Title: Electricity Market Reform – Capacity Market	Impact Assessment (IA)
	Date: 04/09/2014
IA No: DECC0151	Stage: Final
	Source of intervention: Domestic
Lead department or agency: DECC	Type of measure: Secondary legislation
	Contact for enquiries: Alex Parker alex.parker@decc.gsi.gov.uk

Summary: Intervention and Options

RPC:N/A

Cost of Preferred (or more likely) Option				
Total Net Present Value	**Business Net Present Value**	**Net cost to business per year** (EANCB in 2009 prices)	**In scope of One-In, Two-Out?**	**Measure qualifies as**
£0.3bn	£1.0bn		No	Tax and Spend

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

Over the next twenty years our electricity generation mix will move away from fossil fuel generation and towards more intermittent and less flexible generation. The UK faces very rapid closure of existing capacity as older, more polluting, plant go offline. There is a significant risk that the market will no longer deliver an adequate level of security of electricity supply as it has done historically, principally because potential revenues in the energy-only market may no longer incentivise sufficient investment in capacity. This is the 'missing money' problem and may be caused by:

1. The electricity price not reflecting the true cost of system balancing actions when there is scarcity. Ofgem's announced "cash-out" reforms will go some way to addressing this.
2. The lack of a liquid forward market to build capacity on the basis of expected scarcity rents. This can be due to investor concerns that the Government/Regulator would not let parties earn "scarcity rents".

There are additional market failures due to barriers to entry and from reliability being a quasi-public good. A Capacity Market reinforces energy market signals to ensure there will be sufficient capacity to meet demand.

What are the policy objectives and the intended effects?

The high level objectives of a Capacity Market are:

- **Security of electricity supply**: to incentivise sufficient investment in capacity to ensure security of electricity supply;
- **Cost-effectiveness**: to implement changes at minimum cost to consumers
- **Avoid unintended consequences**: to minimise design risks and complement the decarbonisation agenda

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

The lead policy option, to mitigate risk to electricity security of electricity supply, is a Capacity Market, which was identified in a previous Impact Assessment (IA) published in November 2012. The Cost Benefit Analysis (CBA) and prices and bill impacts have been updated in subsequent IAs (May 2013, October 2013, June 2014).

This IA provides a further update to the CBA and prices and bill impacts, primarily to reflect the advice given by National Grid (and subsequent decision by Secretary of State) regarding target capacity for the forthcoming Capacity market auction, due to take place in December 2014. The annexes to this IA set out the analysis supporting the detailed policy choices that have been made around the design of the Capacity Market. The analysis includes sensitivities on the Value of Lost Load (VoLL) and decarbonisation trajectories.

Will the policy be reviewed? It will be reviewed. **If applicable, set review date:** See Section 10

Does implementation go beyond minimum EU requirements?			**N/A**		
Are any of these organisations in scope? If Micros not exempted set out reason in Evidence Base.	**Micro** No	**< 20** No	**Small** No	**Medium** No	**Large** No
What is the CO2 equivalent change in greenhouse gas emissions? (Million tonnes CO2 equivalent)			**Traded:** **-3 $MtCO_2$**	**Non-traded:**	

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: [signature] Date: 6/9/14

Summary: Analysis & Evidence

Lead Policy Option

Description: Administrative Capacity Market

FULL ECONOMIC ASSESSMENT

Price Base Year 2012	PV Base Year 2012	Time Period Years 19	Net Benefit (Present Value (PV)) (£m)		
			Low: 30	High: 930	Best Estimate: 350

COSTS (£m)	Total Transition (Constant Price)	Years	Average Annual (excl. Transition) (Constant Price)	Total Cost (Present Value)
Low	N/A	-	N/A	**N/A**
High	N/A		N/A	**N/A**
Best Estimate	N/A		N/A	**420**

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

1. **Energy system costs**: These include costs from building additional capacity and the associated impacts on fuel and carbon costs. The impact on energy system costs has a PV to 2030 of £264million. Distributional analysis shows that this cost is largely borne by consumers through electricity bills.
2. **Business administrative costs** have an estimated PV to 2030 of £112million.
3. **Institutional costs** for a central body to procure capacity for the Capacity Market – with an estimated PV of £41million.

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

The cost of the Capacity Market could differ from the modelled effects according to:

- Whether the Capacity Market auction is illiquid. Gaming is more likely to occur if there is not sufficient competition in the auction. This may lead to generators bidding in to the auction at a level above their true cost.
- Whether generators take account of the potential scarcity rents when setting a price in the Capacity Market
- Whether the optimal level of capacity is contracted for

BENEFITS (£m)	Total Transition (Constant Price)	Years	Average Annual (excl. Transition) (Constant Price)	Total Benefit (Present Value)
Low	N/A	-	N/A	**450**
High	N/A		N/A	**1,300**
Best Estimate	N/A		N/A	**760**

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

A Capacity Market incentivises additional capacity which reduces the likelihood of blackouts and voltage reductions. This reduction in energy unserved is valued at £762million. However, a small change to assumptions, such as a change to the assumed level of demand or VoLL can significantly change expected benefits.

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

A Capacity Market has a number of significant non-monetised benefits (discussed further in Section 7):

- A Capacity Market provides a more predictable revenue stream for capacity providers which can lower financing costs for new capital
- There may be gaming opportunities in the energy-only market. In particular, generators may withhold energy in order to drive up wholesale prices. A Capacity Market has potential to reduce these gaming opportunities by increasing penalties on generators that are unavailable at times of system stress.

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

The first capacity auction is run in 2014, with a delivery year of 2018/19. In the capacity auction generators bid in the true cost of providing additional capacity (modelled as the level of support they need in addition to electricity market rent to provide capacity). Providers are entitled to keep any scarcity rents they earn in the energy market. Energy prices are assumed to rise up to £6,000/MWh at times of lost load. We have assumed a VoLL of £17,000/MWh. In the High Net Benefit Scenario we assume a £30,000 VoLL, and in the Low Net Benefit Scenario we assume a £10,000/MWh VoLL. For further detail, see section 6.

In line with previous IAs for the Capacity Market (and EMR) a decarbonisation trajectory of 100gCO_2/kWh in 2030 is assumed. The EMR package modelled includes a low-carbon instrument (the CfD) and a Capacity Market, combined with an Emissions Performance Standard (EPS). The analysis includes existing policies such as the Renewables Obligation (RO) and support for early-stage CCS projects.

BUSINESS ASSESSMENT

Direct impact on business £m:			In scope of OIOO?	Measure qualifies as
Costs: 550	**Benefits: 1,600**	**Net: 1,000**	No	N/A

Evidence Base (for summary sheets)

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1 Background

1.1 This IA provides an update to analysis of the impact of the Capacity Market. It supports the laying in Parliament of the Electricity Capacity Regulations 2014 and the Capacity Market Rules 2014.[1] This IA provides the analytical justification for the detailed design choices made.

1.2 Previous IAs for the Capacity Market – primarily December 2011[2], November 2012[3], May 2013[4], October 2013[5] and June 2014[6] – have analysed the policy options that would best deliver our security of electricity supply objective. The key conclusions from these previous impact assessments are:

- A Capacity Market is the preferred instrument to mitigate security of electricity supply risks compared to alternatives, including a strategic reserve and doing nothing.[7]
- An Administrative Capacity Market is the preferred form of the capacity market compared with a reliability option.[8]

Modelling changes since June 2014

1.3 Following the last Capacity Market IA in June 2014 there has been a change to the modelling:

- DECC's Dynamic Dispatch Model (DDM) has been updated so that 53.3GW of capacity is targeted for the first delivery year (2018/19).[9] This is in line with the final policy decision on target capacity, made by the Secretary of State in June 2014.[10] For all other delivery years (2019/20 onwards) the modelling of target capacity remains unchanged.

