result of a policy.

5.21 It is not thought that a Strategic Reserve would impose any administrative burden because it would be centrally organised.

5.22 However, a Capacity Market would have an additional impact because there would be a new market for generating companies to participate in. Following the methodology set out in the Electricity Market Reform White Paper Impact Assessment[17] the administrative burden of a Capacity Market is estimated as between £4m and £24m per year.

5.23 This is based on the formula: Activity Cost = (wage x time) x (population x frequency). For a Capacity Market it is modelled that capacity auctions will be held annually and each company participating in the auction process will require one or two members of full time staff, costing around £50,000 each. The number of businesses affected (i.e. the population) is estimated to be between 80 and 239.[18]

5.24 In the central case we have assumed the mid-way point in the estimated cost range (i.e. £14m per year) to be the best estimate of the administrative burden of a Capacity Market. It is expected that businesses would incur this cost from the point that the central deliverer decides to initiate a Capacity Market. In the central scenario this is in 2019, five years before capacity is forecast to be needed, one additional member of full time staff is employed which results in a total discounted cost of £97m. In the high cost scenario capacity is also needed from 2019 and two staff are required – with a total discounted cost of £167.

Institutional costs

5.25 The institutional costs associated with delivering a Capacity Market are estimated to be around £5m to set up (to cover one off costs such as IT systems) and £4m per year to run (recruitment, building preparation, implementation, facilities, and maintaining IT systems).

5.26 The institutional costs associated with delivering a Strategic Reserve are estimated to be around £1m to set up (to cover one off costs such as IT systems) and £2.2m per year to run (recruitment, building preparation, implementation, facilities, and maintaining IT systems).

5.27 There are a number of uncertainties surrounding the costs and we are continuing work to develop them with prospective delivery partners as part of the business case process for Electricity Market Reform delivery.

5.28 We recognise in particular that the institutional costs assumed a separate institution was set up to deliver the capacity mechanism. However given that a Capacity Market can be delivered by the body tasked with delivering the CfD, and given that many of the costs will have already been incurred setting up the CfD delivery body, the institutional costs estimated in this IA may be an overestimate.

Transitional Arrangements

5.29 Once the decision is taken to adopt a Strategic Reserve or Capacity Market, the mechanism would be established through legislation and a delivery body enabled but capacity would only begin to be procured if and when they are deemed to be required, e.g. when a specified condition is met, and/or a central decision taker decides that auctions should be initiated.

5.30 In the central and high cost cases it is assumed that:

[17] Paragraph 376; http://www.decc.gov.uk/assets/decc/11/policy-legislation/emr/2180-emr-impact-assessment.pdf
[18] The lower figure comes from 5.11 in DUKES and is the number of major power producers. The upper figure represents the current number of Balancing and Settlement Code parties.

- business will bear the admin costs of a Capacity Market from once the mechanism begins to procure capacity – i.e. five years before the additional capacity becomes available (2019 in the central and high case);

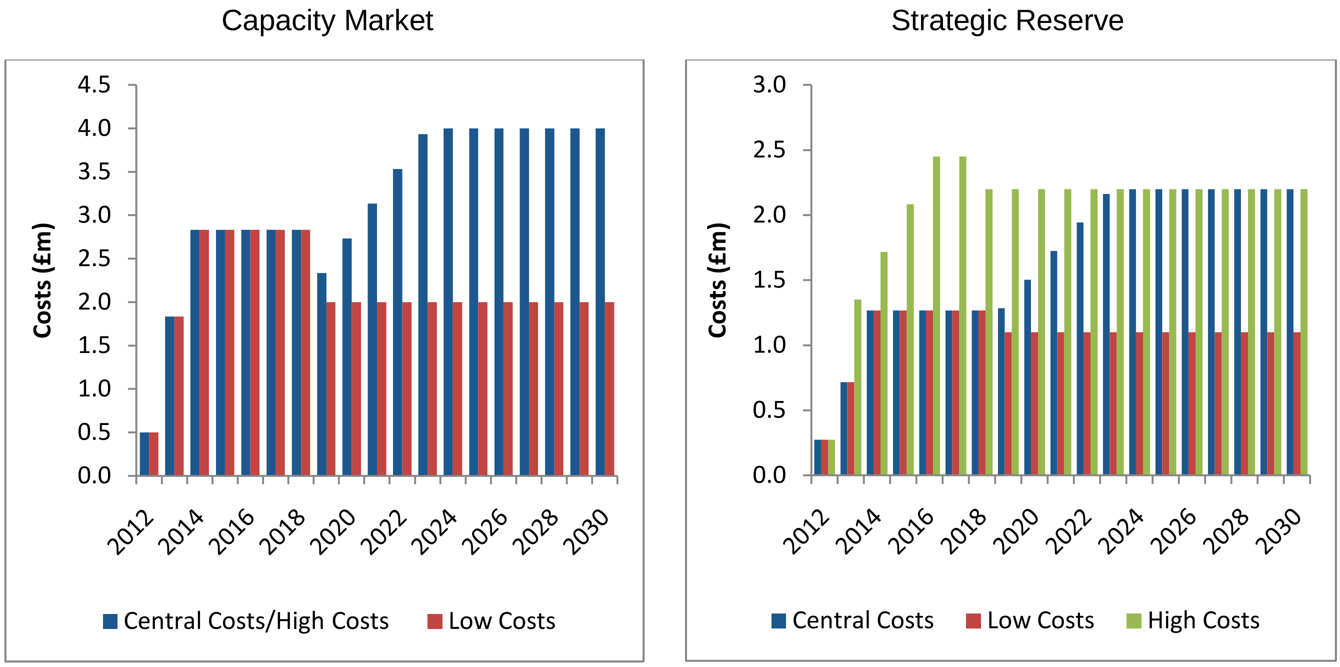
- until a mechanism is initiated (2012-2018 in the central case) the set-up and half the running costs will be incurred (ramping up from 2012 to 2014). These annual institutional costs will cover the initial development, implementation costs and then maintaining processes and systems that are ready to run;

- once the mechanism is initiated and new capacity is being procured (2019-2030) the running costs will increase to the full amount.

5.31 In the low cost case it is assumed that the capacity mechanism is not needed but the assessment of the need for a capacity mechanism will continue with half the annual running costs in the central case.

