Title: Security of Supply and Capacity Market	**Impact Assessment (IA)**
IA No: DECC0228	**Date:** 6th May 2016
Lead department or agency: Department for Energy and Climate Change	**Stage:** Final
	Source of intervention: Domestic
	Type of measure: Secondary legislation
	Contact for enquiries: energy.security@decc.gsi.gov.uk

Summary: Intervention and Options

RPC Opinion: N/A

Cost of Option 1: Early Capacity Auction				
Total Net Present Value £87m	**Business Net Present Value** No additional cost	**Net cost to business per year** No additional cost	**In scope of One-In, Two-Out?** Not in scope	**Measure qualifies as** Not a Regulatory Provision: Tax and Spend

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

The Capacity Market's (CM) purpose is to ensure an acceptable level of security of supply.

Several market failures exist in the electricity market which means that without intervention the market may not provide adequate security of supply. To address these failures the Government introduced the CM in 2014[1]. The purpose of the CM is to remunerate plants in the market sufficiently and therefore give the correct incentives to ensure capacity is available. Two CM auctions have taken place with delivery (and payments) due to start in 2018/19.

Electricity market conditions in GB have changed considerably since the introduction of the CM. Fossil fuel prices have dropped significantly and weighed heavily on wholesale power prices, having a significant effect on the profitability of both coal and gas plants, particularly the former. This has triggered announced intentions to close earlier than expected, increasing risks to security of supply in 2017/18. Bringing forward the first year of the capacity market by holding an early Capacity Auction for delivery in 2017/18 will help to address these risks.

What are the policy objectives and the intended effects?

The overarching objectives of the CM are:

- Security of Supply: to incentivise sufficient investment in capacity to guard against risks to security of electricity supply by securing the necessary amount of capacity to meet the reliability standard.
- Cost-effectiveness: to achieve the security of supply objective at minimum cost to consumers and without undue distortion of competition and trade.

[1] A more detailed description of the market failures in the electricity market and the rationale for introducing a Capacity Market can be found in our original Impact Assessment for the CM: https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/66039/7103-energy-bill-capacity-market-impact-assessment.pdf

What policy options have been considered, including any alternatives to regulation?

To ensure these objectives are met, the Government has decided to bring forward delivery of the CM and run an early Capacity Auction (early CM) for delivery in 2017/18, one year ahead of the original first CM delivery year.

Section 5 of this Impact Assessment provides further evidence supporting the choice to implement the early CM and compares it to a counterfactual. This counterfactual assumes the system operator can continue to use its Contingency Balancing Reserve (CBR) of up to 3.7GW in 2017/18, to balance the energy system before the CM starts as originally planned in 2018/19.

The option of implementing the early CM improves the security of supply situation substantially. It is also consistent with the decision to implement the CM as the Government's main policy tool in the medium term to guard against risks to security of supply. Also Ofgem considers the early CM to be the preferred method to address any security of supply concerns for 2017/18 as the CBR was not designed to address the risk of tightening margins but to support balancing the system in the transition to the CM.

Will the policy be reviewed? DECC will review the Capacity Market 5 years after its implementation.

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 CO_2 equivalent change in greenhouse gas emissions? (Million tonnes CO_2 equivalent)			**Traded:** 1.8 $MtCO_2$		**Non-traded:** NA

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Summary: Intervention and Options

RPC Opinion: N/A

Cost of Option 1: Improved delivery incentives for the Capacity Market and refined eligibility for Transitional Arrangements				
Total Net Present Value NA	**Business Net Present Value** NA	**Net cost to business per year** NA	**In scope of One-In, Two-Out?** Not in scope	**Measure qualifies as** Not a Regulatory Provision: Tax and Spend

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

To address market failures in the energy market, the Government introduced the Capacity Market (CM) in 2014. The purpose of the CM is to remunerate plants in the market sufficiently and therefore provide the correct incentives to ensure capacity is available. Two CM auctions have taken place for delivery (and payments) to start in 2018/19.

Experience from the past two auctions has suggested that the incentives to be available in the delivery year for plants that were successful in the CM auctions need to be strengthened further. Without amending the policy, there is a risk of capacity failing to meet CM obligations and thus capacity gaps in the delivery years.

When the CM was designed, the purpose of the Transitional Arrangements (TA) auctions was to grow the demand side response (DSR) sector, which was not seen to be sufficiently mature to participate and compete against generation in the main auctions, by providing the opportunity to “trial” the CM process. Evidence from the first TA auction strongly suggests that a significant proportion of the capacity secured in the first TA auction uses generation resources, such as back-up engines and that these units already have a business model that can compete in the main CM T-4 auction.

There is a risk that turn-down DSR is being displaced by more mature generation-based DSR. Without further action, turn-down DSR may receive less of the support it needs and cost-effectiveness of the main CM auctions would be at risk as mature generation DSR is not exposed to the right competition.

What are the policy objectives and the intended effects?

The overarching objectives of the CM are:

- Security of Supply: to incentivise sufficient investment in capacity to guard against risks to security of electricity supply by securing the necessary amount of capacity to meet the reliability standard.
- Cost-effectiveness: to achieve the security of supply objective at minimum cost to consumers and without undue distortion of competition and trade.
- The TA auctions have a specific objective – to grow the DSR sector by helping new DSR providers that are not yet mature enough to compete against generation in the main CM auctions.

What policy options have been considered, including any alternatives to regulation?

To meet these objectives, the Government has decided that the two targeted amendments to the overall CM design regarding delivery incentives and TA eligibility are appropriate.

Sections 6 and 7 of this Impact Assessment provide further evidence supporting these amendments. For this assessment we assume that the early CM is implemented. Through this we are testing whether the CM design changes related to delivery incentives and TA eligibility have an additional benefit over and above the early CM.

The option of amending delivery incentives and TA eligibility is expected to support the policy objectives of ensuring security of supply and cost-effectiveness. They also support the initial policy intent to grow the DSR sector by helping new DSR providers that are not yet mature enough to compete against generation in the main auctions.

Will the policy be reviewed? DECC will review the Capacity market 5 years after its implementation.

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 CO_2 equivalent change in greenhouse gas emissions? (Million tonnes CO_2 equivalent)			**Traded:** NA		**Non-traded:** NA

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: .... ***Date:*** 6 May 2016

Evidence Base

Contents

1 Problem under consideration

1.1 This section gives background information on the Capacity Market (CM) and describes the need for action.

Scope of this Impact Assessment

1.2 This Impact Assessment accompanies the response to the March 2016 CM consultation and examines the case for three policy amendments whose purpose is to ensure security of supply at the least cost through a robust CM design. The main amendment is to bring forward the first delivery year of the CM to guard against short-term security of electricity supply risks with minimum market distortion by introducing an early CM for delivery in 2017/18.

1.3 Two further targeted policy amendments are being taken forward:

i. Improve delivery assurance by increasing credit cover and termination fees in all future CM auctions.[1]

ii. Support innovative demand side response (DSR) models by limiting eligibility in the Transitional Arrangements[2] (TA) auction to turn-down DSR[3].

Overview of the UK Capacity Market and policy amendments

1.4 Faced with the prospect of a tightening security of supply outlook, the Government introduced the CM in 2014. The basic purpose of the CM is to secure the necessary amount of capacity to meet the UK Government's reliability standard[4]. A competitive auction is held ahead of every delivery year and determines the revenue stream (per kW) paid to successful participants who in return commit to invest in 1) new generation capacity, 2) demand reduction or 3) keeping existing plant on the system.[5]

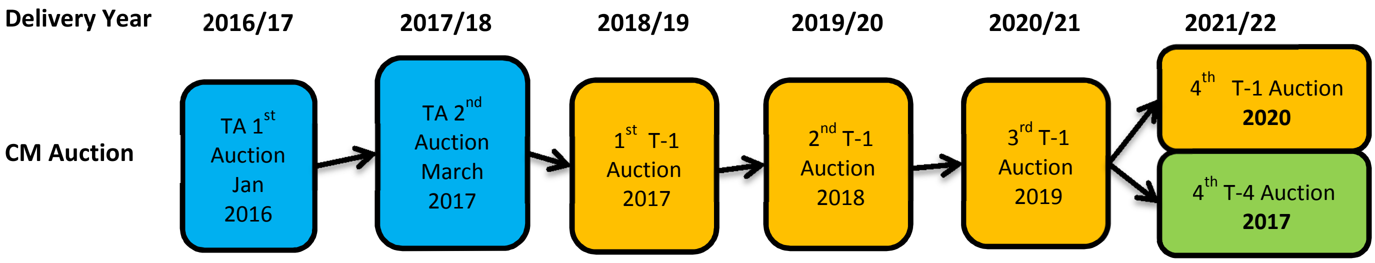
1.5 The CM is designed to secure the capacity needed in a given delivery year through an auction four years ahead (T-4) and a much smaller auction one year ahead (T-1) of the delivery year. The first T-4 CM auction was held in December 2014, for delivery in 2018/19 (October 2018 to September 2019). It secured 49.26 GW of capacity at £20.3/kW (2015 prices[6]). A second T-4 auction was held in 2015, clearing at £18/kW (2015 prices). These low prices were caused by the CM largely supporting existing plant – limited new build plant was procured. Also forecasts of higher wholesale prices at the time may have led plant to bid lower.

[1] This does not include the TA.
[2] Some background on DSR can be found in the following document:
https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/255254/emr_consultation_implementation_proposals.pdf
[3] DSR is the reduction of a customer's demand of electricity against a baseline at a given moment in time. In the CM this can be achieved by load management (e.g. using less power) or through on-site generation such as a combined heat and power plant.
[4] The GB's reliability standard has been set at three hours.
https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/223653/emr_consultation_annex_c.pdf
[5] A more detailed description of the CM can be found here:
https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/324176/Implementing_Electricity_Market_Reform.pdf
[6] £19.40 in 2012 prices.

DSR in the CM framework

1.6 Separately to the CM, two pilot auctions, the TA[7], were developed in recognition that DSR and small scale distribution-connected (embedded) generation was thought to be a relatively small and immature sector and not in a position to compete in the main CM auctions. The TA auctions were intended to provide these resources with a viable route to market by offering targeted, additional support in the two years preceding the first T-1 auction for delivery in 2018/19, thus giving some certainty over revenues during transition to the main T-4 CM auctions. After this point, it was anticipated that these resources would be able to start competing in the enduring CM regime. Figure 1 illustrates the anticipated route to market for DSR and embedded generation capacity. The first of these auctions was held in January 2016 securing 803MW[8] of capacity at a clearing price of £27.50/kW, representing a total cost of £22m[9].

Figure 1: DSR route to market



Delivery incentives

1.7 In the current CM design, any new plant which has gained a capacity agreement and then fails to go ahead faces termination fees, as does any existing plant which fails to have the required transmission connection[10]. Any unit that fails to discharge (or trade out of) its capacity obligation during a stress event also faces penalties. Exposure to these provides the incentive structure for projects participating in the CM to be both available and operational when making their bids.

1.8 Additionally, for new build projects, credit cover requirements are in place and need to be met ahead of reaching their Financial Commitment Milestone (FCM), which is essentially when a plant reaches its Final Investment Decision in its development phase. The credit cover requirements are in line with termination fees at this stage to ensure the taxpayer is able to recover this fee from prospective projects which have failed to proceed by the milestone; where capacity therefore needs to be re-bought through a T-1 auction. The combination of termination fees and credit requirements ensure that risks to security of supply are considered by projects.