Modelling changes since October 2013

1.4 As outlined in the June 2014 IA, following the Capacity Market IA in October 2013 a number of modelling changes were made:

[1] https://www.gov.uk/government/policies/maintaining-uk-energy-security--2/supporting-pages/electricity-market-reform
[2] https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/42797/3883-capacity-mechanism-consultation-impact-assessment.pdf
[3] https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/66039/7103-energy-bill-capacity-market-impact-assessment.pdf
[4] https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/197911/capacity_market_ia.pdf
This IA was originally published in January 2013, but was republished in May 2013 alongside the publication of the Energy Bill.
[5] https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/252743/Capacity_Market_Impact_Assessment_Oct_2013.pdf
[6] https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/324430/Final_Capacity_Market_Impact_Assessment.pdf
[7] This decision was first presented in the December 2011 Technical Update to EMR (http://www.decc.gov.uk/assets/decc/11/consultation/cap-mech/3883-capacity-mechanism-consultation-impact-assessment.pdf).
[8] An Administrative Capacity Market is one in which capacity providers receive a payment for offering capacity which is available when needed, but are able to keep their energy market revenues. Under a Reliability Market, capacity providers receive a payment for offering capacity which is available when needed, but are required to pay back any scarcity rents earned in the energy market.
[9] This is the main change since the June 2014 IA. For the June 2014 IA, the DDM calculated the target capacity that would meet a loss of load expectation of 3 hours per year in 2018/19. This IA also corrects any typographical errors in the June 2014 version of the IA.
[10] https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/324973/20140627_Edward_Davey_to_Nick_Winser_and_Mark_Ripley.pdf

- The DDM has been updated to model National Grid's Supplemental Balancing Reserve (SBR).[11] The modelling assumes that plant included in the SBR can only participate in the wholesale energy market in exceptional circumstances.

- The DDM has been updated to reflect the latest policy on Carbon Price Support, announced as part of Budget 2014.[12]

- Plant that opt-out under the Industrial Emissions Directive have a limit placed on the number of hours for which they can generate.[13] The updated modelling allows opt-out plant the option to hold back a nominal number of hours in order to participate in the Capacity Market.

- The updated modelling also allows plant the option to increase their capital expenditure in order to increase the lifetime of their plant by 10 years.

- For the October 2013 Capacity Market IA, the modelling assumed that the bid of existing plant is only affected by costs and revenues in the delivery year for which the plant was bidding. The DDM has now been updated so that existing plant take account of costs and revenues in other years. The DDM has also been updated so that if an existing plant is unsuccessful in an auction for a delivery year, the plant closes immediately, rather than closing in the delivery year.

- The DDM has been updated so that the assumed Transmission Network Use of System (TNUoS) charges vary by location of plant, as opposed to a single TNUoS charge across all plants regardless of location.

- Previously, the modelling did not allow new build small scale Open Cycle Gas Turbine (OCGT) to bid into the Capacity Market. This is because it was expected that new build small-scale OCGT would bid in to the auction at a level that would be uncompetitive. The modelling has now been updated so that this type of plant can bid in to the auction; however, this has made no difference to the basecase results, as the modelling does indeed show that new build small-scale OCGT bid in above the clearing price.

- The modelling now assumes greater contribution from interconnection at times of system stress. It was prudent to take a conservative approach for previous modelling, given the uncertainty on whether prices in the GB electricity market would reflect periods of scarcity and whether the direction of interconnector flows would be efficient (i.e. flowing from low-price to high-price markets). Whilst still recognising uncertainty in these areas, we now think it is credible to increase the amount of capacity assumed from interconnectors. This is because GB electricity prices are expected to become more responsive to tight margins, following confirmation of Ofgem's proposals on cash-out reform and increased certainty about the way the European Target model will work, in light of the initial evidence about the price response of GB interconnector flows after the coupling of the GB market with North West Europe earlier this year.[14]

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[11] The SBR will be targeted at generating plant that would otherwise be closed or mothballed. The purpose of the SBR (and the Demand Side Balancing Reserve) is to mitigate short term security of electricity supply risks. http://www2.nationalgrid.com/Media/UK-Press-releases/2014/National-Grid-to-contract-for-new-balancing-services/

[12] https://www.gov.uk/government/publications/carbon-price-floor-reform

[13] https://www.gov.uk/government/publications/regulating-large-combustion-plants-industrial-emissions-directive

[14] For further detail see the "Contribution of Interconnection" section below (paragraph 1.7 onwards).

- The assumed amount of demand side response (DSR) capacity has now been aligned to National Grid's 2014 Future Energy Scenarios, which incorporates a comprehensive engagement process with industry.[15] We now use the midpoint of Grid's scenarios, which assumes 2.6GW in 2019.

- Following the Electricity Market Reform Consultation there have been a number of changes to the Capacity Market policy.[16] As a result, the modelling has been updated to reflect 15 year contract lengths for new build capacity, rather than 10. Net cost of new entry (Net CONE) has also been updated from £29/kW to £49/kW.[17]

- The number of businesses assumed to participate in the capacity market has been reduced. As a result the estimated business administrative costs have reduced from a PV of £231million to a PV of £112million.[18]

- The estimate of institutional costs has been updated. As a result, the institutional costs have increased from an estimated PV of £32million to a PV of £41million.[19]

- A number of modelling changes were made between the Capacity Market IA in October 2013 and the Electricity Market Reform Final Delivery Plan IA.[20] These modelling changes can be found in Annex H of the Final Delivery Plan IA.[21]

1.5 The effect of these changes has been to slightly change the estimated benefit of the Capacity Market from increased reliability of electricity supply, leading to an overall benefit of **£0.3bn up to 2030** (in these latest estimates) compared to an estimated net benefit of £0.2bn (in October 2013), and £0.4bn in June 2014.

Table 1: **Change in Net Welfare (NPV) – Capacity Market, comparison of October 2013 IA and latest figures (emissions intensity in 2030 = 100gCO_2/kWh)**

	NPV, £bn (2012-2030, real 2012 prices)		
	October 2013	**June 2014**	**August 2014**
Capacity market	0.2	0.4	0.3

Source: DECC modelling

[15] National Grid's DSR assessment is based on Element Energy's paper "Demand Side Response in the non-domestic sector" and additional analysis, which was published in the 2014 UKFES document on 10th July 2014. http://www.element-energy.co.uk/wordpress/wp-content/uploads/2012/07/Demand-Side-Response-in-the-non-domestic-sector.pdf
[16] https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/255254/emr_consultation_implementation_proposals.pdf
[17] For more details see Annexes C and D
[18] The number of businesses assumed to participate in the Capacity Market is now based on the number of major power producers as listed in Table 5.11 of DUKES (2013), plus an estimated number of non-major power producers with more than 5MW of capacity (a subset of 'Other power stations' in Table 5.11). This gives a range of 51 to 120 businesses. The midpoint of this range has been used to calculate the business administrative cost. For the October 2013 Capacity Market IA the assumed range was 77 to 277 businesses.
https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/254261/ukesi_2013.pdf
[19] Institutional cost estimates include a portion of National Grid's administration costs as the EMR delivery body (those assumed to relate to Capacity Market administration), as well as provisional estimates for the Electricity Settlements Company costs for 2012 – 2016, further details on which are available at:
https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/298354/CFD_Counterparty_and_Electricity_Settlements_Company_operational_costs.pdf
Cost estimates should be regarded as tentative, as the component costs have not yet been fully determined.
[20] https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/288463/final_delivery_plan_ia.pdf
[21] https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/267960/Annex_H_-_Modelling_Assumptions.pdf

1.6 The latest modelling shows **a net increase in the average annual domestic electricity bill of £2 over the period 2016 to 2030** (in 2012 prices). This is equivalent to a 0.3% average increase in domestic electricity bills. Gross capacity payments are estimated to increase the average annual domestic electricity bill by £14 over the period 2016 to 2030 (in 2012 prices). However, the Capacity Market is also estimated to lead to a reduction in wholesale prices, due to a greater amount of generating capacity being available and dampening the response of wholesale prices to potential tightening in security of electricity supply conditions. The table below shows the impact of a Capacity Market on the bills of different groups – domestic consumers, non-domestic consumers and energy-intensive industries (EIIs).