5.32 Based on this approach, the discounted lifetime institutional costs for a Capacity Market are £39m in the central and high cost cases and £27m in the low cost case. For a Strategic reserve these are £20m in the central case, £14m in the low cost case, and £25m in the high cost case. The annual costs for each scenario are illustrated in Figure 14: below.

Figure 14: Capacity mechanism institutional costs, £m



Net Present Value assessment

5.33 Including the institutional costs and administrative burden costs on to the energy system impacts does not have a significant effect on the overall assessment: A Strategic Reserve still has a better NPV than a Capacity Market, although clearly this is still subject to the significant caveats mentioned above around the energy system modelling. However it does affect the cost of tasking a delivery body to run a Capacity Market if no problem is detected and there is no capacity auction process held. This is explored further in the sensitivity analysis.

Net Present Value of a Capacity Mechanism £m (Real 2009)	**Strategic Reserve**	**Capacity Market**
Energy system costs	1316	2746
Institutional costs	20	39
Administrative costs to business	0	97
Total Costs	**1336**	**2882**
Total Benefits (energy system)	**220**	**269**
Change in Net Welfare	**-1116**	**-2613**

Sensitivity Analysis

5.34 The central estimates around NPV make a number of assumptions about extent and timing of costs incurred through a capacity mechanism. Sensitivity analysis helps illustrate the impact a capacity mechanism under alternative plausible assumptions.

5.35 In the central case we have used the central modelling run, with a capacity mechanism being initiated in 2019 and additional capacity being procured from 2024. Businesses incur administrative burden costs once the mechanism has been triggered from 2019. Institutional costs are born gradually as the institutional capacity to initiate and deliver a capacity auction process is developed.

5.36 Two further scenarios are used to illustrate the possible net benefits of a Strategic Reserve. One is the 'No problem' scenario where the mechanism is never used to procure additional capacity. The other is the 'Stress Test' scenario which assumes a greater security of supply problem.

5.37 In the 'No Problem' scenario we have assumed that the energy-only market does deliver sufficient capacity and that capacity scarcity conditions do not occur. This means for a Strategic Reserve that capacity is never procured or for a Capacity Market that a capacity auction process is never run.

5.38 If the capacity mechanism is never initiated there is still some institutional cost associated with ensuring that a deliverer is tasked and has the capability to deliver an auction process if and when required. These costs are £5 million setup costs and £2 million annual running costs for a Capacity Market or £2 million setup and £1 million running costs for a Strategic Reserve. These costs include, for example, the development of IT systems and keeping processes up to date. It is assumed though that the capacity mechanisms would create no additional administrative burden for businesses if the mechanism were not initiated.

5.39 In the 'Stress Test' scenario, we have assumed that the capacity mechanism is introduced in a scenario which has larger security of supply risks. In this scenario the capacity mechanism is run at the earliest opportunity (likely to be 2015) to provide additional capacity by 2016. This leads to the full institutional set-up costs and running costs being incurred earlier than in the central case.

5.40 The assumptions around the different scenarios are summarised in Figure 15:

Figure 15: Scenarios for sensitivity analysis

No Problem Scenario	Central Scenario	Stress Test Scenario
No security of supply problem emerges. Only half the institutional costs are incurred as the mechanism is never initiated. There are no administrative costs placed on business.	Central DECC assumptions used in energy system modelling. Mechanism is initiated in 2019 to procure capacity from 2024. Central administrative costs on business incurred from 2019.	Stress test modelling used, assumes £5000/MWh price cap, two year delay on first new nuclear build and National Grid demand estimates. Mechanism is initiated early to deliver additional capacity from 2016. High administrative costs on business from 2013.

5.41 The net cost of a Capacity Market is lower under the Stress Test than in the central scenario. This is for two reasons: Firstly that there is a price cap in the modelling which means that prices cannot rise above £5000/MWh. This missing money means that there are positive marginal benefits of increasing capacity above the level delivered in the BAU. Second is that the closure of coal plant under the IED which takes place under the central scenario, now no longer takes place.

5.42 As a result of this the 'high cost' scenario for a Capacity Market uses the energy system modelling from the central case, with new capacity coming on from 2019. Institutional costs are also consequently the same as in the central case. However the high cost estimates incorporate the higher estimates of business administration costs (£167m lifetime discounted value).

5.43 The results of the sensitivity analysis are shown below.

NPV Sensitivity Analysis of a Capacity Mechanism £m (Real 2009)	Strategic Reserve	Capacity Market
Central Scenario	-1116	-2613
Low Cost Scenario	-14	-27
High Cost Scenario	-2734	-2683

Conclusions from quantitative modelling

5.44 As discussed, there are very significant caveats around the energy system modelling of the different options, particularly related to the assumption in the modelling that the energy market works perfectly efficiently and all participants have perfect certainty about the future.

5.45 The quantitative modelling therefore tells us that if we think that there are no problems of 'missing money' or gaming in the energy market then any capacity mechanism (even if never deployed) will have a net negative impact on society, although a Capacity Market has some benefits in reducing the volatility of bill impacts (i.e. acting as an insurance policy against future price spikes). It also tells us that the cost of a Capacity Market is mainly borne by generators rather than consumers and that a Capacity Market actually has the potential to reduce consumer electricity bills.

5.46 However, as set out in Section 4, there is reason to think that an energy-only market will not deliver the efficient outcome and therefore that a capacity mechanism will have a positive NPV if it can deal with the underlying market failures in a cost-effective way. A capacity mechanism is then acting as an insurance policy against price spikes and blackouts due to market efficiencies (as well as, in the case of a Capacity Market, against the price spikes that would be created by an efficient market).

5.47 To assess which option best delivers this it is necessary to look qualitatively at the costs and benefits of the different options under more realistic assumptions, such as that generators are concerned about regulatory intervention if prices rise too high and that market participants may lobby a complex system or withhold supply to drive prices above the efficient level (i.e. gaming). This assessment is set out in the following Section.

6 Qualitative options assessment

6.1 As explained above there are very significant caveats around the energy system modelling of a Strategic Reserve and Capacity Market. In practice the costs and benefits of the various options are likely to differ due to a number of factors not captured by the economic modelling. The quantitative assessment has limited value in indicating which option should be the preferred approach. We are therefore using the criteria shown in the table below to qualitatively assess the different options. We have scored the options using green, amber and red arrows as per the assessment criteria specified in the table.