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[7] A more detailed description of the TA can be found here: https://www.gov.uk/government/collections/transitional-arrangements-auction

[8] 315MW of the TA capacity is small scale distribution-connected (non-Central Meter Registration Service) existing generation with around 2/3 of this capacity from existing CHPs and the remaining capacity from existing engines; 13MW new generation; 475MW is 'unproven' DSR.

[9] This is the overall cost for the delivery year 2016/17 and will be passed through to consumer bills in the delivery year.

[10] There are 14 types of events which trigger the termination of a capacity agreement, of which 7 have an associated termination fee liability.

Policy amendments

1.9 The Government and stakeholders in the consultation agree that the core CM design is robust and functioning effectively. Nevertheless, there have been significant changes in global energy markets which have led to plant announcing their intentions to close earlier than anticipated during the initial assessment ahead of implementing the CM in 2014. The Government has decided that an additional, earlier CM auction is needed to secure capacity for 2017/18 in order to address the security of supply risks that have emerged.

1.10 Following experience from past auctions, the Government proposes two specific amendments to the overall CM design around improved delivery incentives for CM participants and refined eligibility for the TA. The Government has consulted on these changes and this Impact Assessment presents the evidence base underpinning these amendments.

Need for action to maintain short-term security of supply

Changes in the global energy market have led to unexpected closure risks

1.11 Since the original development of the CM ahead of 2014, energy markets have evolved considerably and unexpectedly. Fossil fuel prices have dropped 50% over the last two years and weighed heavily on wholesale power prices, having a significant effect on the profitability of both coal and gas plants. Until the first half of 2015, spark spreads (i.e. typical gas profitability) were close to zero leading to a significant amount of gas closures. However during the remainder of 2015, the downturn in market conditions have particularly affected the ongoing commercial viability of coal plants. Coal-fired generation profitability has declined more than for gas plants which has resulted in a shrinking market share of coal. Therefore the market is seeing coal plants generate less and take smaller revenues when they run.

1.12 Reference dark spreads, which measure the profitability of coal plants, have fallen by more than 90% since December 2013[11], compared to a corresponding threefold increase in the reference spark spreads, the corresponding measure for gas plants. The impact of this plus carbon costs is that spreads for coal plant are now close to zero and show no prospect of significant improvement in the short term, given depressed year-ahead forward prices.

1.13 These factors and the general electricity market environment has led to operators of power stations to announce possible closure plans in 2016 and a significant increase in the risk of further closure of capacity[12].

Unexpected closures would pose a significant security of supply risk

1.14 The reduction in capacity would have a direct impact on Loss of Load Expectation (LOLE), which measures the average expected number of hours in which supply in the market is expected to be lower than demand under normal operation of the system. In other words, it is the number of hours per year when we expect National Grid to have to use out-of-market or mitigating actions to match supply with demand. Reduced capacity from the announced closures is expected to result in a LOLE higher than the government's reliability standard of 3 hours. See Section 5 for more detail on expected outcomes.

[11]Source: Marex Spectron, Argus and Bloomberg data.
[12] Due to commercial confidentiality, we cannot provide further details.

1.15 In summary, changes in the market have made many plants less commercially viable and triggered announcements of intentions to close. At short time scales, there is no indication of sufficient investment in capacity to replace the gap created. As a result, with no policy action, capacity is expected to be below acceptable levels to meet the reliability standard, with the increased risk of regular tight system margins and action by National Grid.

Need for refinements to the CM design

1.16 Ensuring the overall CM design stays robust is essential to maintain security of supply at the lowest cost. The experience gained since its inception in 2014 – and the recent market developments – indicate that targeted policy amendments are necessary to avoid potentially challenging and costly outcomes, whilst maintaining investor confidence.

Unexpected new capacity shortfalls or delays increase costs to consumers

1.17 Experience from the last two auctions has suggested that the incentives to be available in the delivery year for plants that were successful in the CM auctions need to be strengthened further.

1.18 To secure electricity supply in future years, the CM encourages new build projects to come forward. However, in the existing economic climate, some projects may find it difficult to meet their FCM, despite securing a CM agreement. This raises concerns of delivery assurance from future projects.

1.19 While the risk of new projects being unable to go forward cannot be entirely mitigated, it is important to ensure that projects are incentivised to price bids at levels which can realistically be financed.

1.20 Furthermore, unexpected decline in profitability have led to some existing plant that had already secured a CM agreement, to announce their intentions to close.

1.21 Both instances would occur despite these projects facing a termination fee. This suggests the opportunity cost of terminating their CM agreements given the recent change in the economic climate is not high enough to dis-incentivise closure. For new build, it suggests that the risk of failure is not sufficiently high, which could encourage riskier projects to participate in the CM, which may mean they are less certain to secure appropriate financing.

1.22 Without further action to ensure the incentive structures of the CM remain robust, delivery assurance of the CM would be undermined. Any associated costs that result from doing nothing would accrue to consumers exposed to a lower reliability standard.

Turn-down DSR requires more tailored support

1.23 As set out in 1.6, the purpose of the TA auction was to grow the DSR sector by helping nascent DSR providers that are not yet mature enough to compete against generation in the main auctions.

1.24 DSR in the CM includes different types of DSR resources with different business models. DSR can be achieved through[13]:

i. Turn-down DSR: reducing demand for a short period of time or shifting demand to a different time of the day

ii. Generation-based DSR, which includes:

- Using back-up generators to temporarily reduce demand rather than taking from the grid

- Small scale generation that feeds on-site customer demand and also any surplus generation can be exported.

1.25 Unproven DSR refers to any DSR capacity (either turn-down or generation-based) which has not been tested prior to prequalification in the CM. Proven DSR refers to existing DSR units that have undergone a DSR test and their capacity is known

1.26 Evidence from the first TA auction and the past T-4 auctions strongly suggests that a significant proportion of the capacity secured in the first TA auction uses generation resources. This type of DSR has already been successful in the T-4 CM auction as well as in the wider market prior to the introduction of the CM. These units, therefore, seem relatively competitive and mature compared to load-reduction DSR.

1.27 There is a risk that turn-down DSR is being displaced by more mature generation resources, defeating the original policy intent of the TA auctions. Small scale generation units and generation-based DSR use existing assets that are already viable in the CM under existing market conditions, can be used more cost-effectively in the main CM auctions, in particular, the early CM will also offer the opportunity to earn revenues for 2017/18.

1.28 As a result, without further action, turn-down DSR would not receive the level of support it needs to develop and cost-effectiveness would be at risk as mature generation DSR is not exposed to the right competition.

[13] More information on DSR types can be found here: https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/467024/rpt-frontier-DECC_DSR_phase_2_report-rev3-PDF-021015.pdf

2 Rationale for intervention

Rationale for the Capacity Market

2.1 Given the market failures causing a lack of investment in traditional generation facilities, and given recent reductions of commodity prices, a CM is required to ensure sufficient existing capacity and provide incentives for new-build capacity.

2.2 A more detailed description of the market failures in the electricity market and the rationale for introducing a Capacity Market can be found in our original Impact Assessment for the CM[14].

[14] https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/66039/7103-energy-bill-capacity-market-impact-assessment.pdf

3 Overarching policy objectives

i. **Security of Supply:** to maintain existing capacity and incentivise sufficient investment in new capacity to guard against risks to security of electricity supply and to meet the reliability standard

ii. **Cost-effectiveness:** to achieve the security of supply objective at minimum cost to consumers and without undue distortion of competition and trade.

iii. The TA auctions have a specific objective – to grow the DSR sector by helping nascent DSR providers that are not yet mature enough to compete against generation in the main auctions

4 Policies under consideration

4.1 This section explains the policy options and counterfactuals we have used to assess impacts. It also summarises the discounted policy options.

4.2 Throughout, this Impact Assessment compares Option 1, the policy intervention to doing nothing, Option 0.

4.3 The policy intervention focuses on the early CM for delivery in 2017/18, one year ahead of the initially planned delivery year of the CM. It also covers two targeted policy amendments to the CM design on improved delivery incentives for CM participants and refined eligibility for TA.

Option 0: "Do-nothing" counterfactuals

4.4 For the early CM analysis in Section 5, "do-nothing" would mean: National Grid's Contingency Balancing Reserve (CBR) remains in place for 2017/18 with a cap of 3.7GW as agreed by Ofgem to mitigate times of system stress. We assume CBR would not be expanded beyond this agreed cap on capacity. The CM auctions for delivery year 2020/21 and future years would be held as planned. This is a hypothetical scenario for the purposes of our analysis.

4.5 Sections 6 and 7 of this Impact Assessment provide evidence supporting proposals relating to improving delivery incentives and TA eligibility. For this assessment we assume that the early CM is implemented. Through this we are testing whether the CM design changes related to delivery incentives and TA eligibility have an additional benefit over and above the early CM.

4.6 For Section 6, evaluating changes to delivery incentives, "do-nothing" means: termination fee and credit cover remain at their current level and the early CM is implemented.

4.7 In the counterfactual for Section 7, eligibility for TAs would remain unchanged. Furthermore, unproven DSR with an agreement from the first TA auction would be allowed in the second TA but prohibited from participating in the main CM auctions in 2016/17 (exclusivity provision). Proven DSR and distribution-connected units with an agreement from the first TA are free to enter in to the 2016 T-4 auction.

Option 1: Policy amendments

An early CM for delivery in 2017/18

4.8 This element is to run an early CM in January 2017 for delivery from October 2017 to September 2018. In effect, this will bring forward the first full delivery year of the CM by one year, insuring against security of supply risks that are materialising sooner than expected. The Secretary of State will set the target based on National Grid's recommendation, using the latest evidence base, as part of the normal process.

Improved delivery incentives

4.9 This element will increase and amend the termination fee structure for all plants participating in the CM and raise the credit cover requirements of new build projects. These measures are being introduced to minimise the risks to security of supply of already secured capacity defaulting on their commitments. The changes when implemented will apply to all future CM auctions.

Amendments to eligibility for TA

4.10 This policy element changes the eligibility for TA to allow turn-down DSR to participate in the TA but exclude generation-derived DSR. It will allow unproven DSR with agreements from the first TA auction to participate in the main CM auctions in 2016/17 by removing an exclusivity provision. It reduces the minimum threshold to enter the TA as a DSR unit from 2MW to 500kW. This is intended to grow the DSR sector by helping nascent DSR providers that are not yet mature enough to compete against generation in the main auctions.

Discounted policy option of extending CBR

4.11 The first delivery year of the CM was intended to start in 2018/19. Until then the CBR was to be used to support balancing tight margins in the market. Our counterfactual assumes CBR of 3.7GW could be contracted by National Grid for 2017/18 up to the CBR cap, to balance the system during times of system stress. However, based on our analysis, this would lead to a supply gap and higher levels of unserved energy. Increasing the CBR cap for 2017/18 or bringing forward the CM are the two natural options to consider to secure supply in 2017/18. Both DECC and Ofgem believe that introducing the early CM is the best way to do this.

4.12 Firstly, extending the CBR cap could distort the market by encouraging more plant closures than currently announced, as it may be more attractive for generators to secure guaranteed revenues outside the market than face less certain revenues in the market. This is particularly the case when plant do not believe market prices will rise to sufficient levels to cover their fixed costs. Plants in the CBR have lower costs than plants in the market; they are not required to pay for transmission connection and their running hours are restricted to those during the CBR contract (mainly evening peak hours from October to February) which means less staffing, fuel and maintenance costs.