Table 2: **Electricity Bill Impacts**

Average annual bills, in 2012 prices	**Typical bill without Capacity Market**	**Change with Capacity Market (%)**
Domestic, (£)		
2011-2015	567	0%
2016-2020	590	1%
2021-2025	619	1%
2026-2030	716	-1%
Non Domestic (£000)		
2011-2015	1,100	0%
2016-2020	1,300	1%
2021-2025	1,400	2%
2026-2030	1,600	1%
Energy Intensive Industry, (£000)		
2011-2015	7,900	0%
2016-2020	10,100	2%
2021-2025	11,800	3%
2026-2030	12,800	1%

Source: DECC modelling

Contribution of Interconnection

1.7 Interconnection to other electricity markets can contribute to GB security of electricity supply by allowing other markets to supply energy at times of stress through electricity markets and so reducing the need to build domestic backup plant. We also acknowledge that interconnection can contribute to GB security of electricity supply through bilateral contracts that the system operator can call upon in emergencies, however this is considered as an absolute last resort measure and not considered in deciding what capacity to procure in a capacity market.

1.8 Estimating the flow of interconnectors at times of system stress is very difficult due to uncertainty in GB and across Europe of power prices, coincidence of system stress across markets and how market coupling will work. Moreover, historical data are not likely to be a good indicator of the future given the rapidly changing power markets across GB and Europe.

1.9 The October 2013 Capacity Market IA assumed that net 0GW of interconnection was available at times of system stress, consisting of 0.75GW imports from continental Europe and 0.75GW exports to Ireland. It was prudent to take this conservative approach at the time, given uncertainty on whether prices in the GB electricity market would adequately reflect periods of scarcity and whether the direction of interconnector flows would be efficient (i.e. flowing from low-price to high–price markets). Since then, DECC has reviewed the policy developments and evidence in relation to interconnection.

1.10 However, many uncertainties still remain – for example, how the European Target model will continue to develop, what future interconnection will be built and how flows may respond to tight margins (for which there is a lack of historical evidence). Based on the developments listed above, we believe that it is reasonable to revise our assumptions on interconnection to allow for a larger contribution from the continent at times of system stress, whilst recognising the uncertainties around this and a range of potentially credible alternative views.

1.11 Our revised assumptions are primarily based on analysis for DECC by Poyry.[22] This analysis suggests that, in an efficient market, we can expect to be importing electricity through interconnectors at times of stress – equivalent to around 75% of the total existing capacity of interconnectors to the continent. Poyry also show that imports from Ireland are possible, but we think it is prudent to continue to assume full exports over the interconnectors to Ireland. This has been the case historically, and market coupling with Ireland is still yet to be implemented. There is currently 3GW of interconnector transmission capacity to the continent and 750MW to Ireland. Therefore, in an efficient market, with current interconnection capacity, we have assumed that it is possible to import up to 1.5GW of capacity (i.e. 75% of 3GW imports and 0.75GW of exports) through existing interconnectors at times of stress.

1.12 In assessing the potential for future interconnection, we used the same Poyry analysis to estimate an average de-rating factor of 70%[23]. The modelling assumes that 2GW of further interconnection will have connection agreements by the time of the first delivery year (2018/19), which gives an additional 1.4GW of potential interconnection by 2018/19. However, we recognise that the actual commissioning dates for these future interconnection projects are still very uncertain. Adding this 1.4GW to the existing derated capacity of 1.5GW gives 2.9GW in total. Assuming that a further 1.4GW of interconnector capacity will be built by 2030, combined with a derating factor of 70%, the total amount of assumed interconnection increases further, to 3.9GW.

1.13 As outlined above, the contribution of interconnection towards future security of electricity supply is still very uncertain. The updated modelling for this IA takes account of the advice given by National Grid and subsequent decision by Secretary of State regarding target capacity for the first delivery year (2018/19). This was based on an assumption of net zero contribution from interconnection at times of system stress in that year, leading to a recommended amount of capacity to procure of 53.3GW in 2018/19.

[22] "Impact of EMR on Interconnection, December 2012, Poyry http://poyry.co.uk/sites/poyry.co.uk/files/poyry_report_on_impact_of_cm_on_interconnection.pdf

[23] The difference with the derating factor assumed for existing interconnection is due to an expansion in the number of countries connected to in future interconnection scenarios

2 Overview

2.1 The Government has taken powers in the Energy Bill to run a Capacity Market and has consulted on the secondary legislation that sets out the detailed rules for how the Capacity Market will function. The Capacity Market will incentivise sufficient reliable capacity (both supply and demand side) to ensure a secure electricity supply, even at times of peak demand.

2.2 This IA presents an appraisal of the lead option for mitigating security of electricity supply risks in the GB electricity market – a Capacity Market. The analysis presented in this IA is based on a standardised set of assumptions, including technology costs and electricity demand at the time the analysis was undertaken. These assumptions are set out in more detail in Annex G.

2.3 The objective of the Capacity Market is to ensure that an adequate level of security of electricity supply is delivered in a way that is cost-effective and complementary to decarbonisation policies. Over the coming years, the UK electricity market will undergo profound changes. The UK faces very rapid closure of existing capacity as older, more polluting, plant go offline and we will see a significant rise in intermittent and less flexible generation to support our climate change objectives. We also expect overall demand for electricity to increase in the long term as a result of the electrification of our transport and heating systems.

2.4 If the existing energy market worked perfectly, this would not be a problem as investors would bring forward capacity on the basis of the high prices they could earn at times of scarcity. However, imperfections in the market could mean that the market fails to bring forward sufficient capacity. Electricity prices do not currently reflect the value of scarcity due to how imbalance ("cash-out") prices in the balancing mechanism are calculated. Ofgem have recently announced their final policy decision to reform cash-out.[24] However, even with cash-out reform, there are other issues which may prevent investors bringing forward sufficient capacity. For example, industry may not feel able to invest if they are concerned that the Government/Regulator would intervene to prevent parties earning "scarcity rents".

2.5 A Capacity Market is an appropriate way to mitigate the risk of voltage reductions ("brownouts") and controlled load shedding ("blackouts") due to the energy market not bringing forward the economically optimal amount of capacity. It does this by contracting for the appropriate level of capacity. This ensures there is sufficient reliable capacity to meet demand, for example during winter anti-cyclonic conditions when demand is high and wind generation is low for a number of days.

2.6 DECC's latest energy system modelling supports Ofgem's assessment that capacity margins are likely to tighten in the years ahead.[25] DECC's analysis suggests that a failure to intervene could lead to a significant increase in risks in the 2020s as the level of intermittency is greater and as a number of existing plant retire. However, modelling is inevitably uncertain given the wide potential ranges for factors such as demand, weather conditions, the reliability of plant, and impact of announced changes to the cash-out regime.

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[24] https://www.ofgem.gov.uk/publications-and-updates/electricity-balancing-significant-code-review-final-policy-decision
[25] http://www.ofgem.gov.uk/Markets/WhlMkts/monitoring-energy-security/elec-capacity-assessment/Pages/index.aspx

2.7 According to this latest assessment, generation capacity is expected to fall over the next couple of years (between 2-5% for the winter of 2015/16) due to expected plant retirements, before recovering somewhat toward the end of the decade as Carrington (Q1 2016) and various renewable projects come on-line. Since then, National Grid has announced its intention to buy up to 1,800MW of additional balancing services for winter 2015/16.[26] This will effectively add an additional 3 percentage points to the derated capacity margin to help mitigate short-term security of electricity supply risks until the Capacity Market is in place later in the decade.

2.8 The Government will run the first Capacity Market auction in December 2014, for delivery of capacity in the year beginning in the winter of 2018/19, following state aid approval[27].