6.2 The criteria have been split into the benefits, costs and risks of each option, with overall assessments given for each category. The overall assessments reflect an implicit judgement about the weighting of each criteria and is explained in the text for each overall assessment.

6.3 The options are considered using the qualitative criteria against the baseline (BAU).

Qualitative Criteria	Assessment	Scoring
Benefits		
B1. Ensuring Security of Supply	Does option provide enough reliable capacity to ensure security of supply?	Green Arrow = enough reliable capacity to meet demand; Red Arrow = insufficient to meet demand
B2. Robust against market power – energy market	How big are the benefits in reducing gaming in the capacity market?	Green Arrow = No opportunities to game market; Red Arrow = No reduction in gaming
B3. Supports non-generation approaches (including DSR, storage, interconnection)	How does option affect ability of non-generation to address security of supply problem?	Green Arrow = DSR etc can play effective role; Red Arrow = option reduces role for DSR etc
Costs		
C1. Cost, practicality, and feasibility of implementation	How costly is mechanism to administer? How susceptible is it to being lobbied?	Green Arrow = simple mechanism to administer; Red Arrow = complex / bureaucratic to administer
C2. Robust against market power – capacity market	How significant are the opportunities for gaming the new capacity market?	Green Arrow = No gaming of capacity market; Red Arrow: Significant overpayment due to gaming
C3. Efficient determination of parameters	How many parameters need to be estimated centrally? How complicated is it to set the right level of capacity volume /price?	Green Arrow = minimum uncertainty setting parameters; Red Arrow = significant uncertainty setting parameters
C4. Market efficiency: Other (including reduction in barriers to entry; efficiency of despatch incentives)	Does option raise barriers to entry? Does option make efficient use of capacity?	Green arrow = no inefficient use of capacity, no negative impact on competition; Red Arrow = inefficiency in capacity use, new entry barriers
C5. Compatible with low carbon support measures (RO and FiT CfD)	Will option lead to overpayment of RO and FiT CfD plant? Can option align incentives for plant to be available when needed?	Green arrow = can align incentives for low carbon plant without overpayment: Red arrow = over-payment of low carbon plant;
Risk		
R1. Fit with GB market (includes vertical integration and bilateral contracting)	Will option work within GB market? How great is the risk of unintended consequences?	Green arrow = option can work well in GB market; Red arrow = hard to make option work well in GB
R2. Decarbonisation	Will option have an effect on emissions?	Green arrow = reduction in CO_2; Red arrow = increase in CO_2
R3. Adaptability	Is option adaptable once implemented? How difficult is it to exit from the mechanism?	Green arrow =option is adaptable and possible to exit; Red arrow = option is not adaptable and very difficult to exit

Qualitative benefits appraisal

6.4 **B1. Ensuring Security of Supply:** Delivering the desired level of reliability, at efficient cost, is a key consideration for any capacity mechanism. This is not sufficiently captured in the energy system modelling as it assumes that there are no underlying market failures in an energy-only market.

6.5 A Capacity Market is most likely to ensure that there is sufficient reliable capacity to meet demand because it involves specifying the required volume of capacity, and procuring that amount. If Reliability Options are used, it also addresses the underlying market failure of 'missing money' resulting from investor perception that Government will not allow spiky prices (as the mechanism effectively caps revenues for generators and limits gaming opportunities above the strike price so there will be less risk of state intervention during periods of high prices.

6.6 A Strategic Reserve is fairly likely to deliver the desired level of security of supply by keeping additional capacity in case of shortages. However there is greater risk to this option being effective. This is because a Strategic Reserve runs the risk of plants not selected for the Reserve choosing to close down if they do not receive a Strategic Reserve contract. If this happens this could lead to the 'slippery slope' effect, whereby more and more plant must form part of the Reserve to ensure it remains effective. This is undesirable in itself and, if it occurred rapidly, may mean that insufficient capacity is in place to deliver the required level of security of supply.

6.7 **B2. Robust against market power – energy market:** In markets with tight capacity margins, there is greater scope for gaming and market power – where generators withhold supply in order to force prices up in the short-term wholesale market. Capacity mechanisms that have a smoothing effect on prices can reduce opportunities for gaming in the energy market. This is because generators do not gain from driving the wholesale price above the level at which capacity is called upon. This benefit is not reflected in the energy system modelling as it is assumed that there are no gaming opportunities.

6.8 A Capacity Market has the potential to be most effective at reducing gaming opportunities in the energy market, although the extent to which it succeeds in eliminating gaming opportunities depends on how the penalty incentive is designed. A Strategic Reserve is unlikely to have benefits in reducing gaming as it is only despatched at as generator of last resort (when prices have already risen to the value of lost load – around £10,000/MWh), meaning that there is still scope for significant price spikes in the energy market. Despatching at a lower price would reduce gaming opportunities but would lead to a much larger reserve.

6.9 The benefits around reducing gaming in the energy market assume that the incentives for strategic behaviour might increase in the future due to tighter capacity margins, increasing shares of intermittent generation and reforms of the balancing market that allow prices to rise to the value of lost load. If there were no danger of strategic behaviour in absence of an intervention, then none of the options would deliver benefits.

6.10 **B3. Supports non-generation approaches:** It is desirable that a capacity mechanism provides incentives for non-generation approaches – e.g. DSR, interconnection and storage – to play a role in balancing supply with demand where cost-effective. A capacity mechanism may incentivise non-generation approaches if these technologies are eligible for payments, but may also disincentivise non-generation approaches if the mechanism dulls the price incentives that would occur in an energy-only market. If non-generation options are eligible to participate in the mechanism then the net effect is likely to be a benefit because the overall effect of the mechanism is to increase capacity.

6.11 DSR should be able to participate directly in a Capacity Market, although this depends on detailed mechanism design, in particular in relation to the requirements which are placed on DSR in the procurement process, and to resolving the baseline against which DSR is measured within a Capacity Market.

6.12 It is unlikely that DSR would participate directly in the Strategic Reserve as it is unlikely to be the least-cost way of providing reserve (as in practice DSR providers are likely to reduce usage before prices have reached the level at which the Strategic Reserve is used). However there will still be incentive for DSR to participate in the energy market given the likelihood of prices spiking at high levels for short periods (though these do not provide additional revenue certainty for DSR providers).