4.13 The above issue is exacerbated if plant operators believe that the system operator would use CBR aggressively to avoid price spikes, potentially displacing some generation in the market. This could create a further incentive to be in CBR, which would leave margins tighter than necessary, cause more plant to join the CBR and increase prices for consumers, which is often referred to as the 'slippery slope'[15].

4.14 Capacity leaving the market to sit in CBR is a distortionary impact on the market and does not remove the wholesale price spikes. This distortionary impact increases exponentially as more capacity leaves the market.

[15] The slippery slope refers to the idea that a reserve could grow indefinitely. This could happen if plants in the reserve are utilised before the market has been exhausted, depressing the wholesale market price. This would lower the revenues of plant still in the market, causing more of them to consider closure and requiring a larger reserve.

4.15 Secondly, the CBR is seen as less appropriate to address gaming risks than the CM. The procurement for CBR is on 'pay-as-bid' basis through closed bids. The System Operator chooses the cheapest technically viable bids to meet the requirement[16] and so participants can receive different prices for the same amount of capacity. While more and more plants could be interested in entering CBR, it is not a market-wide mechanism and fewer plants than in the SCA compete. As a result more plant could have market power to set the price they wish to obtain for their services, increasing costs to consumers.

4.16 The CM is a technology-neutral market-wide mechanism to securing sufficient capacity, without excluding participation in the energy market. Therefore, we think the CM is the more competitive mechanism and is likely to mitigate market power more effectively. Capacity is procured through a 'pay-as-clear' mechanism where all participants receive the same clearing price, incentivising participants to bid their true cost and to encourage maximum plant efficiency.

4.17 The CM also has a cost control as it sets an auction price cap. This provision does not exist in the CBR, where costs are instead controlled through the procurement methodology. While costs are initially lower for a small and targeted CBR, they increase significantly if CBR expands.

4.18 Extending the CBR cap for 2017/18 would be a decision for the independent regulator. Ofgem considers the early CM to be the preferred method to address any security of supply concerns for 2017/18 as CBR was not designed to address the risk of tightening margins but to support balancing the system in the transition to the CM, which is the key element of the Government's long term policy for ensuring security of supply.

[16] The exact details are set out in National Grid's SBR and DSBR procurement methodologies.

5 Early Capacity Auction

5.1 This option will involve running an early CM in January 2017, for delivery between October 2017 and September 2018, one year sooner than the first full delivery year of the CM was originally planned.

5.2 This section is structured as follows: The quantitative analysis first describes the "do-nothing" counterfactual in more detail. Second, it assesses the costs and benefits of the early CM. Third, the quantitative analysis will examine the distributional effects and net consumer benefit and bill impact estimates. Finally, the qualitative section will complement the analysis by outlining the benefits of the CM design over the counterfactual.

5.3 The early CM will have the same design as the enduring CM and we therefore use its design as the basis for our analysis. However, a few amendments are necessary for adaptation to the necessarily shorter timelines or to reflect the nature of the early CM:

i. Only one year agreements are available in the early CM: our modelling takes this into account when considering the potential bids of new generators;

ii. New build capacity with agreements won in the first two T-4 auctions will be able to prequalify for the early CM for a one year agreement: we have included these plant as potential bidders in the early CM within this analysis;

iii. For clarity, plants that are currently in CBR or mothballed are eligible and also included in our auction modelling.

Quantitative analysis

Counterfactual scenarios

5.4 We have described our hypothetical "do-nothing" counterfactual in Section 4. However, we do not know with certainty how the market would develop and how many plants would close if we did nothing. To reflect this, we have looked at two possible scenarios of the counterfactual for the purposes of this Impact Assessment. We compare each of these scenarios against implementing the early CM and thereby derive the net benefit of implementing the early CM. The two scenarios are as follows:

i. Announced closures: 2.5GW of plant close, as announced in early 2016.

ii. Further closures: 6GW of plant close, including the above 2.5GW plus additional plants that we estimate to be loss-making in early 2016.

5.5 It is important to note that following the announcement of the early CM, plant may have already altered their decisions of whether to close based on expected revenues from the early CM. Therefore these scenarios should be viewed as if the early CM had not been announced.

5.6 Note that both counterfactual scenarios assume that the CBR up to the cap of 3.7GW is in operation.

5.7 We use the UK Government's Dynamic Dispatch Model (DDM) to model the risks to security of supply without the early CM, the results of which are shown in Table 1. The DDM models the whole electricity system, including prices, margins, demand and supply (see Annex A for a more detailed explanation of our DDM model). The fossil fuel price assumptions used in our analysis can be found in Annex B.

5.8 The LOLE[17] is the primary measure of security of supply risk, being the statistically expected amount of hours where demand exceeds supply. Our analysis shows that without taking action LOLE fails to meet the reliability standard of 3 hours in both our plant closure scenarios. This is a hypothetical scenario for the purpose of our analysis.

5.9 Our margins exclude tools used by the System Operator, except for CBR. In the absence of an early CM, we assume the CBR will be set at the cap of 3.7GW, the same level as in 2016/17.

Table 1: Margins and LOLE in 2017/18 in counterfactual scenarios after using CBR up to a cap of 3.7GW

	Modelled Margin	**Modelled LOLE (h)**	**Increase in Expected Energy Unserved[18] (MWh)**
Scenario 1: Announced closures *(2.5GW)*	0%	10	15,262
Scenario 2: Further closures *(6GW)*	-5%	38	79,442

Source: DECC modelling

Benefits

5.10 Implementing the early CM creates benefits, compared to the counterfactuals (assuming announced or further closures), by reducing Expected Energy Unserved (EEU).

Changes in Expected Energy Unserved

5.11 We can measure the benefits by looking at the reduction in EEU which an additional capacity market is expected to deliver. The auction will procure capacity, increasing the supply in the market and lowering the risk of demand exceeding it.

5.12 We take into account the impacts on EEU in two years (2016/17 and 2017/18) as the early CM improves the security of supply outlook before the actual delivery year by incentivising plants to stay in the market rather than close. The estimated benefits do not include the improved security of supply outlook in future auctions or the benefits which may arise from improving liquidity in future T-1 capacity auctions.

5.13 Capacity is lumpy and the CM auction allows securing slightly more or less than the set target if this increases welfare. Our modelling suggests the early CM would result in a LOLE of 2.2 hours, within the Government's reliability standard of 3 hours. This is a substantial reduction from the LOLEs in the counterfactual in Table 1.

[17] Loss of Load Expectation: the number of hours per annum in which, over the long term, it is statistically expected that supply will not meet demand through the market. The GB's reliability standard has been set at three hours LOLE.

[18] This is the amount of electricity demand – measured in MWh – that is expected not to be met by generation in a given year. This combines both the likelihood and potential size of any shortfall. The EEU figure should not be taken to mean that there will be blackouts because we expect that in the vast majority of cases this would be managed without significant impact on consumers.

5.14 EEU is priced at the value that electricity users attribute to security of electricity supply, assumed to be £17,000/MWh[19]. For Table 2 we compared the EEU with an early CM against the two "do-nothing" counterfactuals and present the potential benefit of running an early CM (and reducing EEU) compared to the counterfactual. The benefit is calculated as Value of Lost Load (VoLL) multiplied by the reduction in EEU.

Table 2: Potential benefits from reducing EEU with early CM compared to the counterfactuals

£m (2015 prices)	**Announced closures**	**Further closures**
Change in EEU compared to the counterfactuals, valued at VoLL	£381	£2,887

Source: DECC modelling

Lower demand sensitivity

5.15 Below we set out a sensitivity using a lower demand.[20] As a consequence, benefits will be lower in this scenario, as the security of supply risk is not as high without the early CM, and therefore the early CM has a smaller decrease in EEU.

Table 3: Lower demand sensitivity: Potential benefits from reducing EEU with early CM compared to the counterfactuals

£m (2015 prices)	**Announced closures**	**Further closures**
Change in EEU compared to the counterfactuals, valued at VoLL	£180	£1,797

Source: DECC modelling

Net welfare

5.16 We have calculated a societal net welfare impact, which focuses on the overall electricity system. These include for example carbon, capital or balancing costs. The carbon impacts are related to plants closing in the counterfactual. The benefits of a more secure system clearly outweigh the significantly smaller carbon costs.

5.17 This section also assesses distributional impacts. We again focus narrowly on the period before the CM starts and do not show positive impacts that the early CM may have over a longer time period, for example by increasing liquidity as more capacity stays in the market.

5.18 Our modelling, shown in Table 4, shows the clear benefits of an early CM. This is because closures in both counterfactual scenarios result in a significant level of lost load, which outweighs the cost to the energy system. In the announced closure scenario, net welfare impact is positive; the benefit is significantly higher in the further closure scenario. It is possible, in a lower demand scenario for net welfare to be marginally negative.

[19] Also known as the Value of Lost Load: the estimated value that electricity users attribute to security of electricity supply, i.e. what users would be willing to pay to ensure security of supply in GB. This is based on a study by London Economics: https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/224028/value_lost_load_electricty_gb.pdf

[20] In the sensitivity, we use DECC's demand forecast which is lower than National Grid's. DECC demand can be found here: https://www.gov.uk/government/publications/updated-energy-and-emissions-projections-2015

5.19 For the lower demand sensitivity the announced closure scenario shows a slightly negative impact while the net welfare increases when more plants are expected to close (further closures scenario).

Table 4: Net welfare of the early CM compared to counterfactuals

NPV, £m (2015 prices)	**Announced closures**	**Further closures**	**Lower demand sensitivity**	
			Announced closures	**Further closures**
Carbon cost[21]	-42	-135	-56	-207
Generation cost[22]	-48	-127	-38	-150
Capital cost	-26	-39	-26	5
Network costs[23]	-111	-139	-71	-219
Balancing costs[24]	-41	51	-1	17
Interconnection cost[25]	43	173	7	139
Energy System Costs incl. institutional cost[26]	-227	-217	-187	-417
Reduced EEU	314	2,077	149	1,488
Net welfare	87	1,860	-38	1,071

Source: DECC modelling. Negative values show costs, positive values a benefit.

Distributional impacts

5.20 In the following, the distributional impacts are assessed by comparing the benefits from avoided unserved energy with the potential cost increases for consumers. Cost increases mainly come from capacity payments that are passed through to consumer bills. These are expected to be offset by lower wholesale electricity prices compared to if there was no early CM.

Costs

5.21 To model the costs of the early CM we use a combination of the DDM model and some off-model calculations. We monetise the following costs:

- The costs of capacity payments to generators, which are dependent on the clearing price in the auction;

[21] The total carbon emissions for a year are multiplied by the appraisal value in that year to determine the total carbon costs for that year. An increase in carbon cost, other things remaining constant, leads to a decrease in net welfare.
[22] These are the sum of variable and fixed operating costs. An increase in generation costs leads to a decrease in net welfare.
[23] These are the costs from building the electricity system (TNUoS and BSUoS costs). The increase in cost is mainly network costs from additional generation. An increase in system costs leads to a reduction in net welfare.
[24] These are the costs from operating the electricity system (TNUoS and BSUoS costs). The increase in cost is mainly network costs from additional generation. An increase in system costs leads to a reduction in net welfare.
[25] These measures the cost from electricity imported via the interconnectors net of the value of exports.
[26] An institutional cost estimate, reflecting the cost increase (across 2016/17 to 2017/18) for the CM Delivery Body due to the early CM implementation and operation, is included in the net welfare calculation. As institutional costs are only a National Grid estimate as this stage, we have not shown separately but included in the final net welfare.