2.9 Our base case analysis shows that a Capacity Market is expected to have a net benefit of £0.3bn relative to a scenario where the energy price is able to rise to £6,000/MWh but not to the full value of customers' VoLL (estimated at £17,000/MWh).[28] However, the benefits of a Capacity Market could be even greater if it succeeds in reducing the risk of investing in new or existing capacity by giving investors a steady capacity payment in place of uncertain scarcity rents in the energy market.

2.10 However, the security of electricity supply outlook is uncertain as it is difficult to predict capacity margins with precision or to estimate the security of electricity supply impacts from tighter margins. Small changes in assumptions can lead to significant changes in outcomes. The overall conclusion from the analysis is therefore that a Capacity Market is a sensible precaution against the risk of market failures in the energy market leading to inadequate levels of security of electricity supply.

2.11 The Capacity Market is assessed with quantitative and qualitative analysis. The quantitative analysis (Section 6) shows that this option has a net benefit of £0.3bn. The qualitative analysis (Section 7) looks at wider impacts, while Section 8 concludes.

2.12 The annexes give details around our modelling approach as well as setting out the analysis underpinning some of the more detailed design issues that have been considered, namely:

a) The choice of auction format;
b) The timeline for procuring capacity;
c) The choice of agreement length;
d) The demand curve;
e) Eligibility rules for participation in the Capacity Market;
f) The level of penalties and when they are applied; and
g) Energy system modelling

[26] http://www2.nationalgrid.com/Media/UK-Press-releases/2014/National-Grid-to-contract-for-new-balancing-services/
[27] https://www.gov.uk/government/news/radical-reforms-to-electricity-market-pass-into-law
[28] "The Value of Lost Load (VoLL) for Electricity in Great Britain", July 2013, London Economics https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/224028/value_lost_load_electricty_gb.pdf Note that there is significant uncertainty around the estimate of VoLL. For this reason we have carried out sensitivity analysis, with VoLL estimates of £10,000/MWh and £30,000/MWh (see section 6).

3 Objectives

3.1 As set out in the previous IA, the high level objectives of a Capacity Market are:

i) Security of electricity supply**:** to incentivise sufficient investment in generation and non-generation capacity to ensure security of electricity supplies.

ii) Cost-effectiveness**:** to implement changes at minimum cost to consumers.

iii) Avoid unintended consequences**:** to minimise design risks and ensure compatibility with other energy market policies, including decarbonising the power sector.

iv) Deliverable for 2014 auction date**:** Given the risks to security of electricity supply as plants retire over this decade and the potential for an investment hiatus until a Capacity Market is implemented, the Government will run the first auction in 2014; it is therefore important that the chosen Capacity Market can be implemented in time for a first auction in 2014.

4 Rationale for Intervention

Introduction

4.1 Electricity markets are different from other markets in a number of ways, two of which are particularly significant: capacity investment decisions are very large and infrequent; and there is currently a lack of a responsive demand side as consumers do not choose the level of reliability of supply they are willing to pay for (as load shedding occurs at times of scarcity on a geographic basis rather than according to suppliers, and as domestic consumers do not respond to real time changes in the price of electricity). Smart Meters, which are expected to be rolled out by 2019, should help to enable a more responsive demand side but it is anticipated that it would take time for a real-time responsive market to evolve.

4.2 While the market has historically delivered sufficient investment in capacity, the market may fail to bring forward sufficient capacity in the future. The UK faces very rapid closure of existing capacity as older, more polluting, plant go offline and as the power system decarbonises. The decarbonisation of the power sector means that thermal plant can expect to run at lower load factors in future and so need to recover a greater proportion of their fixed costs through scarcity rents at times of stress. This increases risks for investment in thermal capacity exactly at a time when the UK needs significant investment in new gas build to replace the existing ageing fleet. So while there have always been risks that an energy-only market would fail to invest sufficiently in new capacity, these risks have become significantly more material and so necessitate intervention to ensure security of electricity supply.

4.3 The market may also fail to provide incentives for capacity built to be sufficiently reliable, flexible and available when needed. A Capacity Market mitigates the risk that an energy-only market fails to deliver sufficient incentives for reliable and flexible capacity.

Market failures in the energy market

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

4.5 The principal market failure is that **reliability is a quasi-public good**. It is non-excludable in the sense that customers cannot choose their desired level of reliability, since the System Operator cannot selectively disconnect customers. Therefore, it can be expected that reliability will not be adequately provided by the market.

4.6 In theory, this problem is addressed in an energy-only market by allowing prices to rise to a level reflecting the average VoLL (i.e. the price at which consumers would no longer be willing to pay for energy) and allowing generators to receive scarcity rents.

4.7 However, in reality an energy-only market may fail to send the correct market signals to ensure optimal security of electricity supply and to enable investors to obtain project finance for building new capacity. This is commonly referred to as the problem of '**missing money**', where the incentives to invest are reduced, due to the three reasons below:

- Current wholesale energy prices do not rise high enough to reflect the value of additional capacity at time of scarcity. This is due to the charges to generators who are out of balance in the Balancing Mechanism ("cash-out") not reflecting the full costs of balancing actions taken by the System Operator (such as use of reserve capacity or customer disconnections).

- Stress events are unlikely to occur frequently. With an increasingly decarbonised power sector, investors face uncertainty about running hours and so will be increasingly reliant on recovering fixed costs through infrequent and uncertain scarcity rents.

- At times when the wholesale energy market prices peak to high levels, investors are concerned that the Government/regulator will act on a perceived abuse of market power, for example through the introduction of a price cap.

4.8 The third problem is exacerbated if there are significant **barriers to entry**, effectively restricting the number of participants in the wholesale electricity market. As margins become tighter and prices more volatile in the future, market participants may have more opportunities to withhold supply to drive up prices – particularly so as demand is inelastic in response to short-term shocks and so there are potentially significant gains from withholding at times of scarcity. This could result in a greater likelihood of gaming in the energy market and difficulties in differentiating such gaming from legitimate market-driven prices, which would increase the risk that the Government may want to intervene in the wholesale market to cap prices.

4.9 This has not previously been a significant concern as prices historically have not risen above £938/MWh as a result of excess capacity on the system depressing wholesale market prices.[29] The excess capacity arose due to a number of factors that no longer hold: most of this capacity was built prior to the introduction of an energy-only market in 2001, the decline in gas prices in the 1990s under the “dash for gas” made it profitable to invest in new gas plant in this period while there was still sufficient coal capacity, and the financial crisis in 2008 and the subsequent fall in rate of economic growth significantly supressed demand for electricity. In the future, analysis suggests that prices could need to rise to up to £10,000/MWh (or even higher) for short periods to allow flexible plant to recover investment. Investors are concerned that Government or the regulator would intervene if this were to happen. The perception of this regulatory risk could increase ‘missing money’ and under-investment.

Does the current electricity market sufficiently value capacity?

4.10 The current electricity market may fail to provide sufficient incentives for investment in new capacity or for existing capacity to be flexible, reliable and available when needed.

4.11 This is due in part to cash-out prices currently failing to reflect the value of capacity at times of scarcity. The main cash-out price is the closest thing to a real-time price in the GB market but has historically failed to reflect scarcity for a number of reasons: the use of reserve capacity is not priced appropriately into cash-out, the System Operator’s actions are averaged when priced into cash-out, the cost of customer disconnections and voltage reductions are not priced at all into cash-out, and there is no real-time market into which parties can sell energy and receive the clearing price.

[29] System buy price on 5th January 2009, settlement period 35. Balancing Mechanism Reporting System (BMRS), http://bmreports.com/

4.12 Historically, the highest cash-out prices have risen to is £938/MWh, although it should be noted that this may also be due to excess capacity on the system. If prices could only go to around £1,000/MWh in scarcity events it would imply that the current price is far from cost-reflective. A £1,000/MWh price during a controlled load shedding is likely to be significantly less than the amount consumers would be willing to accept to avoid being disconnected.