6.13 A Capacity Market could impact on the role for storage as it would reduce volatility in prices and associated arbitrage opportunities for storage providers. Storage may be able to bid into capacity auctions but may not be the most cost-effective way of providing capacity.

6.14 With regard to interconnection – the handling of interconnected capacity (outside GB) in a Capacity Market is uncertain. This is a complex issue and will require further careful consideration to ensure that we maximise the potential for interconnected capacity to provide security of supply, but do not pay overseas generators to provide capacity without increasing their incentives and ability to do so.

6.15 **Overall Benefit Assessment:** A Capacity Market is most likely to ensure that sufficient reliable capacity is built as it procures capacity directly and as it ensures generators have optimal incentives to generate at times of scarcity. A Strategic Reserve has more limited benefits as it does not reduce opportunities for gaming and it does not eliminate the risk of capacity shortage given the possibility of the slippery slope. However the overall size of the benefits depends on the assessment of the security of supply problem: If it is thought that an energy-only market would deliver security of supply then the benefits of all the capacity mechanisms are correspondingly limited.

Figure 16: Summary of capacity mechanism benefits

Benefits of a Capacity Mechanism	Strategic Reserve	Capacity Market
B1. Ensuring Security of Supply	↔	↑
B2. Robust against market power – energy market	↓	↔
B3. Market efficiency: Supports non-generation approaches and promotes long-term demand side	↔	↔
Overall Benefit	↔	↔

Qualitative cost appraisal

6.16 **C1. Cost, practicality and feasibility of implementation**: The institution and business administrative costs of a capacity mechanism are estimated in Section 5 and are shown to be small relative to the impacts on the energy system. Nevertheless it seems likely that there are likely implementation and administrative costs for both options and that these costs would be greater for a market-wide mechanism.

6.17 A Strategic Reserve should be relatively simple to set up and administer as it is a relatively small intervention in the market. However these costs would increase if the size of the reserve were to increase significantly, for example if it were necessary for new plant to be procured to form part of the reserve.

6.18 A Capacity Market is considered likely to be more costly and difficult to set up both because it involves a market-wide auction process for capacity and because it could involve physical and/or financial checks on capacity. It also has a broader and more complex role for delivery institutions, and there is a significant risk of the mechanism being lobbied.

6.19 **C2. Robust against market power – capacity market**: Capacity mechanisms are potentially vulnerable to gaming in the capacity market (i.e. providers withholding supply in the capacity market to drive up prices). The risk of gaming in a capacity mechanism is difficult to assess and is not captured in the energy system modelling.

6.20 A Capacity Market should in theory be competitive given a competitive auction process for capacity being held. However the capacity auction process is potentially vulnerable to gaming, in particular if new or existing players are able to exert market power to drive prices up (e.g. by withholding capacity from the auction process to force up the price or by bidding in at a higher price than necessary). Although we cannot eliminate gaming opportunities in the capacity market at this stage, a number of mitigations are available, such as introducing a sloping demand curve in the auction process – so if capacity prices are high in the auction process, less capacity than the target is procured and vice versa. This may be achievable by having, for example, minimum acceptable and desired levels of capacity. A number of approaches have been used in markets which have implemented Capacity Market-style mechanisms to mitigate gaming opportunities.

6.21 A Strategic Reserve could avoid gaming in the capacity market if there is a plentiful supply of mothballed plant, but is potentially vulnerable to gaming if the type of plant required is in short supply, or if generators indicate that they will close down unless they are moved into the reserve and receive the associated payments.

6.22 **C3. Avoids central determination of parameters**: All capacity mechanisms require an estimate of the level of demand to be made some years ahead. The degree to which mechanisms require other estimates to be made will tend to reduce their efficiency, as it is likely estimates will be incorrect. This will tend to lead to over or under procurement. This cost is likely to be significant although it is not captured in the energy system modelling (which assumes perfect foresight).

6.23 A Capacity Market requires the fewest central estimates. In its simplest form, it only requires an estimate of the level of peak demand; capacity is then procured accordingly. This depends however on the design of the mechanism – for instance, all mechanisms could involve estimating levels of reliable capacity to come from the FiT CfD. A Strategic Reserve requires estimating not just demand but also what the market would have supplied in the absence of the mechanism.

6.24 **C4. Market efficiency: Other**: An energy-only market leads to plant being deployed according to their place in the 'merit order', i.e. their short run marginal cost level. A Capacity Market should maintain optimal despatch incentives. A Strategic Reserve however has the potential to distort this merit order by holding some plants outside of the market, meaning that electricity may not be generated by the most cost-efficient plants available. However any market inefficiency introduced by a Strategic Reserve is likely to be small if the reserve is only despatched as a last resort in exceptional circumstances.

6.25 **C5. Interaction with low carbon measures (FiT CfD and RO)**: The FiT CfD and RO provide support for a Capacity Market or for low carbon capacity – with most capacity becoming low-carbon by 2030.

6.26 The Strategic Reserve avoids direct interactions with the FiT CfD and RO.

6.27 A Capacity Market introduces interactions with the RO and FiT CfD as aligning reliability incentives for plant receiving low carbon support with plant in the Capacity Market risks overpaying the low carbon plant.

6.28 In the energy system modelling it is assumed that this can be achieved without any overpayment of low carbon capacity. We are confident in practice that we can develop proposals for how to manage this interaction, though it will involve some tradeoffs. With RO plant, further analysis is needed of whether allowing their participation in the mechanism is necessary to align incentives or whether it would constitute overpayment of renewables. We are minded to exempt FiT CfD plant from receiving capacity payments and from holding reliability contracts.

6.29 **Overall Cost Assessment**: It is thought that the most significant costs around a capacity mechanism are from over-procurement of capacity if the mechanism is inefficient (C3) and from overpayment for capacity if there is gaming in this new market (C2). On this basis it is thought that the Capacity Market has the potential to be most cost-effective and have least impact on consumer bills. However this is subject to the mechanism being designed in a way that enables a competitive market for capacity, which will be a significant challenge and subject to risk as the mechanism is a substantial intervention in the market. The Strategic Reserve also has the potential to be cost-effective, and reduces challenging interactions with the FiT CfD.