- The impact on electricity prices, as the CM is expected to increase supply and avoid the high prices on wholesale and imbalance markets resulting from tight margins;

- The impact on renewable subsidy costs, as expected lower wholesale prices impact contracts signed with low carbon generation. The total cost to the consumer of support for renewables under the CfDs does not change but the balance between wholesale price and CfD payments does;

- The impact on cost from balancing reserves needed by the system operator, as no CBR is contracted in the early CM case and the related costs are saved.

5.22 We measure the impact of the auction over two years, rather than only the additional delivery year. This is because the early CM is assumed to reduce risks to security of supply in 2016/17 as well as 2017/18. This is in line with how benefits were treated. Plant which would otherwise close before 2016/17 in the "do-nothing" counterfactual, will decide to stay open as a result of the early CM.

The costs of capacity payment to generators

5.23 Our estimated cost of capacity agreements has been calculated as the clearing price multiplied by the clearing volume.

5.24 To estimate the clearing price, we used the DDM to model demand and supply in the auction. The demand curve is modelled from the required amount of capacity to reach a LOLE of 3 hours. The supply curve is modelled by determining potential bids of each participant.

5.25 **These modelled clearing prices have been derived very conservatively to test the value for money of our proposals; they do not represent DECC forecasts of the eventual auction clearing price, which may be lower.**

5.26 These bids are derived from the estimated profits and losses of plant between winter 2017 and autumn 2018, an approximation of the period between the auction in January 2017 and the end of the delivery year in September 2018. An adjustment was then made with off-modelling calculations for plants that already have agreements in 2018/19 and/or 2019/20. These plants currently face termination fees of £25/kW for each agreement they have should they close down. Therefore even if a plant is loss making it may be better to stay open. In the adjustment, we took into account the profits and losses made in those delivery years, compared to the revenue received from their capacity agreement. We raised the bids of plant where the losses exceeded the revenue from their capacity agreements and did the reverse for those making profits exceeding their CM revenue.

5.27 The clearing price was estimated from the intersection of supply and demand. A number of sensitivities were then run. Two in which additional liquidity comes forward, pushing the supply up by 500MW and 1GW. Another sensitivity accounts only for the profits and losses for the delivery year – as costs before that could be viewed as sunk. Finally, we present a sensitivity with lower electricity demand. While maybe counterintuitive at first glance, this leads to an increased clearing price, as lower demand pushes down wholesale prices and increases the losses plant make in the market.

5.28 The modelled clearing prices give a total cost of capacity payments between £2bn and £3bn (2015 prices). This cost will also depend on the clearing quantity, which the DDM model calculates in order to meet the reliability standard of 3 hours LOLE. The actual target amount of capacity will depend on National Grid's recommendation and eventual decision by the Secretary of State. As mentioned above this is a very conservative estimate to test the value for money of this option.

Table 5: Estimated clearing prices in different scenarios

2015 prices	**Clearing price (£/kW)**
Modelled clearing price (used for IA unless otherwise specified)	£62
Sensitivity: Sunk costs	£45
Sensitivity: Additional liquidity 1GW	£55
Sensitivity: Additional liquidity 500MW	£58
Sensitivity: Lower demand	£64

Source: DECC modelling

Impacts on the electricity price

5.29 The CM replaces revenues that would have otherwise been obtained in the 'energy only' market when the market would have been short. It is expected that the total costs (wholesale costs and capacity payments) in either case would be roughly equal. However, market failures mean that without a CM, there could be insufficient capacity, leading to higher total costs in the "do-nothing" option.

5.30 The early CM is expected to avoid electricity price spikes, on wholesale and imbalance markets, which are likely to occur with capacity closing. Table 6 shows that wholesale prices rise higher in a "do-nothing" case than in the early CM case.

5.31 In our modelling we observed wholesale prices were sensitive to plant closures as illustrated by the large cost range in the counterfactual scenarios.

5.32 Wholesale price impacts are very uncertain, and have the potential to increase sharply if there are further closures.

Table 6: Changes in electricity prices in wholesale and imbalance markets, comparing early CM and the counterfactuals

<table>
<tr><th colspan="2"></th><th>Absolute cost from electricity prices with early CM</th><th>Absolute cost from electricity prices without early CM</th><th>Reduction in costs from electricity prices</th></tr>
<tr><td colspan="2">Announced closures</td><td rowspan="2">£23.6bn</td><td>£25.1bn</td><td>-£1.5bn</td></tr>
<tr><td colspan="2">Further closures</td><td>£33.9bn</td><td>-£10.3bn</td></tr>
<tr><td rowspan="2">Lower demand sensitivity</td><td>Announced closures</td><td rowspan="2">£21.7bn</td><td>£22bn</td><td>-£0.3bn</td></tr>
<tr><td>Further closures</td><td>£27.9bn</td><td>-£6.2bn</td></tr>
</table>

Source: DECC modelling

5.33 One uncertainty in this analysis is how much of the market will receive high wholesale prices. The majority of electricity is sold in forward markets and therefore only a small proportion of capacity actually obtains the peak wholesale price. However, we make an assumption that when selling electricity in forward markets companies price in the expectation of peak pricing and therefore all capacity is able to capture wholesale price spikes. This might not be true in cases where the market does not expect such high wholesale prices, or where the market does not price in the full value of scarcity, and therefore from this perspective our wholesale impacts may overstate the costs of not implementing the early CM. However, the clearing prices used in the calculation of net benefits for the early CM have been conservative which tends in the other direction.

5.34 In our further analysis, we take a conservative assumption about the response of wholesale prices if the early CM were not to be implemented by focussing on the lower demand sensitivity. We also make conservative assumptions about the wholesale price when CBR is utilised. Balancing market rules mean the price would in theory be set at £3,000/MWh but we conservatively estimate the market price to be £200/MWh[27] as participants may not fully price the expectation of utilisation into forward markets.

5.35 We commissioned external consultants, LCP, to estimate the wholesale price impacts with an early CM and in both of our scenarios, in order to verify the robustness of our results. They have used a more granular version of our dispatch model and a Monte Carlo simulation to estimate the wholesale price effects in the winter of 2017/18[28].

5.36 LCP's analysis confirms that further closures (without the early CM) could result in very high wholesale costs but that there is a large uncertainty to these effects. They estimate that there is an 80% likelihood that total wholesale costs occur in the range £9-26bn, if expected short term price signal are reflected in forward markets. The median figures in this range are above our modelled estimates partly down to the assumptions used, which include a higher price for utilisation of the CBR.

[27] The DDM model also includes CBR utilisation at this market setting price into the wholesale cost calculations, which represents a very small proportion of the total wholesale cost. Our own CBR utilisation costs are estimated at a higher price, based on estimates of the contracts these plant would actually hold with the System Operator.

[28] This is different to DECC's modelling through the DDM where the whole year is considered.

5.37 LCP's modelling suggests there is a 95% likelihood of a saving between the early CM and the further closures scenarios of at least £3.8bn[29]. LCP's measurement is over winter 2017/18, and therefore confirms our own estimate for this year, of £3.9bn[30], is a reasonable and conservative estimate.

Impact on renewables subsidies

5.38 The total costs to consumers of supporting renewables through the CfD are fixed. However since an early CM is expected to prevent the wholesale price increases caused by the closure of plant, there is a change to the way in which this support is provided. In effect more support is provided through CfD top-up payments and less through the wholesale price. This is captured in the assessment, but is essentially an accounting change. These increased costs are not relevant to the last reported LCF budget report.

Impact on costs from balancing reserves

5.39 With the introduction of the early CM, there would be no further need for CBR in 2017/18. This has been confirmed by the regulator, Ofgem[31]. An early CM will therefore avoid availability and utilisation payments made to plant providing this service to National Grid. We estimate the avoided costs by taking estimates of the availability and utilisation costs, based on information from previous tender rounds from National Grid.

Table 7: Avoided balancing costs from introducing an early CM

2015 Prices	**Utilisation Costs**	**Availability Costs**	**Total Costs**
Announced closures	£240m	£139m	£379m
Further closures	£1.4bn	£139m	£1.5bn

Source: DECC modelling

Sensitivities

5.40 We carry out sensitivities to test the variation of the results under different conditions.

5.41 **Lower demand:** We have carried out a lower demand scenario described in Paragraph 5.15. As a consequence of lower demand, wholesale prices do not rise as much without the early CM, increasing the relative cost of implementing the early CM. Net benefits will also be lower in this scenario, as the security of supply risk is not as high without the early CM, and therefore the early CM has a smaller decrease in EEU.

5.42 **Spreads recover:** As outlined in Section 1, market outlook for many plants deteriorated quickly with fossil fuel price changes. Trends in fossil fuel prices could change again and spreads improve before the 2017/18 delivery year, although this is highly uncertain. This could lead to lower bids being placed by generators in the early CM. At the moment – as outlined in Section 1 – uncertainties around security of supply are too large to justify inaction.

[29] This figure includes wholesale price impacts and CBR utilisation at £200/MWh. It does not include the impact on renewable policies or CBR availability payments.

[30] See Table 6 – our estimate of the difference over both 2016/17 and 2017/18 is £10.3bn

[31] https://www.ofgem.gov.uk/publications-and-updates/open-letter-sbr-and-dsbr-201718-given-government-s-consultation-run-ca-delivery-same-year

Total costs

5.43 We use the most conservative of the above costs to calculate net costs for the introduction of an early CM. In Table 8, negative numbers reflect negative cost. The table also presents results from the lower demand sensitivity.

5.44 Table 8 illustrates that the early CM case compares favourably when comparing total costs (including all cost components referred to earlier) in the further closure scenario.

Table 8: Net costs of early CM compared to counterfactual scenarios

£m, 2015 prices	**Announced closures**	**Further closures**	**Lower demand sensitivity**	
			Announced closures	**Further closures**
Wholesale costs	-£1.5bn	-£10.3bn	-357m	-£6.4bn
Resulting change in CfD payments	£38.1m	£279.4m	9.0m	£204.4m
CBR costs	-£379m	-£1.5bn	-379m	-£1.5bn
Cost of CM agreements	£3.2bn	£3.2bn	3.3bn	£3.3bn
Total costs	**£1.3bn**	**-£8.4bn**	**2.6bn**	**-£4.5bn**

Source: DECC modelling

5.45 In a hypothetical, perfectly functioning energy-only market the expectation of higher prices would lead to plant entering, or in the short-term not exiting, the market. Therefore, in theory, there should be no difference in total cost between an additional early CM and leaving the market to respond. In reality, and as our modelling demonstrates, the price increases can be larger. As more plants close and cannot be replaced in the short-term, total cost in the counterfactuals can exceed the early CM case.

5.46 We described the discounted policy option of extending CBR in Section 4. Notwithstanding the concerns around an extended CBR described, the benefits in terms of reduced energy unserved could probably also be met by an extended CBR, not only by the early CM but this could lead to many price spikes of up to the cash-out price of £3,000/MWh in the market before the CBR could be utilised, which would imply costs in the order of the "do-nothing" option. However, running the early CM may be net beneficial even without the unserved energy benefits, as demonstrated in the further closure scenario in Table 8. Whether plants close down or enter the CBR, they do not participate in the wholesale market and prices would be expected to rise as a result of this reduction in supply.

Bill impacts

5.47 The CM is funded through an obligation on suppliers and costs are passed on to consumers through their energy bill. To model bill impacts for the average impact on households we look at the net costs of the early CM compared to doing nothing. Given the early CM affects the market before the delivery year, we look at bill impacts over more than one year, in line with the cost and benefit analysis sections outlined above. It is worth noting that DECC internal bill modelling assumes that wholesale costs are passed through to household bills with a one year lag.