4.13 Ofgem's final policy decision from the Electricity Balancing Significant Code Review included reforms to allow cash-out to rise to a price of £6,000/MWh at times of stress, having a single marginal price and pricing the Short Term Operating Reserve (STOR) into cash-out. This will go some way to addressing the missing money that is currently present in the energy market. This should mean that providers will have less need to recover their fixed costs through the Capacity Market and the price in the Capacity Market auction should be lower than it would be without the cash-out reform.

4.14 However, this price is still considerably lower than our estimate of VoLL (£17,000/MWh). Due to the significant uncertainties around estimating the precise magnitude of VoLL, a price of £6,000/MWh still may not be sufficient to provide optimal incentives for investment in new flexible generating capacity.

4.15 Even if cash-out were reformed to allow prices to reach levels which reflect the full cost of energy in scarce periods, there are still significant concerns around the ability of an energy-only market to deliver sufficient levels of investment in capacity. This concern about "missing money" will become increasingly significant as the power sector decarbonises and gas plants runs at lower load factors – recovering a higher proportion of their fixed costs through scarcity rents.

4.16 If the market worked perfectly, this would not be a problem as operators of flexible capacity would have sufficient confidence that prices would spike to such an extent that would enable them to cover their costs. However, industry may not feel able to invest if they cannot attain finance on the basis of uncertain scarcity rents or if they do not have confidence that the regulated market will be allowed to operate in an unconstrained way. As such, the level of flexible capacity required may not come forward, potentially resulting in controlled load shedding/voltage control and an increase in wholesale prices and consumer bills at times of high demand and low wind.

Exit Criteria for the Capacity Market

4.17 This IA identifies a number of market failures present in the energy-only market that justify the introduction of a Capacity Market. However, as noted, an energy-only market can under certain conditions provide sufficient incentives for investment in capacity – even in a decarbonised power system where thermal plant runs at very low load factors. The Capacity Market is intended to be a transitional measure that will complement measures to strengthen energy market incentives for investment and so allow exit from the mechanism. However, it is expected that the Capacity Market will be in place for at least fifteen years and further for as long as additional capacity remuneration is needed to ensure security of electricity supply.

4.18 Analysis suggests remuneration through the Capacity Market would become less necessary in future at the point that two current features of the energy market (lack of liquidity and an active demand side) had been adequately addressed.

4.19 Development of greater demand side response (DSR)**:** The lack of an active demand side in the energy market leads to greater price volatility (as prices in a competitive market jump from the short run marginal cost of the peaking plant to VoLL) and potential for abuse of market power for parties withholding generation at times of stress. So the development of a sufficiently active DSR in the energy market would help to enable a return to an energy-only market.

4.20 However, it may take a long time for a fully active DSR to develop. In particular, it would require greater infrastructure for DSR (such that households are able to turn down load in response to real-time price signals) and it would require that demand is sufficiently responsive (for instance such that it would be rare for prices to rise above £1,000/MWh even in the event of scarcity).

4.21 Improvements to liquidity: As set out earlier, reform of balancing arrangements could help to mitigate concerns around "missing money" in the energy market. However, it is unlikely that cash-out reform would have a large impact in the short term, due to the gradual implementation of the reforms, but is more likely to affect investment decisions in the medium to longer term as the price signals work through the system.

4.22 In theory, as this happens, prices should reduce towards zero in the Capacity Market auction. However, this will only happen if investors are able to invest on the basis of uncertain scarcity rents. The move to a single marginal spot price for energy (and possibly a balancing market) could help create a robust reference price around which people could trade financial options (as occurs in Australia and America and as used to happen in GB under the pool). This would involve suppliers paying a steady payment to generators in exchange for a financial hedge against price spikes in the spot market. A liquid options market could enable suppliers and generators to hedge the risk of volatile prices and so help investors build new plant on the basis of uncertain scarcity rents.

4.23 Investment in Interconnection: A greater degree of interconnection could also help to reduce the role of the Capacity Market in future. Interconnection can help with security of electricity supply in a number of ways:

- It reduces the overall level of investment needed in GB capacity to the extent that interconnected capacity provides security of electricity supply;
- It can increase diversity of supply by connecting GB to markets with different plant and technology mixes.

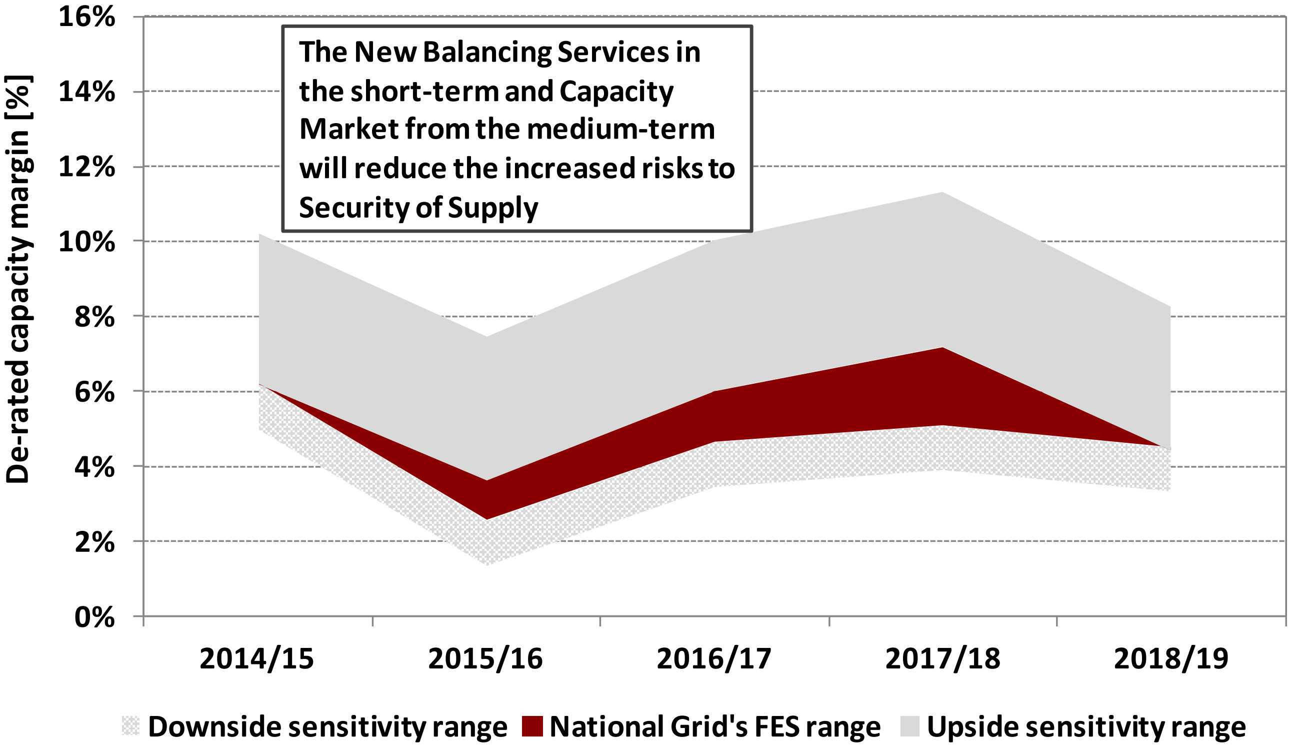
4.24 Given the scale of investment in new capacity needed it is unlikely that greater interconnection alone would enable an exit from the capacity market. However, coupled with more effective energy price signals and/or greater DSR, further investment in interconnection should reduce the level of support needed in the Capacity Market to achieve security of electricity supply.

Security of Electricity Supply Outlook

4.25 We have looked at security of electricity supply risks both in the short term, particularly 2015/16, by when the Large Combustion Plant Directive will have prompted a number of existing coal plants to retire, as well as the longer term security of electricity supply outlook out to 2030 as the power sector decarbonises. The key factors affecting the security of electricity supply outlook are expectations for peak demand, the contribution of interconnection to security of electricity supply, the level of nuclear plant life extensions, and expectations for new build decisions and mothballed plants.