Figure 17: Summary of capacity mechanism costs

Costs of a Capacity Mechanism	Strategic Reserve	Capacity Market
C1. Cost, practicality, and feasibility of implementation	↔	↔
C2. Robust against market power – capacity market	↔	↔
C3. Market efficiency: Avoids central determination of parameters	↔	↔
C4. Market efficiency: Other (including efficiency of despatch incentives, effect on barriers to entry)	↔	↑
C5. Compatible with low carbon measures (particularly the FiT-CfD and RO)	↑	↔
Overall Cost to Consumers	↔	↔

Risk assessment

6.30 **R1. Fit with GB Market:** The ability of a Capacity Mechanism to work in the GB market, and in particular alongside vertical integration and bilateral contracting, is an important consideration in deciding its suitability.

6.31 A Strategic Reserve is thought to have the least impact on the current GB market set-up as it is a limited intervention and should not distort the market signals away from being an energy-only market. A Capacity Market is a more significant intervention and there is some risk around its application in the GB market. In particular, it will be important to design the penalty regime for non-delivery in a way that is compatible with bilateral contracting (e.g. given the challenge of identifying a single reference market). Our work to date indicates that these problems should be surmountable, but there is a risk of unintended consequences when detailed design is carried out.

6.32 **R2. Decarbonisation**: Energy system modelling suggests that both the options have a limited impact on carbon emissions.[19] Our qualitative assessment of the options supports this view: The carbon intensity of electricity generation is primarily affected by other parts of the Electricity Market Reform package, such as the FiT CfD, Carbon Price Floor and Emissions Performance Standard. A capacity mechanism helps to support the decarbonisation of the power sector by ensuring the a decarbonised power sector is still able to deliver security of electricity supply. Moreover if a mechanism helps enable greater DSR then it has potential to aid decarbonisation by reducing the need for peaking plants to be built and then only run in exceptional circumstances.

6.33 **R3. Adaptability:** If it a mechanism were deemed no longer required, a Strategic Reserve has limited exit costs as the amount of capacity procured will be small and, for as long as it procures existing plant, it doesn't need to offer long contracts. A Capacity Market has more significant exit costs as it involves more capacity, though this should be manageable with careful design.

6.34 If the mechanisms were not working and needed to be adapted, the Strategic Reserve poses greater risk as transitioning from a reserve to a Capacity Market would take 6-8 years, and would pose major problems in the interim. A Capacity Market has more potential to be adapted, though this would need to be approached carefully to avoid introducing regulatory risk that would result in investors requiring higher levels of payment if they think the rules mechanism might be changed.

6.35 Estimating the extent and timing of the capacity problem is highly dependent on input assumptions on, for example, level of demand, investor behaviour and the supply mix/extent of de-rating. This means for both Strategic Reserve and a Capacity Market that it will be necessary to have a mechanism fully implemented and ready to run. This is due to the long lead-in times for introducing the legislation, tasking and preparing an institution, implementing the auction process design, running the auction process and the lead time for new investment.

6.36 The initial auction process for Strategic Reserve, will only be run if a problem is detected, there would be no need to procure capacity without a forecast capacity shortfall. This will require a forecast of both demand and generation capacity. For a Capacity Market, part of the design is to only forecast the demand capacity requirement and for capacity providers to offer their reliable capacity in an auction process.

[19] Modelling suggests that a Capacity Market could reduce CO_2 emissions by 13 Mt to 2030. However this is thought to be an artefact of the modelling for reasons explained in 5.9. In practice we expect both mechanisms to have similar and small impacts on CO_2 emissions.

6.37 A Capacity Market is a significant intervention in the market with potentially substantial administrative costs for businesses and for the delivery body. As such, there may be a benefit in avoiding deployment of a Capacity Market until forecasts show a security of supply problem a few years ahead (at which point there is less uncertainty on the scale of the problem). This approach maximises the chance for the energy-only market to deliver the required investment to ensure security of supply. Our modelling suggests a net benefit of £48m from running capacity auctions from 2019 rather than 2015, as there are lower institutional costs and no administrative costs on business in the period up to and including 2018 if no auctions are being run.

6.38 A decision to only run a Capacity Market when required raises two key issues. Firstly, there may be some advantages to introducing a Capacity Market when there is no scarcity to allow the market to gradually evolve. However, there is also a limit to the usefulness of a 'test phase' in a market with excess capacity. If the market is not tight, investors may react differently to a Capacity Market. Secondly, it may exacerbate an investment hiatus or existing parties may prefer a Capacity Market and as such exert influence to ensure its introduction is inevitable. This can at least be partly mitigated by having a fully designed Capacity Market in order to provide certainty to capacity providers on key issues, in particular how they will be treated under a Capacity Market. Furthermore, running an auction process early would be no worse than if a Capacity Market was introduced at the first opportunity.

6.39 **Overall Risk Assessment:** Strategic Reserve has the potential to be the smallest intervention in the market and accordingly has least overall policy design and implementation risk associated with it. The Capacity Market has a higher overall level of design risk given the relative complexity of the model.

6.40 Some of the risk around implementing a Capacity Market can be mitigated by only running the first auction process when a capacity shortfall is detected. This avoids deployment of a Capacity Market until forecasts show a security of supply problem a few years ahead. However it doesn't fully mitigate the risks identified in this section and only running a mechanism when it is forecast to be needed could impact on incentives to invest (although these may be minimised if implemented well).

Figure 18: Summary of capacity mechanism risks

Risks of a Capacity Mechanism	Strategic Reserve	Capacity Market
R1. Fit with GB market (including vertical integration and bilateral contracting)	↑	↔
R2. Decarbonisation	↔	↔
R5: Adaptability	↔	↔
Overall Risk Level	↔	↔

Summary of Qualitative Assessment

6.41 A Capacity Market has more significant benefits than a Strategic Reserve if an energy-only market would fail to deliver the economically optimal level of capacity as it mitigates the risk of regulatory intervention against high prices in the energy market.

6.42 A Capacity Market is also theoretically more cost-efficient than a Strategic Reserve because it procures capacity directly, although this assumes that the capacity market auction process can be designed in a way that minimises opportunities for gaming.