5.48 Bill impacts need to be considered against the backdrop of falling wholesale prices which have reduced bills for consumers compared to the estimates in 2014 when the CM was introduced. Since then, fossil fuel prices have dropped significantly, lowering wholesale power prices. Due to these falling wholesale prices, compared to estimates based on projections in 2014 the average household dual fuel (gas and electricity) bill in 2018 is estimated to be around £180 lower. Consumers should benefit from these falling wholesale prices. But as set out above, they have also had a significant effect on the profitability of both coal and gas plants resulting in announced intentions to close. The gross costs of the early CM add a proportion of this saving back to consumer bills to ensure security of supply.

5.49 The gross impact of the early CM on household bills in 2018 is dependent on the cost of CM agreements. Using our calculated range of between £2bn and £3bn, the gross impact would be between £28-38. However, the estimated gross impact does not show the relevant impact on bills; the relevant impact on bills is the net impact which would be considerably lower due to reduction in wholesale prices, as set out below.

5.50 The net impact on bills is derived from taking the gross costs of the early CM and subtracting wholesale price impacts. This is because the early CM is expected to lead to lower wholesale prices. If only the announced plant closures occur we estimate the net impact on bills to be between £10 and £21 depending on the clearing price in the auction. However, if further closures happened (in the counterfactual) which we think is a credible scenario, leading to greater price spikes in the wholesale market – the early CM would save a net of £46 in 2018 on the average household bill.

5.51 The presented bill impacts ignore that the early CM could have positive implications for later delivery years by keeping plants in the market and increasing competition, which could reduce electricity bills in future years. Hence, there could be further benefits to consumers in later years.

Net consumer benefit

5.52 Table 9 summarises the benefits and costs to consumers.

Table 9: Net benefit

<table>
<tr><th colspan="2">2015 prices</th><th>Total benefits</th><th>Total costs</th><th>Net benefit</th></tr>
<tr><td colspan="2">Announced closures</td><td>£380m</td><td>£1.3bn</td><td>-£1.0bn</td></tr>
<tr><td colspan="2">Further closures</td><td>£2.9bn</td><td>-£8.4bn</td><td>£11.3bn</td></tr>
<tr><td rowspan="2">Lower demand sensitivity</td><td>Announced closures</td><td>£180m</td><td>£2.6bn</td><td>-£2.4bn</td></tr>
<tr><td>Further closures</td><td>£1.8bn</td><td>-£4.5</td><td>£6.3bn</td></tr>
</table>

Source: DECC modelling

5.53 Overall, the analysis shows that the implementation of the early CM would generate between a -£1bn net cost and +£11bn net benefit to consumers. The results are sensitive to the assumptions on closure decisions.

Value for Money of early CM depends on the likelihood of closure decisions

5.54 The above analysis shows a net cost in the case of only announced closures occurring and a net benefit in the case of the further closures scenario occurring. Using the announced closures as a starting point, we can treat the early CM as insurance against the costs of further plant closures in the current market environment. The premium of this insurance is the cost of the early CM compared to announced closures.

5.55 We calculate a breakeven point where it is just value for money to purchase the insurance given a likelihood of the further closures scenarios occurring. This does not take into account other, unmodelled, scenarios and tail risks, and therefore in reality we would expect the breakeven point to be lower (the insurance is value for money at a lower threshold).

5.56 Our analysis shows that the benefits of the early CM will be greater than the expected costs of further closures (in other words the early CM is a value for money insurance product) if the risk of the further coal closures scenario happening is more than 8%. Given the uncertainty on wholesale costs we expect there to be a wide confidence interval around this figure. Using our more conservative “lower demand” sensitivity we calculate the threshold to be 27%, which should give us reasonable confidence that the early CM is a value for money prospect at this threshold.

5.57 Our analysis suggests the supplemental capacity auction is value-for-money even if the probability of the further closure scenario happening is low. In the current market environment, we estimate that a very large amount of coal generation capacity is loss-making, so there is a material risk that further plants would have decided to close had we not announced this measure.

Qualitative analysis

Increasing confidence

5.58 Introducing an early CM for delivery in 2017/18 is a consistent policy choice as it builds on the UK's long-term policy tool for security of supply. Market participants are familiar with the auction process and the institutional framework is set up which should allow smooth delivery.

5.59 The response to our consultation shows that the vast majority of market participants as well as other stakeholders are highly supportive of the introduction of the early CM. Respondents recognised the need to address market developments since the CM was established, and agreed that an early CM is the appropriate response in order to ensure security of supply over delivery year 2017/18.

5.60 As outlined in the quantitative section, the early CM is expected to reduce wholesale price volatility and revenue uncertainty for market participants. It will avoid the risks of managing a potentially tight system including the effects of increased use of National Grid's balancing tools and the CBR. Given the negative margins in the market for 2017/18 which would have resulted from doing nothing, the CBR is more likely to be used more frequently which has potentially distortive impacts on the market. In order to access the CBR, the System Operator has to exhaust all available supply in the market. With an increased CBR, this would become a more frequent occurrence as less plant would be available in the market. Frequent exhaustion of the market and reliance on outside-the-market measures such as the CBR will damage public confidence in security of supply.

5.61 The impact on economic confidence and investment of doing nothing is hard to quantify but is likely to be considerable. The LCP analysis indicates the average number of hours in which a system warning would be issued (measured by the system margin falling below 500MW, an approximation for a potential 'last unit in the market' to come online) and the distribution around these occurrences. Under the two assessed closure scenarios, the average number of hours is 25 and 72. Examining the distributions around these numbers demonstrates the high degrees of uncertainty around these means. It should be noted that under further closures, there is a less than 1% chance of fewer than 10 hours of these tight system margin occurrences.

Reducing wholesale price uncertainty

5.62 Our analysis shows that the wholesale price volatility and uncertainty is very sensitive to the number of plants closing. The CBR exposes market participants to unprecedented market conditions where wholesale prices may reach significantly higher levels but that are extremely uncertain whilst CBR participants benefit from guaranteed revenues and utilisation prices. Furthermore, there may be uncertainty among market participants when the system operator will use the CBR; with a risk that this depresses scarcity rents. These uncertainties could incentivise participants to close earlier than expected, leaving the market artificially tighter than it needed to be.

Limited gaming opportunities

5.63 The CM is a technology-neutral market-wide mechanism to securing sufficient capacity, without distorting the energy market. The CM is the more competitive mechanism and is likely to mitigate market power more effectively. The CM is procured through a 'pay-as-clear' mechanism where all participants receive the same clearing price, procuring the capacity at the lowest possible cost to consumer. Finally, the CM has a price cap which contains cost while at a potentially high level and can mitigate market power.

Summary

5.64 Our quantitative analysis shows that the early CM provides a positive net present value to society as the benefit of reducing energy unserved outweighs the increase in costs.

5.65 Our distributional analysis shows that the early CM potentially avoids increases to the wholesale price, which rises significantly with more plant closing. The net impact on consumer bills is sensitive to these factors. As the amount of closures in the "do-nothing" counterfactual is uncertain, the early CM can be seen as an insurance against these risks.

5.66 Our analysis shows that the benefits of the early CM will be greater than the expected costs of further closures (in other words the early CM is a value for money insurance product) if the risk of the further coal closures scenario happening is more than around 8%.

5.67 Even including gross costs of the early CM, the average household dual fuel bill in 2018 is now estimated to be cheaper compared to estimates made in 2014 before the wholesale prices fell.

5.68 Our qualitative assessment concludes that the early CM, based on the enduring CM design, is seen as the most competitive and consistent policy tool to address short-term security of supply concerns.

6 Improving delivery incentives

Overview

6.1 This section presents the analysis to improve delivery incentives. The costs as well as impacts on generation are described qualitatively.

6.2 To ensure there are appropriate incentives to honour capacity agreements, Government will introduce the following amendments:

i. A higher level of credit cover required for all new build projects at pre-qualification.

ii. Increase termination fees and align them more closely with risks they incur to security of supply/cost of returning to the same level of risk.

iii. Disqualify terminated units from participating in the CM for two years.

6.3 Our qualitative assessment is that the amendments will lead to a potentially very small increase in clearing prices over a ten year period. However, that is balanced out by security of supply benefits.

Increasing credit cover

6.4 This will amend a requirement to hold £5,000/MW in credit cover ahead of the pre-qualification stage, to £10,000/MW. This is a requirement for all new build plant and covers the termination fee, should the project fail to meet their Financial Commitment Milestone (FCM). The credit cover is required to be held for a limited period of time (up to 2.5 years). The credit cover for unproven DSR will not change.

6.5 This amendment is supported by the majority of respondents to the consultation, citing that it would increase delivery assurance and enhance deterrence of speculative projects. Representations also suggested that any increase is unlikely to deter any serious market participants on account of the relatively short period for which credit cover is required to be maintained.

6.6 The minority not in favour of the amendments suggested the amendment may not deter speculative bids and would only result in increasing the cost, and therefore bid price, of new build capacity.

6.7 Respondents also suggested it may present additional barriers to entry, thereby reducing auction liquidity, as well as leading to upward pressure on investors' cost of capital. This could be particularly important at a time when the market's appetite for merchant risk is reduced due to weak wholesale prices. Whilst some respondents cited a barrier to entry, no evidence was received as to why it would affect their *ability* to bid, as opposed to influencing the *price* of their bid.

Increasing termination fees

6.8 This will revise the structure of termination fees as presented in Section 1 of the Government Response.

6.9 Responses in favour of the amendment cited recent market activity, where bidders would rather consider paying a termination fee than fulfil their capacity obligations.

6.10 Some respondents also cited that the auction clearing price would be expected to increase in future auctions in recognition of the need for new build capacity, and as such bidders should be expected to take on additional risk in exchange for their additional returns.

6.11 Those not in favour of the amendments primarily focused on the enhanced market risk, reflected in a higher risk premia, which would result in higher auction costs to consumers.

6.12 Respondents also suggested that the current levels of termination fees are already a substantial incentive not to trigger the termination of agreements, and that any increase may present a barrier to entry, although this has not in practice prevented some closure announcements.

6.13 A sizeable number of respondents highlighted the 'unusual and extreme market conditions' currently facing thermal, especially coal, generation and that any failures (actual or perceived) to honour capacity obligations should be viewed in this context.

Qualitative analysis

6.14 To analyse these amendments to CM legislation, we have assumed investors will revise hurdle rates for new projects upwards. The hurdle rate is the minimum internal rate of return (IRR) required for a project. It is widely used by businesses to make investment decisions for new projects. If a project is unable to meet this minimum IRR, it will not be taken forward. The hurdle rate incorporates exposure to risk, through a risk premia. This in turn is attached to a probability that the project fails and/or is delayed.

6.15 As such, in line with consultation responses, we interpret these amendments as slightly increasing the risk premia associated with a new build project, with investors expected to reflect this increased risk in their hurdle rate.

6.16 Existing hurdle rates are assumed to incorporate credit cover costs and exposure to existing levels of termination fees. We therefore estimate the impact to the IRR of the additional cost that has not previously been factored in. The impact will vary depending on the probabilities attached to failure, however the overall impact is likely to reduce the rate of return to investors. To compensate for this lower return, a higher capacity price will need to be achieved, increasing the price of CM bids.