4.26 Ofgem produced its annual Electricity Capacity Assessment Report in June 2014 as part of its statutory obligation to review security of electricity supply.[30] Figure 1 summarises its key findings.

Figure 1: **Ofgem estimates of derated capacity margins**



Source: Ofgem (June 2014)

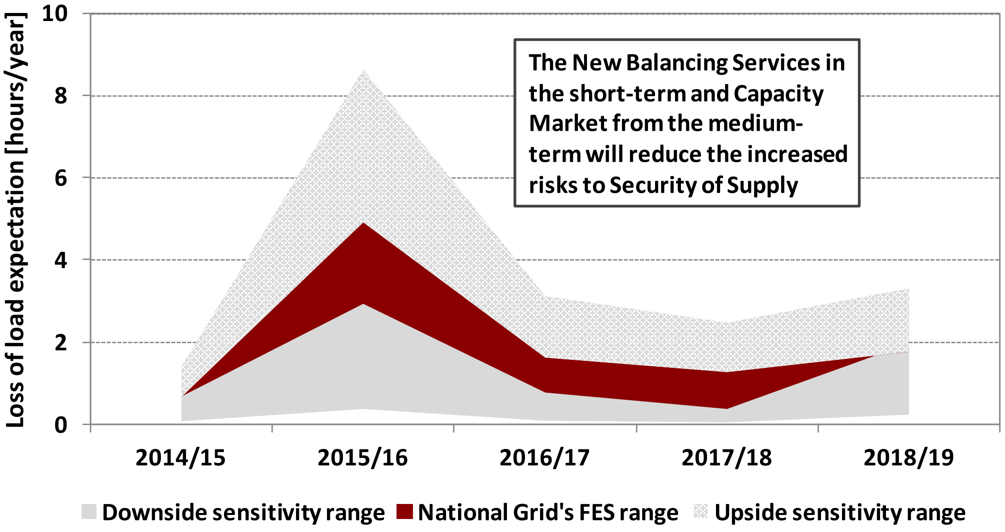
4.27 The report shows that derated margins in the core scenarios (National Grid's Future Energy Scenarios) are expected to decrease from 6 per cent this winter to under 4 per cent in 2015/16, before recovering somewhat toward the end of the decade as Carrington (Q1 2016) and various renewable projects come on line and peak demand falls due to energy efficiency improvements. Given the significant uncertainties around the evolution of both demand and supply, Ofgem has also developed a number of sensitivities. A full list of these and the assumptions which underpin them can be found in their report.[31]

4.28 The derated capacity margins that Ofgem forecast in 2015/16 are similar to the levels experienced in 2005/6. While this was a tight year for National Grid to manage, there were no customer disconnections. We recognise however that the generation mix in 2005/6 is not the same as the mix in 2015/16, implying different risks to security of electricity supply.

[30] https://www.ofgem.gov.uk/ofgem-publications/88523/electricitycapacityassessment2014-fullreportfinalforpublication.pdf
[31] https://www.ofgem.gov.uk/ofgem-publications/88523/electricitycapacityassessment2014-fullreportfinalforpublication.pdf

4.29 While derated margins illustrate trends in the market, they are not a measure of the risk to security of electricity supply. Instead, Ofgem's assessment presents the risks to security of electricity supply using the "Loss of Load Expectation" or LOLE - this represents the number of hours per year in which supply is expected to be lower than demand before any intervention (eg. voltage reduction) by the System Operator. In the Future Energy Scenarios, Ofgem estimates an increase in LOLE from less than 1 hour per year in winter 2014/15 to between 3 and 5 hours per year in 2015/16 as derated margins decrease. The change in LOLE illustrates that small reductions in margins from current levels would result in a significant increase in the risks to security of electricity supply.

Figure 2: **Ofgem estimates of LOLE**



Source: Ofgem (June 2014)

4.30 However, to mitigate this security of electricity supply risk in the years up until the start of the Capacity Market in 2018/19, National Grid's new balancing services will secure extra capacity by keeping otherwise un-economic generators on the system through the Supplemental Balancing Reserve, and – through Demand Side Balancing Reserve - rewarding businesses that offer to do so for reducing their electricity use for short periods when demand is highest.

4.31 While balancing services are different from normal capacity because they remain outside the market and are only for use after all market options have been used, National Grid's plans will in effect keep the chances of controlled disconnections at a level at least equal to or below the level corresponding to the Government's 3 hour LOLE reliability standard.

DECC's electricity system modelling

DECC's modelling of the electricity system is based on DECC's in-house Dynamic Dispatch Model (DDM).

The EMR package modelled includes a low-carbon instrument (the CfD) and a Capacity Market, combined with an Emissions Performance Standard (EPS). The analysis includes existing policies such as the Renewables Obligation (RO) and support for early-stage CCS projects. This IA makes some detailed assumptions about the implementation of these policies, in particular that the 2020 renewables target is met through domestic deployment, that there are two early stage CCS projects.

The modelling makes assumptions about the trajectory for power sector decarbonisation beyond 2020. A decarbonisation trajectory of $100gCO_2/kWh$ in 2030 is used in the modelling in this IA to ensure consistency with previous IAs on capacity mechanisms. Further details on the modelling assumptions are set out in Annex G.

4.32 In our latest analysis using the DDM, derated margins in the base case are estimated to be very low in the 2020s (sustained below 5%). This is largely attributed to the retirement of a significant proportion of conventional thermal plant capacity between now and 2023, and an insufficient amount of reliable base-load generation brought forward to replace this capacity.

4.33 However, long-term projections of capacity margins are highly uncertain because of the difficulties in anticipating, for example, the level of electricity demand, wind patterns, generator reliability and the contribution of interconnectors in periods of system stress. Moreover, the relationship between loss of load expectation and derated capacity margin is not linear.

4.34 The decision to invest in generation capacity in the DECC model is based on the simplifying assumption that investors have perfect foresight of energy demand five years ahead. The consequence of this assumption is that investors can gauge precisely peak demand and build just enough capacity to meet it in most circumstances. In reality, peak demand is uncertain, and so the economically efficient capacity margin is likely to be greater than that under perfect foresight because there is an increased likelihood of energy scarcity and the associated jump in energy price to its scarcity value. Therefore, a perfect energy-only market would be likely to bring forward a higher capacity margin than that forecast by the DECC model without a Capacity Market.

5 Options Appraisal

5.1 The IA published alongside the Energy Bill in November 2012 set out the evidence for the choice of a Capacity Market as the lead policy option to mitigate risks to electricity security of electricity supply.[32] A summary of the evidence informing that decision is presented here, but detailed analysis of other potential options is not included.

Basecase

5.2 The baseline against which we are comparing the options for the Capacity Market assumes that a number of policy options that form part of the Electricity Market Reform package have been implemented, including the FiT CfD, Emissions Performance Standard and Carbon Price Support. It also assumes the Supplemental Balancing Reserve (SBR) and Demand Side Balancing Reserve (DSBR) are in operation between 2014/15 and 2017/18.

5.3 The basecase also has a number of important characteristics:

i. <u>Decarbonisation</u>: As for previous IAs, the basecase assumes that the power sector decarbonises to an average level of 100gCO_2/kWh in 2030. This entails a significant increase in intermittent and less flexible generation (predominantly wind and nuclear).[33]

ii. <u>Retirement of existing plant</u>**:** The UK faces very rapid closure of existing capacity as older, more polluting, plant go offline.

iii. <u>Missing Money</u>**:** We have assumed a wholesale market where prices can rise to a value of £6,000/MWh when there is scarce capacity. This is consistent with Ofgem's announced policy decision to price in involuntary load shedding at £6,000/MWh by 2018.

Capacity Market

5.4 A Capacity Market pays capacity providers for capacity, which is defined as delivering energy when needed. Capacity providers offer capacity into the Capacity Market and, if successful in the auction, receive a capacity payment. They may also be eligible for long-term contracts if they are new plant. At times of system scarcity, when the System Operator is forced to issue load-shedding due to insufficient capacity, any capacity providers that were not generating will be fined an administratively-set penalty.