6.43 However a Capacity Market is a larger intervention in the market and has more significant design risk.

6.44 This assessment is summarised in the table below:

Figure 19: Summary assessment of capacity mechanisms

Summary Assessment of Capacity Mechanism	Strategic Reserve	Capacity Market
Benefits		
Costs		
Risks		

7 Conclusion

7.1 The energy system modelling for this Impact Assessment reinforces the conclusions drawn in the Impact Assessment for the Electricity Market Reform White Paper earlier this year: that capacity margins are going to tighten and become a significant cause for concern over the coming decade even if the energy market operates perfectly efficiently. The latest analysis also illustrates however that there is considerable uncertainty in modelling the electricity sector over the medium term and that our assessment of the timing and severity of the future capacity problem is sensitive to a range of assumptions which are subject to change.

7.2 A capacity mechanism serves as an insurance policy against an energy-only market not providing sufficient capacity. In the case of a Capacity Market, it also has the potential (depending on the design) to provide insurance against future price spikes, making consumer energy bills more predictable over time. A capacity mechanism is likely to have a positive net present value if the theoretical market failures result in sub-optimal levels of investment in capacity with associated consequences for capacity margins and energy unserved. Given the importance of electricity to society, a capacity mechanism is a justified and important intervention. The majority of respondents to the December 2010 Electricity Market Reform consultation supported this assessment.[20]

7.3 As illustrated in the qualitative assessment (Section 6), the optimal choice of capacity mechanism design is not clear cut and there is no mechanism that perfectly meets all the criteria:

7.4 A Strategic Reserve has a number of advantages:

- it is relatively easy to implement and exit from;
- it is a well understood mechanism and so has relatively low policy design risk; and
- it is a small intervention in addition to the existing arrangements in the electricity market

7.5 However a Strategic Reserve does not deal with the fundamental problem of 'missing money', that investors might not believe that prices could rise to the level that would justify the optimal level of flexible capacity – and as a result there would be insufficient investment to ensure security of electricity supply. As such, a Strategic Reserve is less likely to be robust against severe or sustained capacity problems.

7.6 A Capacity Market also has a number of advantages:

- it addresses the 'missing money' problem and provides a more stable environment for investment in capacity (including non-generation approaches such as DSR) as providers exchange volatile energy market revenues with a stable revenue stream from the capacity market;
- it can be designed to insure consumers (both domestic consumers and businesses) against the risk of price spikes and so reduce the volatility in consumer bills;
- it reduces gaming incentives for generators in the energy market as generators do not receive rents from price spikes caused by withholding supply; and
- it is in theory the most cost-efficient mechanism to ensure the optimal level and mix of capacity (assuming that the mechanism can be well designed to minimise gaming in the capacity market).

7.7 However the Capacity Market also has some significant challenges:

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

- a Capacity Market is a significant intervention in the market and has greater potential for policy design risks and unintended consequences;
- a Capacity Market, if not well designed, could create opportunities for gaming the new capacity auctions; and
- a Capacity Market is the more costly mechanism to set up and run and it puts a greater administrative burden on businesses who will participate in the capacity market.

7.8 On balance the Capacity Market is assessed to be the best mechanism to ensure security of electricity supply as it addresses the fundamental problem of missing money and because it has potential to be the most cost-efficient mechanism. This is supported by the responses to the consultation, where a Capacity Market was the most widely preferred option.

7.9 Some of the risk around a Capacity Market can be mitigated by only deploying it when there is more certainty of when a security of supply problem will materialise. This reduces the risk that a Capacity Market is implemented unnecessarily. However it will be important to design the implementation strategy in a way that minimises impacts on incentives to invest.

8 Other Impacts

Impact on small firms

8.1 In terms of additional regulatory or administrative burdens, a capacity mechanism will primarily impact on electricity generators in the sector, which are mostly classed as large businesses. However some capacity providers may be small or medium-sized. These will be negatively impacted by additional administrative costs associated with participating in the capacity market and by energy revenues being capped if they take reliability contracts. However these negative impacts should be mitigated from having a more secure and predictable funding. If designed well, the overall effect of a Capacity Market may be to reduce barriers to entry.

8.2 Electricity suppliers will also be impacted by a Capacity Market, in that they will be charged the costs of a Capacity Market and will need to recover the costs from consumers. The design of Capacity Market should minimise any adverse impacts on the financial flows of suppliers but the additional administrative requirements are likely to have a greater impact on small and medium suppliers.

8.3 Further work on the design of the capacity mechanism will look to minimise any adverse impacts on small firms and new entrants.

8.4 Small businesses will benefit indirectly from a Capacity Market through lower consumer bills once the mechanism is deployed (i.e. from 2024 in the central case). The impact of a capacity mechanism on bills is discussed further in Section 5.

UK Competitiveness

8.5 A Capacity Market has the potential to make investment in the UK more attractive by reducing price volatility and increasing and increasing confidence in the reliability of the UK's electricity supply.

8.6 The competitiveness of UK industry is also affected by the bills impacts on business from the capacity mechanism. As shown in the bills section above, depending on the intervention chosen the capacity mechanism could lead to either a marginal increase or decrease in average energy bills for business consumers. However, as mentioned, the bills impacts will depend on the mechanism design and other variables.

Implications for One-In, One-Out

8.7 Based on the latest HMT advice, the Capacity Mechanism options are to be treated as tax and spend measures, so would be out of scope for One-In, One-Out (OIOO).[21]

Equality impact

8.8 It is not envisaged that the Electricity Market Reform capacity mechanism options will impact on 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, 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. We will keep a watching brief on this but we are confident that any issues can be addressed at the design stage without adverse impact on either human rights, or on the effectiveness of the mechanism.

[21] http://www.bis.gov.uk/reducing-regulation

9 Post Implementation Review

9.1 The Department of Energy and Climate Change intends that the first scheduled review of the Capacity Mechanism elements of the Electricity Market Reform (Electricity Market Reform) Programme should take place approximately one year after the first capacity market payments have begun. The date of the review therefore depends on the timing of the first capacity auction process. It would seem appropriate to have regular reviews subsequently to assess the effectiveness of the mechanism and to address significant changes in the environment in terms of decarbonisation and security of supply. At this stage it is too early to put in place a detailed PIR. The department intends to register a full PIR and confirm in detail how the capacity mechanism will be reviewed when it publishes draft legislation to implement Electricity Market Reform.

9.2 Details of the Redpoint model of the electricity market can be found in the Redpoint report which accompanied the Electricity Market Reform consultation document.[22] The modelling approach for the two Capacity Mechanisms is described below, along with the key modelling assumptions that feed into the baseline.