6.17 As part of consultation with stakeholders and industry, DECC sought evidence on the likely impacts of the amendments. The responses provided helpful insight on the impact of credit cover requirements.

6.18 There is little evidence available regarding investors' attitudes to risk. Therefore we present these impacts qualitatively.

Benefits

6.19 The benefits will depend on when a plant terminates its agreement. For example, a plant that terminates as a result of not reaching its FCM poses a different set of benefits to plant reducing its transmission entry capacity (TEC)[32] or failing to be available in a delivery year it has committed to. As a result, we estimate the benefits that result from:

[32] A request to reduce TEC sends a signal that a plant will not be available to generate at an agreed level.

- Avoiding higher T-1 auction costs, which would have resulted from pressure to secure terminated capacity at the T-1 stage.

- Avoiding costs of EEU, which would have occurred from a reduction in capacity available to generate.

6.20 Estimating the total avoided costs presents many challenges. To do so would require making an assessment regarding the number of plants that fail, for which there is little evidence.

Avoided T-1 auction costs

6.21 A plant that fails as a result of not meeting its FCM but ahead of a T-1 auction poses several issues.

6.22 First, this capacity would need to be repurchased at the T-1 stage. This will put upward pressure on the amount of capacity to secure at T-1 and result in higher policy costs and costs to households, the magnitude of which will depend on the liquidity of the auction. Leading to a loss in consumer welfare.

6.23 Second, if the plant that fails is also the marginal plant that sets the price in the T-4 auction, its failure (assuming its bid was artificially low) reduces the potential revenues that could have been achieved by all other plant that secured an agreement in that auction. Subsequently, the rents that can be acquired by generators at T-1 are potentially much higher. A more rigorous disincentive regime will therefore reduce the risk of higher T-1 costs and encourage reliable projects to secure capacity agreements at T-4, which do achieve FCM.

Avoided unserved energy

6.24 If T-1 is illiquid or if a plant has their CM agreement terminated after a T-1 auction[33] it is likely to lead to an increase in the level of EEU. In this regard, the benefits resulting from these changes can be measured as the reduction in EEU that would occur with an enhanced termination fee and credit cover structure in place.

Costs

6.25 The main cost we identify with these amendments is the cost of capacity payments to generators. The cost of capacity is derived from the total amount of capacity secured in each auction and the clearing price. The impacts on carbon and other costs are expected to be immaterial.

6.26 The policy amendment would affect all future CM auctions. An increase in the hurdle rate will make it more difficult for new projects to come forward unless they are able to secure higher revenues. Revenues from capacity payments will therefore need to be higher to compensate for the added risk exposure from termination fees and credit cover costs. This is expected to put upward pressure on CM bids and therefore the clearing price. However, impacts to hurdle rates are expected to be slight, suggesting the scale of impact on clearing prices will also be small. This is in line with consultation responses suggesting the cost of new capacity will increase.

[33] Such an event could occur for a range of issues for example, construction delays and/or commercial decisions to reduce its transmission connection change.

6.27 Meanwhile, the amount of capacity secured is decided exogenously and determined based on the reliability standard. However, the lumpiness of capacity in the GB electricity market may have an impact on the amount of capacity that clears in future auctions.

6.28 As capacity secured is unlikely to change and there is little impact on clearing prices, changes to overall policy costs are likely to be very small.

Impact on generation mix and smaller players

6.29 Overall, the changes in hurdle rates should not generally impact the generation mix; however, there is uncertainty as to the impacts in specific years.

6.30 This is the consequence of the hurdle rate changes feeding into the bid formation process. The result is that it changes the position of the project in the stack of bids that form the auction supply curve. The cheaper the bid, the more likely it is to clear.

6.31 The impact of the amendments is likely to leave larger projects unaffected compared to smaller projects. However, the magnitude of the impact is likely to be small and have no material impact to the generation mix, suggesting that the amendments do not present a significant barrier to entry.

Impact on existing technologies

6.32 Existing technologies will not face the same exposure as new build projects in terms of securing additional credit cover and/or reaching a FCM. However, they will be impacted by exposure to higher termination fees (e.g. reducing TEC), increasing the opportunity cost to terminate their agreement.

6.33 Similar to analysis on new build, we expect existing plant will also reflect the exposure to higher termination fees in a higher risk premia, subsequently leading to a higher hurdle rate. To reach this higher hurdle rate, plant may require higher CM payments to compensate for the additional risk, leading to higher CM bids.

6.34 The overall impact will depend on the degree to which changes in hurdle rates alter the order of bids in the auction supply curve. For example, if the relative changes in hurdle rates (of existing and new build plant) lead to existing plant being able to offer capacity at a lower cost than new build plant, fewer new build plant will be seen securing CM agreements.

6.35 The likelihood of existing generators terminating their agreement is low relative to new build projects; therefore we anticipate a relatively small increase in the hurdle rate, which is unlikely to impact the order of bids in the auction supply curve.

Impact of disqualification

6.36 The impact of disqualification is difficult to quantify. The likely impact will depend on whether the project bidding into the CM is new or existing. For existing projects, the disqualification increases the opportunity cost of terminating a CM agreement after T-1. For new build, the risk attached to failure of delivery is held by the owner of the project, as they will bear the costs of disqualification as opposed to the project itself, which can be sold and entered into a future CM auction with a new owner. The probability of such events is small. For this reason, we expect this to have a very minimal impact on hurdle rates.

Increased confidence

6.37 It is intended that a higher hurdle rate will dis-incentivise speculative projects. With the higher hurdle rate priced into bids, speculative projects are less likely to clear. As a result, those that are more certain to reach their FCM and have construction plans in place are likely to have relatively lower risk premia associated to their projects. This will lead to more secure new build capacity being successful in the CM; providing increased confidence that new build projects participating in the CM will be ready in time to deliver and minimising risks to security of supply. This gives households and businesses confidence in the GB electricity system, leading to wider benefits to industry and to the economy.

Summary

6.38 As set out previously, all other energy system costs associated with the implementation of the amendments, such as carbon, network, balancing costs are negligible. We do not explicitly show net welfare.

6.39 Benefits from reducing unserved energy from non-delivery could be substantial. However, the benefits depend on the assumptions around likely non-delivery, the probability of which is unknown. Therefore, we do not compare costs and benefits directly. Improving delivery incentives is justified given that policy costs are small over a ten year horizon and there are important benefits associated with a more secure electricity system.

6.40 On balance, we believe the changes as described in our qualitative assessment indicate a net benefit.

7 Amendments to eligibility for Transitional Arrangements

7.1 The following section qualitatively assesses the impact of amending the eligibility for TA, covering potential benefits of DSR, past experience from CM and TA auctions and the distributional impacts of the policy amendment.

Background on expected DSR benefits

7.2 Currently the following types of capacity are eligible for the TA :

- Turn-down DSR: reducing demand for a short period of time or shifting demand to a different time of the day
- Back-up generation DSR: using generators to temporarily meet on-site requirements and/or export energy to the grid.
- Distribution-connected generation: mainly standalone units below 50MW.

7.3 DSR has the potential to play an important role in delivering a smart, flexible energy system in the UK and, as a consequence, the following associated benefits:

- Defer or avoid investment in network reinforcement.
- Reduce the need for a significant increase in reserve generation capacity.
- Meet binding climate change targets (if turn-down).
- Make the best use of our low carbon generation (by minimising the periods during which it may otherwise be curtailed).
- Optimise balancing of our energy system on a minute-by-minute basis.

7.4 The National Infrastructure Commission's report[34] found that Smart Power – principally built around three innovations - interconnection, storage, and demand flexibility – could save consumers between £2.9 to £8 billion a year by 2030. However, it is important to realise, that the impact of this becomes significant in the medium term and will not reduce the need for new build capacity in the short term.

7.5 Consistent with the policy objectives listed earlier, the Government wishes to ensure the design of the TA auctions helps to grow the DSR sector, which was not seen to be sufficiently mature to participate and compete against generation in the main auctions without the opportunity to "trial" the CM process.

Qualitative analysis

Past experience from TA and CM auctions supporting the policy amendment

7.6 Evidence from the first TA auction and the past T-4 auctions strongly suggests that a significant proportion of the capacity secured in the first TA auction is from existing generation resources and also generation-based DSR. Similar generation-based solutions have already been used successfully in the wider market prior to the introduction of the CM.

[34] https://www.gov.uk/government/publications/smart-power-a-national-infrastructure-commission-report

7.7 The level of participation and success of generation-derived DSR, not only in the first TA auction, but also in the 2015 T-4 auction and wider market, indicates that the this type of resource is relatively competitive and mature. Some more detailed observations of the first TA and CM auctions were:

TA auction

- The first TA auction secured 315MW of existing distribution-connected generation (two thirds of this was from existing CHPs[35] and the remainder from existing gas and diesel engines) and 13MW of new distributed generation.

- The first TA also procured 475MW of 'unproven' DSR. Unproven DSR is effectively an 'empty vessel' which has yet to be filled with specific DSR resources – these are recruited in the run-up to delivery and become 'proven' during a testing process. It will contain a mixture of both generation-derived and turn-down DSR.

Share of generation-based vs turn-down DSR

- Although an exact breakdown is not known definitively at this stage, based on early interviews with DSR providers, undertaken as part of DECC's TA evaluation study, expectations are that a substantial proportion, approximately 50-80% of the 475MW is likely to consist of generation resources.[36]

- Table 10 below shows how the assumption that 50 to 80% of unproven DSR is generation-based translates into the total amount of generation-based DSR in the TA. The overall proportion of TA agreements using generation assets is likely to be between 70 – 90%.

Table 10: Potential share of turn-down vs generation-based DSR in first TA auction

	Unproven DSR	**Total TA**		**Unproven DSR**	**Total TA**	
	Assumption: 80% of unproven DSR is currently generation based			Assumption: 50% of unproven DSR is currently generation based		
	MW	MW	%	MW	MW	%
Generation based share of TA	380	708*	**0.9**	238	566*	**0.7**
Turn-down capacity in TA	95	95	**0.1**	238	238	**0.3**
Sum	475	803		475	803	

Source: Early indications from the external TA evaluation. *includes distributed generation: 13MW new, 315MW existing.

[35] Combined Heat and Power.
[36] We received only limited feedback to the March 2016 consultation but one participant mentioned that they expected generation-derived DSR to make up 85% of the capacity successful in the first TA auction.

Generation-based DSR seems mature

- Early indications from the external TA evaluation are that many participants were able to bid into the auction well below the clearing price.
- Generation-derived DSR does not only make up the bulk of the DSR successful in the TA but also appears to make up the majority of DSR currently active in the UK.
- Some of the DSR capacity participating in the TA auctions is clearly mature enough to participate in the T-4 auction. For example, of the 1600MW of capacity that pre-qualified for the TA auction, 350MW also pre-qualified for the 2015 T-4 auction.
- It is also worth noting that the success rate of unproven DSR in the T-4 auctions has improved significantly between auctions. The share of unproven DSR winning agreements over the unsuccessful units increased from 28% in 2014 to 67% in 2015, illustrating the degree to which the sector has already developed from experience gained through the first auction. In the 2015 auction, 450MW of unproven DSR won an agreement.

Stakeholder feedback to the consultation

- The majority of stakeholders agreed with our proposal of restricting the eligibility for the second TA to turn-down DSR. Some stakeholders raised concerns that a mix of generation-based DSR and turn-down DSR should still be allowed in the second TA. Further detail on the stakeholder feedback can be found in the Government response.[37]
- Representations in support of the proposal pointed to 1) generation-derived DSR are crowding out turn-down DSR from the first TA auction, 2) the higher barriers and cost bases for turn-down DSR, 3) the availability of existing embedded benefits for generation-derived DSR, and 4) the existence of an alternative route to market for generation-derived DSR following the introduction of the early CM auction for delivery in 2017/18.