5.5 The detail of how the Capacity Market will work is set out in the EMR handbook, Electricity Capacity Regulations 2014 and the Capacity Market Rules 2014.[34] However, the high level features of the mechanism are summarised in the box below.

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

[33] Analysis for the Carbon Plan suggests that cost-effective pathways to 2050 include decarbonising the power sector to around 100g CO_2/kWh in 2030. The Government will take a decision on a decarbonisation target for the power sector once the CCC has provided advice on the 5th carbon budget.

[34] https://www.gov.uk/government/policies/maintaining-uk-energy-security--2/supporting-pages/electricity-market-reform

Features of a Capacity Market:

1. **Amount of capacity**: Ministers decide the amount of capacity for which agreements are to be auctioned based on analysis from the System Operator (National Grid) on the amount needed to meet the enduring reliability standard of 3 hours LOLE.
2. **Eligibility and auction:** The Capacity Market will be technology neutral and all existing and new forms of capacity (including demand side) will be eligible to participate, except for interconnected capacity, capacity receiving certain long-term contracts for the Short Term Operating Reserve and capacity receiving support through low-carbon support schemes such as the Renewables Obligation and FiT CfD. Providers will offer capacity in a pre-qualification process run by the System Operator. Pre-qualified capacity will then enter competitive central pay-as-clear auctions, also run by the System Operator. Successful bidders will be awarded 'capacity agreements'. Existing plant will have access to one year contracts, refurbishing plant to three year contracts, and new plant to fifteen year contracts.
3. **Secondary market:** Participants in the Capacity Market will be able to hedge their position through secondary trading. A participant can trade their obligation in advance of a stress event or reallocate volume following a stress event. Alternatively, a participant can undertake financial trading.
4. **Delivery:** Capacity providers will receive payment for capacity in the delivery year. In return they will be obliged to deliver energy in periods of system stress and will be financially penalised (following the publication of a Capacity Market warning) if they do not deliver in stress periods.
5. **Payment:** The costs of capacity agreements will be met by suppliers based on their market share at times of peak demand.

Option assessment

5.6 A Capacity Market is appraised through both qualitative and quantitative analysis. The quantitative analysis (in Section 6) shows that a Capacity Market has a net benefit where there is missing money.

5.7 However, the quantitative estimate does not take into account a number of significant factors. The qualitative assessment provides a more comprehensive assessment of the options.

6 Quantitative options assessment

6.1 The value for money assessment of the Capacity Market were assessed quantitatively in the following ways:

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

6.2 In addition to the value for money assessment, we have quantified the potential impacts of a Capacity Market on security of electricity supply and on electricity bills.

Administrative costs to Business

6.3 A Capacity Market is likely to create an administrative burden for businesses as they start participating in a new market. This has been estimated based on the assumption that companies participating in capacity auctions will require one or two members of full time staff, costing around £50,000 each and that the number of businesses affected is estimated to be between 51 and 120.[35] In the base case we have assumed the mid-way point in the estimated cost range (i.e. £6m per year) to be the best estimate of the administrative burden of a Capacity Market. This cost is incurred every year from 2013, i.e. a year before the assumed first auction in 2014, but in the first five years (i.e. 2013-17) it is assumed that costs are double as the mechanism is implemented. Given a 2014 first auction date, the present value of this cost over the period 2012-2030 is now estimated to be £112m.

Institutional costs

6.4 The institutional costs associated with delivering a Capacity Market have an estimated PV of £41m. Cost estimates include a portion of National Grid's administration costs as the EMR delivery body (those assumed to relate to Capacity Market administration), as well as provisional estimates for the Electricity Settlements Company costs for 2012 – 2016.[36]

[35] The number of businesses is based on the number of major power producers as listed in Table 5.11 of DUKES (2013), plus an estimated number of non-major power producers with more than 5MW of capacity (a subset of 'Other power stations' in Table 5.11).
https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/254261/ukesi_2013.pdf
[36] Further details are available at:
https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/298354/CFD_Counterparty_and_Electricity_Settlements_Company_operational_costs.pdf
Cost estimates should be regarded as tentative, as the component costs have not yet been fully determined.

Auction Modelling

The auction format for the Capacity Market is pay-as-clear, where each party taking on an agreement is paid the clearing price in the auction – set at the price of the most expensive unit accepted. This auction format should lead to the lowest costs for consumers. The rationale and analysis of this choice of auction format is set out in Annex A.

We have assumed in the modelling that under a pay-as-clear auction parties bid in their true cost. However, we recognise that there are gaming risks whereby parties may attempt to exercise market power to raise the clearing price. Despite this, we think the risk of overpaying in the auction has been largely mitigated through the detailed design choices:

- The auction is held four years out to allow sufficient time for new entrants to build capacity if successful in the auction
- A sloping demand curve will be set for the auction so that less capacity is bought if the price is very high
- A price cap in the auction will provide protection against the risk of an uncompetitive auction delivering a high price
- The capacity value of plants in the auction will be administratively determined, and where a plant chooses to "opt out" of the auction the demand in the auction will be lowered. This prevents existing plants from withholding capacity to drive up the price
- Existing plant will be assumed to be a "price-taker" by default. This means they will only be able to bid in up to a low level (50% of Net CONE). Alternatively, they can act as a price maker if they provide a Board-approved justification for why they need a higher price, and this can be used as evidence by Ofgem as part of any subsequent investigation into a potential breach of licence.

Energy system modelling

6.5 Energy system modelling of the electricity market provides a view of the costs and benefits of a Capacity Market, although there are significant caveats associated with the results. The methodology for the modelling is set out further in Annex G.

What capacity margin have we targeted in the modelling?

Government has proposed a reliability standard for the Capacity Market of 3 hours loss of load expectation (LOLE) per year. This means that we would expect on average three hours per year in which supply is insufficient to meet electricity demand, forcing the System Operator to enact involuntary load shedding – leading to voltage reductions (“brownouts”) and possibly customer disconnections (“blackouts”).

A LOLE of 3 hours per year is equivalent to a derated capacity margin of around 4%.

However, there is significant uncertainty over peak demand, and hence the capacity required, over the interval between the Capacity Market auction and the delivery year. The relationship between capacity margins and LOLE is asymmetric – LOLE increases faster as the capacity margin falls towards zero. As a result, the costs of higher lost load due to underestimating peak demand are greater than the costs of higher capacity payments due to overestimating peak demand. Analysis suggests that in order to take account of this uncertainty, and the asymmetry between capacity margins and LOLE, the level of capacity targeted in the modelling should be 3GW higher than estimated peak demand. Therefore, when procuring a LOLE of 3 hours per year, the outturn capacity margin in the delivery year is around 8%.

This target then informs the demand curve – with the capacity auction buying above or below the target depending on how far the capacity price is from Net CONE (£49/kW).

Modelling in the DDM assumes investors have perfect certainty about demand up to five years out – so concludes that that 8% capacity margin targeted is an overestimate of the capacity needed. This means that the DDM may overestimate the costs of the Capacity Market as it assumes an inefficiently high capacity margin is sought.

6.6 The costs modelled include the capital costs of the additional capacity incentivised by the Capacity Market, as well as the fuel and carbon costs associated with the additional capacity. The security of electricity supply benefit modelled is a reduction in unserved energy. This is mostly from reductions in involuntary energy unserved – i.e. lower blackouts and forced voltage reductions.

6.7 Benefits modelled come from reduced levels of forced outages. These are modelled below assuming a VoLL of £17,000/MWh. This implies that the average domestic household would pay around £6 to avoid being disconnected for an hour.[37] Uncertainty around the VoLL is considered further in the sensitivity analysis outlined below.

6.8 Tables 3 and 4 below show the results of energy system modelling in terms of the impact of the Capacity Market relative to the no Capacity Market scenario and how this breaks down into its various components. This also captures the wider monetised costs – the administrative burden on companies created by new regulation and the institutional costs to delivery bodies of running the mechanism.