Modelling Assumptions

9.3 A range of assumptions were made for the effects of the different policy instruments to be modelled.[23]

9.4 All options, including the baseline, were set to achieve the same level of decarbonisation and level of renewables deployment in order to make them comparable.

9.5 **Decarbonisation**: the indicative target used is 100g CO2/kWh in 2030, which is the level that would be reached if investors had perfect foresight of DECC's published long-term carbon price. This provides a reasonable goal against which to test the options for reform, since the DECC carbon values are representative of a least cost path to global decarbonisation..

9.6 **Renewables uptake**: Consistent with the lead scenario of the Renewable Energy Strategy, it is assumed that 110TWh of GB electricity demand is met by renewable generation by 2020.

9.7 **Carbon prices**: Budget 2011[24] announced Carbon Price Floor as policy from 2013, and hence this is now included in the baseline rather than as a policy as in the work undertaken for the Consultation Document. In accordance with Budget, the carbon price is set to £16/tCO2 in 2013 rising on a linear trajectory to £30/tCO2 in 2020.

9.8 **Fuel prices**: fuel price assumptions are based on DECC's Updated Energy and Emissions Projections (UEP) October 2011 Central Price case.[25]

9.9 **Demand**: demand assumptions are based on provisional results of the published UEP October 2011 Central scenario for total electricity supply.[26] High Cost scenario demand uses the National Grid demand forecast.[27]

9.10 **Capital costs**: Capital cost assumptions for new build generation have been taken from the report Electricity generation cost model: PB Power update published July 2011.[28]

9.11 **Hurdle rates**: Hurdle rates[29] are based on Redpoint assumptions, informed by market data points where possible. We assume hurdle rates are higher for less mature technologies. Hurdle rate sensitivities come from an assessment by Cambridge Economic Policy Associates.[30]

9.12 **Investor foresight**: Investor foresight of the carbon price is assumed to be 5 years, in line with the assumptions made in the Electricity Market Reform White Paper. There is no assumed foresight of wholesale prices (outside of aforementioned carbon price).

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[22] Available on DECC's website at http://www.decc.gov.uk/en/content/cms/consultations/emr/emr.aspx
[23] Redpoint WP report reference
[24] http://www.hm-treasury.gov.uk/consult_carbon_price_support.htm
[25] http://www.decc.gov.uk/en/content/cms/about/ec_social_res/analytic_projs/ff_prices/ff_prices.aspx
[26] http://www.decc.gov.uk/en/content/cms/about/ec_social_res/analytic_projs/en_emis_projs/en_emis_projs.aspx
[27] http://www.nationalgrid.com/NR/rdonlyres/2450AADD-FBA3-49C1-8D63-7160A081C1F2/47855/DevelopmentofEnergyScenariosTBE2011.pdf
[28] http://www.decc.gov.uk/en/content/cms/about/ec_social_res/analytic_projs/gen_costs/gen_costs.aspx
[29] The minimum rate or return needed for investors to be willing to make a particular investment
[30] http://www.decc.gov.uk/assets/decc/11/consultation/fits-comp-review-p1/3365-updates-to-fits-model-doc.pdf

	Investor Foresight
Carbon price	5 years
Wholesale price	None
Support level	Duration of the contract

9.13 **Biomass conversion**: There's extra potential for converting 4 existing coal plant (Tilbury, Alcan, Uskmouth and Fiddler's Ferry) fully to biomass.

9.14 **Nuclear retirement dates**: New assumptions with regards to nuclear retirement dates, Dungeness B (2020), Hartlepool (2021), Heysham 1 (2021), Hinkley Point (2018), Hunterston (2018), Oldbury (2012) and Wylfa (2012) mean that these are now retiring 2 years later than under the previous Electricity Market Reform modelling runs.

9.15 **Transition/timing**: Most policies are assumed to be implemented in 2014 with two years' notice. The capacity mechanism is assumed to come in when de-rated margins dip below ten% and are expected to remain there.

Limitations of the modelling

9.16 There are important limitations to the modelling, the key ones being:

- It does not account for the administrative costs associated with both the transition to the new market arrangements and the operation thereafter.
- The modelling assumes that policy change would lead to no short-term change in investment behaviour; in practice, there may be some short term impacts.

Strategic Reserve

9.17 The key parameters for the Strategic Reserve option are:

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

Capacity Market

9.18 To capture the effect of reliability contracts, both the contract allocation process (auction) and the effect on the wholesale electricity market have been modelled.

9.19 The auction process is modelled by a 'stack' of the capacity offered into the auction. For simplicity we have assumed that all existing and potential new generators are bidding in their de-rated capacity to the auction. In reality, however, we recognise that some generators (such as wind plant) may decide not to participate in the auction process, or to only offer a percentage of their de-rated capacity.