7.8 In the light of this experience, the Government expects generation-based DSR units to be ready to compete in the main CM auctions. This avoids generation-based DSR displacing turn-down DSR in the TA auction which was designed to support an immature sector.

[37] https://www.gov.uk/government/collections/capacity-market-2016

Distributional impacts

7.9 Impacts on consumers can be derived by assessing the changes in clearing prices, in the TA as well as the CM auction.

Scenarios and counterfactual

7.10 We present the impacts comparing:

- Option 0 ("do-nothing"): Generation-derived DSR would still be able to compete in the 2017 TA auction. Unproven DSR with an existing TA agreement (from the January 2016 TA auction) would be held out of the early CM and T-4 (delivery 2020/21) due to an existing exclusivity provision – its only option would be to participate in the second TA auction.

- Option 1: Prevent any form of generation being eligible for the second TA auction. Reduce the minimum threshold to enter TA to 500kW. Remove an exclusivity provision to allow all capacity that secured an agreement in the first TA auction to enter the main CM auction to be held in winter 2016/17 – both the early CM for delivery in 2017/18 and the T-4 auction for delivery in 2020/21.

Cost reductions in the TA auction

7.11 Targeting TA eligibility to turn-down DSR should ensure funding is directed to where it is needed most – the least developed part of the DSR sector.

7.12 Whilst it's difficult to accurately predict the outcome of any competitive auction, it's not unreasonable to assume that, if the eligibility criteria remained unchanged (Option 0: "do-nothing") the second TA could clear at a similar price as the first TA and to deliver predominantly existing small scale generation assets and mature generation-derived DSR. Whilst it might be expected that more DSR resources would come forward for the next TA auction (encouraged by experience and high clearing price of the first auction compared to the CM auctions), it is also possible that the distribution-connected generation units (328MW) could choose to transition to the early CM if they expect a higher clearing price in this auction than in the next TA.

7.13 Refining the eligibility criteria (Option 1) could potentially lead to a higher TA clearing price, as a result of the specific challenges the sector may face in developing turn-down capacity. However, the auction is likely to target a smaller volume reflecting the potential of turn-down DSR in the market. As set out in Table 10, we estimate that between 95-238MW of DSR was turn-down in the first TA, which translates to 10-30% of the total clearing capacity (see Table 10). The amount to procure will be set in June 2016 as part of the CM parameters. The overall cost of a second smaller TA is expected to be below the total cost seen in the first auction (£22m).

7.14 It is also reasonable to assume that refining the eligibility criteria (Option 1) will deliver greater benefits by ensuring space is created for, and funding directed to, greater amounts of turn-down DSR. Whilst it is not possible to quantify, the benefit derived from this expenditure will be realised by incubating early growth of a larger amount of load-reduction DSR, enabling it to better realise the benefits associated with smart energy systems (described earlier) over the longer term.

7.15 Refining the eligibility criteria does create market power risks which could result in a high clearing price. However, lowering the TA eligibility to 500kW could bring on more (smaller) players and therefore increase competition. Furthermore, gaming risks can be mitigated through appropriate auction parameters and the Secretary of State has existing powers to postpone and cancel auctions if such concerns arise.

7.16 It might be expected that more DSR resources come forward for the next TA auction, encouraged by experience and high clearing price expectations. This could reduce the saving in the TA but be fully in line with the policy intent.

Cost reductions in the CM auctions

7.17 Under Option 0 ("do-nothing"), all 328MW of small scale distribution connected generation holding a TA agreement would be free to prequalify for the second TA and the early CM. It is expected that a large proportion could chose to bid into the early CM, depending on the relative price expectations of the two auctions. Under Option 0 ("do-nothing"), all 475MW of unproven DSR with an existing TA agreement (won in January 2016) would be held out of the T-4 (delivery 2020/21), if it applied again as an unproven DSR due to an existing exclusivity provision – its only option would be to participate in the second TA auction (this assumes the agreement holders do not renege on their commitments).

7.18 In a scenario where eligibility of the TA auction is changed (Option 1), all of the 328MW of small scale distribution-connected generation is pushed out of the second TA auction and into the early CM and the CM auctions for delivery year 2020/21 (either T-4 in 2016 or the later T-1). A significant proportion (50-80%) of the 475MW of unproven DSR is also pushed out because it is generation-based DSR. However, the removal of the exclusivity provision means this capacity is now allowed to participate in the early CM and the CM auctions for delivery year 2020/21.

7.19 Generation-based DSR providers should not be worse off as the introduction of the early CM offers a replacement opportunity for these resources. Information from the supply curve of the first TA auction indicates this capacity should be competitive in the early CM. It is worth noting that CM and TA agreements are different, mainly because the credit cover for new units is higher in the CM than in the TA. However, the credit cover for DSR in the CM has not changed[38] due to our amendments set out in Section 6 and that DSR has met these requirements successfully in previous T-4 auctions.

7.20 The removal of the exclusivity provision of the proposals will therefore act to shift between 238 - 380MW[39] of unproven DSR out of the second TA and into the early CM and the T-4 CM auction for delivery year 2020/21.[40] Removing the exclusivity provision will lead to the remaining turn-down DSR participants being able to choose which auction to enter, the TA or the early CM for the delivery year 2017/18. The supply curve of the first TA auction suggests that the generation-based DSR are able to accept a low clearing price and should therefore act to increase competition in the CM auctions and bear down on the clearing price.

[38] Credit cover remains at £5000/MW for DSR units in the CM.
[39] 50 - 80% of 475MW.
[40] These would be in addition of unproven DSR units which have already participated in previous CM auctions.

Summary

7.21 This section evaluated qualitatively the impacts of modifying TA eligibility. The amendment is expected to support the least developed DSR to develop its potential and to participate in the CM auctions in the future.

7.22 In summary, we expect to improve value for money when limiting TA eligibility to turn-down DSR and transitioning DSR assets that are mature into the CM auctions. It ensures generation-based DSR compete on a level playing field with other market participants, and that we can nurture turn-down DSR (which reduces costs, improves security of supply, and decarbonises in the most appropriate way).

8 Conclusion

8.1 The first T-4 CM auction was held in December 2014, for delivery in 2018/19 (October 2018 to September 2019). It secured 49.26 GW of capacity at £20.3/kW (2015 prices)[41]. A second T-4 auction was held in 2015, clearing at £18/kW.

8.2 Energy markets have evolved considerably and unexpectedly since the introduction of the CM. Fossil fuel prices have dropped considerably, having a significant effect on the profitability of both coal and gas plants. To address the possible threat to security of supply the Government has decided to bring forward the start of the CM and run an early CM for delivery in 2017/18.

8.3 The Government is committed to maintaining a robust CM framework, whilst at the same time retaining value for money for GB consumers. It has therefore been decided that two targeted amendments to the overall CM design, with regards to delivery incentives and TA eligibility, are appropriate.

8.4 This Impact Assessment has first evaluated the early CM implementation in a quantitative and qualitative analysis in Section 5. The quantitative analysis indicates that the early CM is justified by high risk of closure of plants. In the short term there are gross increases to household bills but these are more than offset by recent wholesale price falls; and in a scenario of further plant closures there would be a net saving on household bills compared to “do-nothing”. In the longer term the impact on bills is expected to reduce further. The qualitative analysis gives more detail why the early CM, based on the overall CM design, is seen as the most competitive and consistent policy tool to address short-term security of supply concerns.

8.5 Section 6 analyses the option of improving delivery incentives quantitatively. It calculates the impact of amendments to credit cover and termination fees on the hurdle rate of different project types. In a next step, the DDM is used to evaluate the effect of changed hurdle rates on future auction outcomes. As set out above in Section 6 the increase in clearing prices would be small and there are clear benefits to making the changes that we have described qualitatively. This is why the Government has decided to amend delivery incentives.

8.6 Section 7 evaluates qualitatively the impacts from modifying TA eligibility. The change is expected to grow the DSR sector by developing nascent turn-down DSR, which was not seen to be sufficiently mature to participate and compete against generation in the main auctions without the opportunity to “trial” the CM process. We expect to improve value for money when allowing mature generation DSR technologies in the CM auctions, and not in the TA, as they will compete on a level playing field with other market participants in the broader CM.

[41] £19.40 in 2012 prices.

9 Other impacts

Business administrative costs

9.1 A CM is likely to create an administrative cost for business in that they need to undertake additional activity to access the auction, for example developing a bidding strategy. We do not expect these costs to be significant because of the proposed policy changes as business have already adapted to the CM process.

Institutional costs

9.2 These represent the administrative costs of running the CM process overall. We expect them to only increase for the early CM and have reflected this in the net welfare section. Generally, the infrastructure necessary to run a CM are already in place and serviceable as a result of the wider CM programme.

Impact on small firms

9.3 The majority of electricity generators are 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 CM, compared to larger firms. However, these negative impacts should be mitigated from having a more secure and predictable funding. For the early CM, we do not expect additional costs as firms will already have incurred transition costs to enter other CM auctions. The changes to termination fees and credit cover may impact smaller generators more in comparison to larger plants and these effects are set out in the relevant policy sections.

9.4 Electricity suppliers will also be impacted by a CM, in that they will be charged the costs and will need to recover the costs from consumers. We do not expect additional administrative requirements by the policy changes set out in this Impact Assessment.

UK competitiveness

9.5 There are no additional impacts by the proposed policy changes. The CM has the potential to increase net energy bills, which could negatively affect UK competitiveness. However this cost needs to be weighed against the fall in the wholesale prices (which is causing the problems for coal and gas plants) and considered against the significant harm to UK competitiveness that could arise if the market failed to deliver security of supply objectives, leading to supply shortages with even higher energy bills and much lower security of supply, both of which could have a damaging impact on the UK's reputation.

Implications for One-In, two-Out

9.6 Based on the latest HMT advice, the Capacity Market options are to be treated as tax and spend measures, and are therefore not regulatory provisions. For this reason the impacts of the changes are out of scope of One-In, two-out (OITO) and the Business Impact Target (BIT).