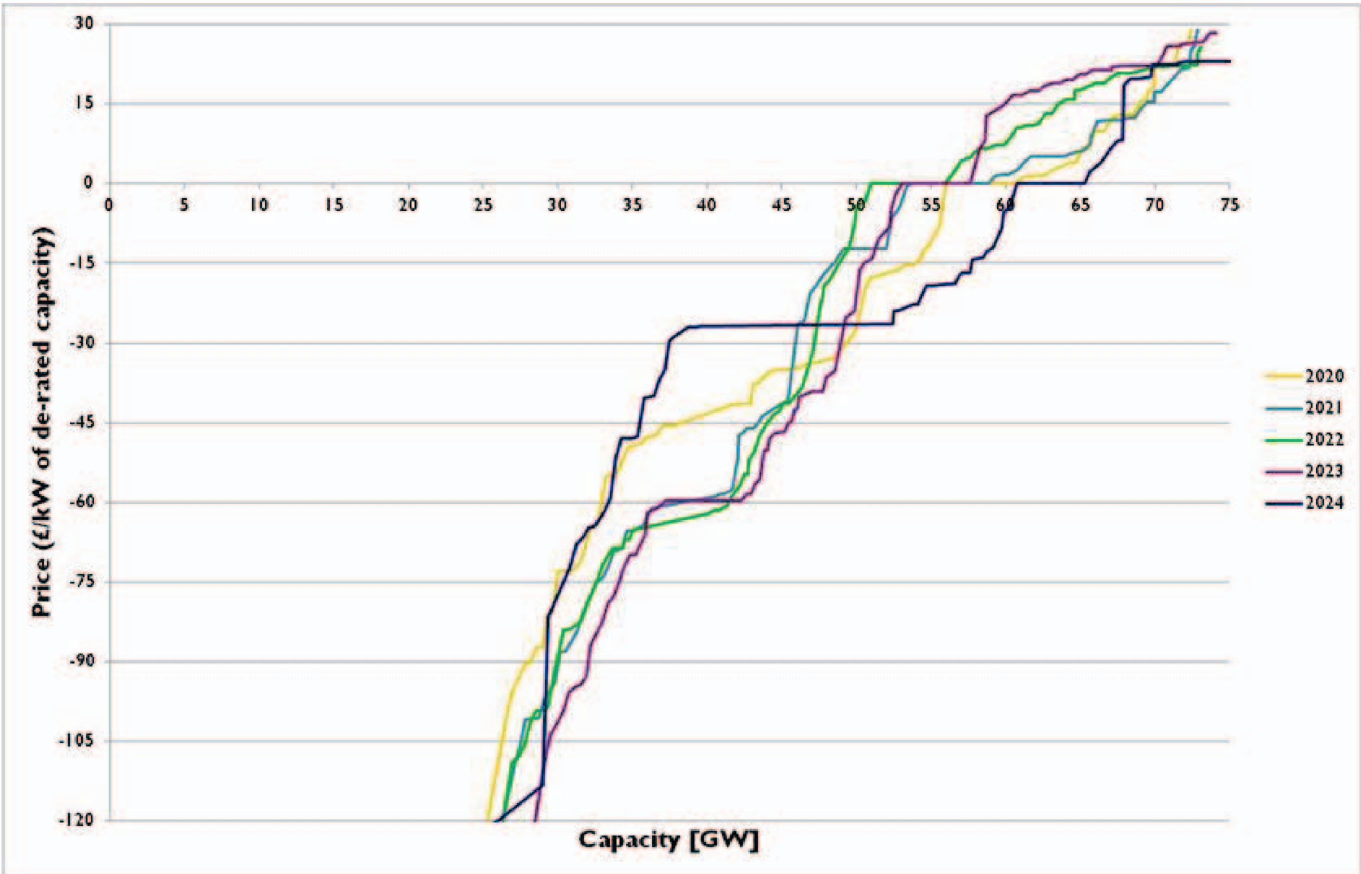
9.20 The bid prices for each generator are calculated based on the required additional revenue to extend the plant lifetime or build a new plant.

9.21 In each year, the auction 'stack' requires as inputs the volumes of capacity offered by each generator or new project and the prices at which this capacity is offered. Each generator offers at a price which makes their generation or project profitable, de-rated by the standard capacity credits in the Electricity Market Reform modelling. From this 'stack', the auction clearing price for each year is calculated, along with which plant receive the reliability contracts.

9.22 The offer prices are calculated as follows:

- Offer price for existing generators (£/kW) = (expected wholesale market revenue – expected generation costs –annual fixed costs) / De-rated Capacity
- Offer price for new generators (£/kW) = (expected wholesale market revenue – expected generation costs –annual fixed costs –annuitised capital costs) / De-rated Capacity

Figure 20: An example of 'the stack' used to calculated the auction clearing price of a Reliability Market.



9.23 The key parameters for a Capacity Market are:

- The volume of contracts bought by the central buyer are peak demand + ten per cent. This is open to all capacity and there is no differentiation based on flexibility.
- Contract length: 1 year contracts for existing plant and ten year contracts for new plant.
- Once a generator has physically closed it cannot re-enter the auction in a later year –i.e. the possibility of mothballing capacity has not been considered.
- Generators use the same de-rating factors as the central buyer.
- Investors have full confidence that the policy will maintain de-rated capacity margins at a minimum of ten per cent.
- Pumped storage hydro plant and interconnectors bid at zero (price-takers).
- Plant that have signed a multi-year reliability contract bid in at zero, while they are being paid the contracted level.
- All plant operating under the Limited Lifetime Opt-out (LLO) mechanism must close in 2023.
- Wholesale electricity market prices never exceed the strike price.
- A reduction in hurdle rates for new CCGT and OCGT generators that receive a reliability contract.
- No change to FiT CfD tariffs, but assumed no increase in build capacity despite higher earnings. For premium payments, tariffs were increased to account for lower wholesale price but the additional RC revenue was not taken into account.

9.24 The table below shows the clearing price in a Capacity Market in the Redpoint model. This would be the highest bid in the stack shown in Figure 20: required to clear the market at the level of electricity demand desired by the central buyer.

Auction Clearing Price (£/kW of de-rated capacity)	**2010-2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**
Capacity Market	0	35.8	30.1	33.0	30.7	29.4	30.6	32.4

Annex B: Impacts on Business

1.1 Businesses would be affected in a variety of ways from a Capacity Mechanism. We have identified three key effects which we have attempted to quantify.

- The change in **producer surplus** that generation companies as a result of the change in the market
- The **administrative costs** on electricity companies associated with participating in a Capacity Market
- Businesses' share of the change in **consumer surplus**.

9.25 A Capacity Market would change the way that generators remunerate investment in capital and change the amount of **producer surplus** that they receive. Generators would now receive revenues from both a Capacity Market and an Energy Market, rather than a single Energy only Market. The impact of this change on generation companies is shown in Figure 8: under producer surplus.

9.26 The **administrative costs** are the costs to businesses of the administrative activities that they are required to conduct as a result of a policy.

9.27 For a Strategic Reserve, it is not thought that there would be any administrative burden imposed on businesses, because it would be centrally organised.

9.28 Ordinary businesses are also consumers of electricity and therefore a proportion of the **consumer surplus** will accrue to them. The savings in consumer bills for businesses are shown in Figure 10. It is estimated that around 62% of electricity consumed was by non domestic consumers.[31] Total consumer surplus is provided in Figure 8.

9.29 These three impacts on business are provided in the table below. Note that the only the final impact is significant for a Strategic Reserve

Figure 21: Cost to Business

	Capacity Market	**Strategic Reserve**
Producer Surplus	-5547	0
Administrative Cost	-97	0
Consumer Surplus	1907	-679
Total business surplus	-3737	-679

[31] DECC statistics for 2009 available at http://www.decc.gov.uk/en/content/cms/statistics/energy_stats/regional/electricity/electricity.aspx