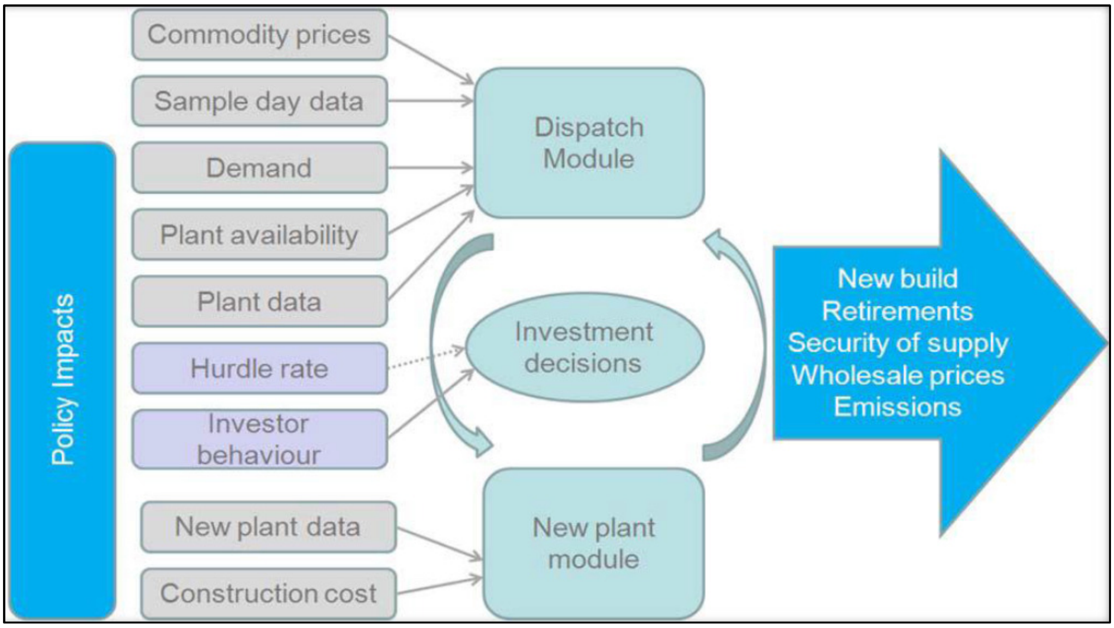
Annex A: Energy system modelling

1. The Dynamic Dispatch Model (DDM) is a comprehensive fully integrated power market model covering the GB power market over the medium to long term. The model enables analysis of electricity dispatch from GB power generators and investment decisions in generating capacity from 2010 through to 2050. It does so by considering electricity demand and supply on a half hourly basis for sample days. Investment decisions are based on projected revenue and cash flows allowing for policy impacts and changes in the generation mix. The full lifecycle of power generation plant is modelled, from construction through to decommissioning.
2. The DDM enables analysis comparing the impact of different policy decisions on generation, capacity, costs, prices, security of electricity supply and carbon emissions, and also outputs comprehensive and consistent cost-benefit analysis results.

Overview

3. The DDM is an electricity supply model, which allows the impact of policies on the investment and dispatch decisions to be analysed. Figure 1 below illustrates the structure of the model.

Figure 1: Structure of the Dynamic Dispatch Model (DDM)



4. The purpose of the model is to allow DECC to compare the impact of different policy decisions on capacity, costs, prices, security of electricity supply and carbon emissions in the GB power generation market.

Dispatch decisions

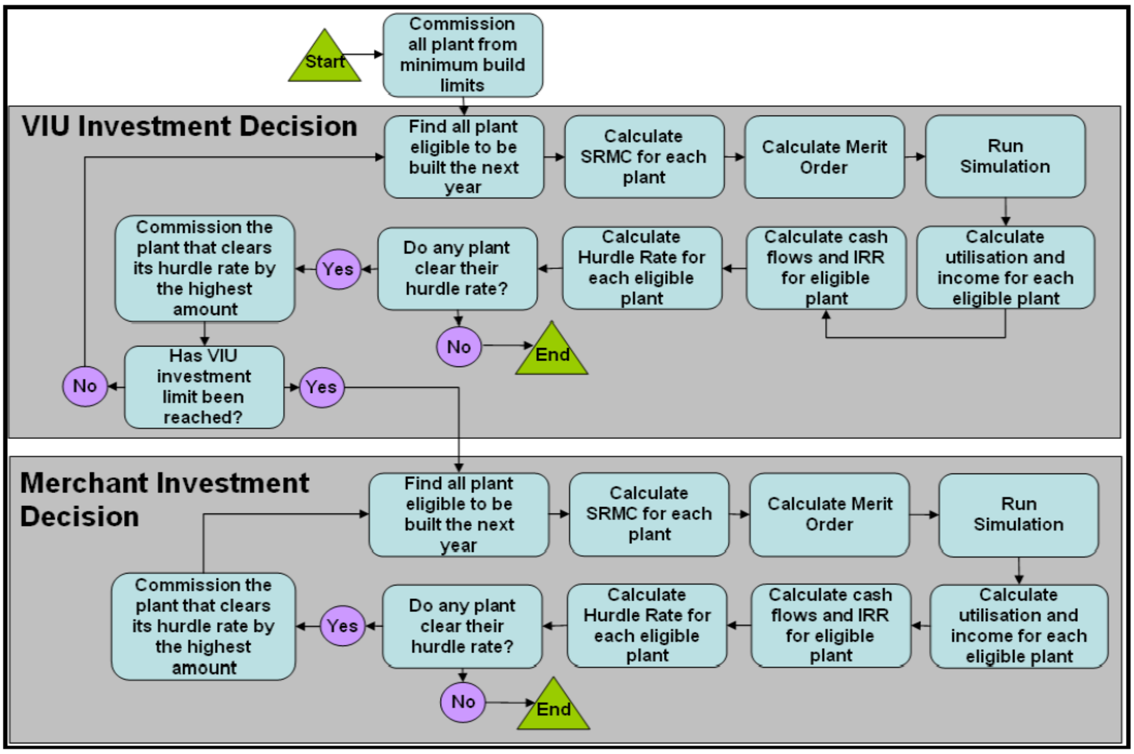
5. Economic, energy and climate policy, generation and demand assumptions are external inputs to the model. The model runs on sample days, including demand load curves for both business and non-business days, including seasonal impacts, and are variable by assumptions on domestic and non-domestic sectors and smart meter usage. Also, there are 3 levels of wind load factor data applied to the sample days to reflect the intermittency of on- and off-shore wind. The generation data includes outage rates, efficiencies and emissions, and also planned outages and probabilities of unplanned outages.
6. The Short Run Marginal Cost (SRMC) for each plant is calculated which enables the calculation of the generation merit order. Demand for each day is then calculated taking wind profiles into

account and interconnector flows, pumped storage, auto-generation and wind generation. Once the required reserve is calculated the system SRMC is calculated by matching the demand against the merit order and taking the SRMC of the marginal plant to meet demand. The wholesale price is equal to the system marginal price plus the mark up. The mark up is derived from historic data and reflects the increase of system marginal price above marginal costs at times of reduced capacity margins. Plant income and utilisation are calculated and carbon emissions, unserved energy, and policy costs are reported.

Investment decisions

7. The model requires input assumptions of the costs and characteristics of all generation types, and has the capability to consider any number of technologies. In investment decision making the model considers an example plant of each technology and estimates revenue and costs in order to calculate an IRR. This is then compared to a user specified technology specific hurdle rate and the plant that clears the hurdle rate by the most is commissioned. This is then repeated allowing for the impact of plants built in previous iterations until no plant achieves the required return or another limit is reached. The model is also able to consider investment decisions of both Vertically Integrated Utilities (VIUs) and merchant investors, see Figure 2 below. Limitations can be entered into the model such as minimum and maximum build rates per technology, per year, and cumulative limits.

Figure 2: Investment decisions in the DDM



Policy tools

8. The model is able to consider many different policy instruments, including potential new policies as well as existing ones. Policies are implemented by making adjustments to plant cash flows which either encourage or discourage technology types from being built in future and impact on their dispatch decisions. The policy modelling has been designed flexibly and policies can be applied to all technologies or specific ones. Policies can be financed through Government spending/taxation or charged to consumers.

Outputs

9. The model can be run in both deterministic and stochastic modes – this enables analysis to be carried out with different levels of randomness, allowing for more realistic treatment of uncertainty to be incorporated into the model outputs and better understanding of investment behaviour. The model outputs many metrics on the electricity market and individual plant that enables the policy impacts to be interpreted. Included in the outputs is a cost-benefit analysis, which includes distributional analysis, where transfers from consumers to producers can be observed.
10. The DDM therefore enables analysis to be carried out of policy impacts given a range of different future scenarios, allowing DECC to consider and compare the estimated impacts of potential policies on the electricity market.

Peer review

11. The model has been peer reviewed by external independent academics to ensure the model is fit for the purpose of policy development. Professors David Newbery and Daniel Ralph of the University of Cambridge undertook a peer review to ensure the model met DECC's specification and delivered robust results. The DDM was deemed an impressive model with attractive features and good transparency[42].

Scenario-based analysis

12. Dispatch modelling is sensitive to a number of such assumptions, which influence the capacity and generation mix realised under different scenarios. This outcome therefore represents a specific state of the world and is not intended to predict or forecast the future.

Limitations of the modelling

13. There are limitations to the modelling, for example the model assumes perfect foresight of demand. This means that the model finds that the economically efficient capacity level is close to zero. In practice demand is uncertain and the risks to building too little are much greater than the risks of building too much, so the economically efficient capacity level is higher in reality.

Capacity Market

14. To capture the effect of capacity agreements, both the allocation process (auction) and the effect on the wholesale electricity market have been modelled.
15. 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. Low-carbon plant in receipt of payment through the RO and CfD is not eligible for capacity payments as they are already supported.
16. The bid prices for each generator are calculated based on the required additional revenue to cover their operating costs, extend the plant lifetime or build a new plant.
17. 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

[42] The Peer Review report, 'Assessment of LCP's Dynamic Dispatch Model for DECC' is available at http://www.decc.gov.uk/assets/decc/11/about-us/economics-social-research/5427-ddm-peer-review.pdf

credits in the Electricity Market Reform modelling. From this ‘stack’, the auction clearing price for each year is calculated, along with plant that are awarded a contract.

18. The key parameters for a modelled CM are:

- For delivery years 2018/19 onwards, the volumes of capacity procured by the central buyer are sufficient to deliver 3 hours lost load per year. This is open to all eligible capacity and there is no differentiation based on flexibility.
- CfD and RO-funded plant are assumed to not receive capacity payments, although their capacity credit is taken into account when setting the level of capacity to contract for.
- The model awards 1-year agreements for existing plant and fifteen-year agreements 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 offer their capacity factors into the auction.
- All plant operating under the Limited Lifetime Opt-out (LLO) mechanism must close in 2023.

Annex B: 2016 Interim Fossil Fuel Price Assumptions (Coal and Gas Price Assumptions)

Given the sharp declines in coal and gas prices during 2015 we produced an interim update of DECC's gas and coal price assumptions in January 2016. These update the short and medium term elements for recent spot and forward coal and gas market movements. The long term price assumptions, which reflect evidence on long run fundamentals, have not been updated in this interim update although we have slowed the pace of market adjustment to long run price levels. The full annual update of DECC's fossil fuel price assumptions will be published in the autumn.

Table 1: Interim DECC Gas FFPA			
p/therm	Central	Outturn	2015 Published Central
2015 prices			
2010		46	
2011		60	
2012		63	
2013		70	
2014		51	
2015		43	47
2016	32		48
2017	32		49
2018	32		49
2019	31		49
2020	30		52
2021	34		55
2022	38		58
2023	41		61
2024	45		64
2025	49		67
2026	53		68
2027	57		68
2028	60		68
2029	64		68
2030	68		68
2031	68		68
2032	68		68
2033	68		68
2034	68		68
2035	68		68
2036	68		68
2037	68		68
2038	68		68
2039	68		68
2040	68		68

Table 2: Interim DECC Coal FFPA			
USD/tonne	Central	Outturn	2015 Published Central
2015 prices			
2010		101	
2011		130	
2012		97	
2013		85	
2014		77	
2015		56	60
2016	44		59
2017	41		60
2018	42		64
2019	50		67
2020	53		69
2021	56		72
2022	60		75
2023	63		77
2024	67		80
2025	70		83
2026	73		84
2027	77		84
2028	80		85
2029	84		86
2030	87		87
2031	87		87
2032	87		87
2033	87		87
2034	87		87
2035	87		87
2036	87		87
2037	87		87
2038	87		87
2039	87		87
2040	87		87