[37] “The Value of Lost Load (VoLL) for Electricity in Great Britain”, July 2013, London Economics https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/224028/value_lost_load_electricty_gb.pdf

Present Value assessment

6.9 Modelling suggests that the Capacity Market has a marginal net benefit in the basecase. This is because an energy-only market with missing money leads to an inadequate level of investment in new capacity, resulting in a significant level of lost load. The benefit of greater reliability presented by the Capacity Market outweighs the cost of the additional capacity as well as the administrative costs on participants and the institutional costs of delivering the Capacity Market.

Table 3: **Estimated costs and benefits of a Capacity Market**

2012-2030	**£m (2012 prices)**		
	October 2013	**June 2014**	**August 2014**
Carbon cost[38]	854	46	85
Generation cost[39]	176	104	108
Capital cost[40]	-1415	-116	-218
System cost[41]	1184	529	535
Interconnection cost [42]	44	-248	-246
Energy System Costs	**843**	**315**	**264**
Institutional costs	**32**	**41**	**41**
Administrative costs	**231**	**112**	**112**
Energy System Benefits (Reduction in unserved energy[43])	**1,290**	**848**	**762**

Source: DECC modelling

Table 4: **Change in Net Welfare due to a Capacity Market**

Total costs	**1,107**	**468**	**416**
Total benefits	**1,290**	**848**	**762**
Change in Consumer Surplus	-10,417	-117	-757
Change in Producer Surplus	10,083	542	1,130
Change in Environmental tax revenue	517	-44	-27
Change in Net Welfare	**183**	**381**	**346**

Source: DECC modelling

[38] 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.

[39] These are the sum of variable and fixed operating costs. The carbon component of the variable operating costs is removed – the EUA price is accounted for in the carbon costs, and the carbon price floor cost is a transfer between producers and the Exchequer so appears in the surplus calculations but not in the net welfare. An increase in generation costs leads to a decrease in net welfare.

[40] All new build is included (plants built by the model, and pipeline plants). Construction costs are annuitized over the economic lifetime of the plant, based on the hurdle rate. An increase in capital costs leads to a decrease in net welfare.

[41] These are the sum of the costs from building and operating the electricity system (TNUoS and BSUoS costs). The increase in cost is mainly network costs from additional generation. These costs are calculated by National Grid models, based on DDM outputs. An increase in system costs leads to a reduction in net welfare.

[42] This measures the cost from electricity imported via the interconnectors net of the value of exports. If imports are greater or wholesale prices are higher than the cost of imported electricity is increased, scored as a reduction in net welfare.

[43] The estimation of Expected Unserved Energy takes plant outage probabilities, technology mix, demand and historical wind data and uses stochastic modelling to estimate a probability distribution of energy unserved. The mean unserved energy is valued at VOLL (defined by the user, assumed to be £17,000/MWh). An increase in unserved energy leads to a decrease in net welfare.

6.10 The estimated change in net welfare (£346m) is similar to estimates from both the October 2013 (£183m) and June 2014 Capacity Market Impact Assessments (£381m[44]). Since the June analysis, there have been only minor changes in the various cost and benefit components that comprise the overall net welfare estimate; the more significant changes have been between the October 2013 and June 2014 modelling (as set out in the June 2014 IA).

6.11 The result that a Capacity Market has a net benefit in the modelling is driven by the assumption of missing money – i.e. that the energy-only market would fail to bring forward sufficient investment in capacity as prices would not be able to rise to the VoLL and investors would fail to invest on the basis of uncertain and infrequent scarcity rents.

6.12 The modelling result for what technology is brought forward by the Capacity Market is sensitive to a range of assumptions, such as the degree to which generators can charge a markup in the energy market as well as the capital costs for new build capacity.[45] However, while there is uncertainty around the mix of plant that will come forward through the Capacity Market, the mechanism design should ensure that the market has optimal incentives to bring forward an efficient plant mix.

6.13 VoLL is particularly hard to estimate as it includes both the private costs to individuals from blackouts (which differ significantly between consumers and at different times of the year) and the wider social costs of blackouts, such as harm to Britain's reputation as a positive environment for investment. Studies indicating a plausible range of between £10,000 and £30,000/MWh.[46] The assumption of VoLL can have a significant impact on the size of total benefits and can affect whether a Capacity Market has a net cost or benefit. The size of benefits under different assumptions about VoLL is illustrated below.

Table 5: **Sensitivity analysis around energy system benefits from a Capacity Market**

NPV 2012-2030, £m (2012 prices)	**£10,000 VoLL**	**£17,000 VoLL**	**£30,000 VoLL**
Benefits from reduction in unserved energy	448	762	1,345

Source: DECC modelling

6.14 Modelling is likely to understate the benefits of a Capacity Market as it assumes an unrealistically perfect market where investors have perfect certainty of demand when choosing whether to build a new plant. However, the range in benefits if you change the assumption of VoLL illustrates that the impact of a Capacity Market is more beneficial, the greater the degree of "missing money" in the market and if that problem leads to the market failing to bring forward sufficient capacity.

6.15 We have also considered the impact of the Capacity Market against a counterfactual where the power sector decarbonises on an alternative trajectory, shown in the table below.

[44] This was incorrectly stated as £389m in the June version of the IA
[45] The price markup is the extent to which wholesale prices move above the short run marginal cost of the marginal plant. The price markup is expected to increase with lower capacity margins.
[46] Oxera report "What is the optimal level of electricity supply security", (2005)

Table 6: **NPV of Administrative Capacity Market under different decarbonisation scenarios**

NPV 2012-2030, £bn (2012 prices)	Decarbonisation target in 2030 (gCO_2/kWh)		
	50	**100**	**200**
Capacity Market	0.2	0.3	0.3

Source: DECC modelling

6.16 The NPV for the Capacity Market across all three decarbonisation scenarios up to 2030 is very similar, which shows that the modelling is robust to different states of the world. This is consistent with the expectation that, without the Capacity Market, industry will invest on the basis of being able to earn scarcity rents in the energy market. The Capacity Market will replace some energy market revenue with capacity payments. However, the modelling does not take account of the possibility that industry may not feel able to invest on the basis of infrequent and uncertain scarcity rents. Similarly, the modelling does not take account of the possibility that industry may not feel able to invest due to a concern that the Government/regulator will act on a perceived abuse of market power, at times when wholesale energy market prices peak to high levels. For these reasons, the modelling may underestimate the benefit of the Capacity Market.

Distributional impacts

6.17 The latest modelling shows **a net increase in the average annual domestic electricity bill of £2 over the period 2016 to 2030** (in 2012 prices). This is equivalent to a 0.3% average increase in domestic electricity bills. Gross capacity payments are estimated to increase the average annual domestic electricity bill by £14 over the period 2016 to 2030 (in 2012 prices). However, the Capacity Market is also estimated to lead to a reduction in wholesale prices, due to a greater amount of generating capacity being available and dampening the response of wholesale prices to potential tightening in security of electricity supply conditions. The table below shows the impact of a Capacity Market on the bills of different groups – domestic consumers, non-domestic consumers and energy-intensive industries (EIIs).

Table 7: **Electricity Bill Impacts**

Average annual bills, in 2012 prices	Typical bill without Capacity Market	Change with Capacity Market (%)
Domestic, (£)		
2011-2015	567	0%
2016-2020	590	1%
2021-2025	619	1%
2026-2030	716	-1%
Non Domestic (£000)		
2011-2015	1,100	0%
2016-2020	1,300	1%
2021-2025	1,400	2%
2026-2030	1,600	1%
Energy Intensive Industry, (£000)		
2011-2015	7,900	0%
2016-2020	10,100	2%
2021-2025	11,800	3%
2026-2030	12,800	1%

Source: DECC modelling

6.18 There are a range of other factors that could significantly affect the economic impact of a Capacity Market which are not reflected in the modelling. These include:

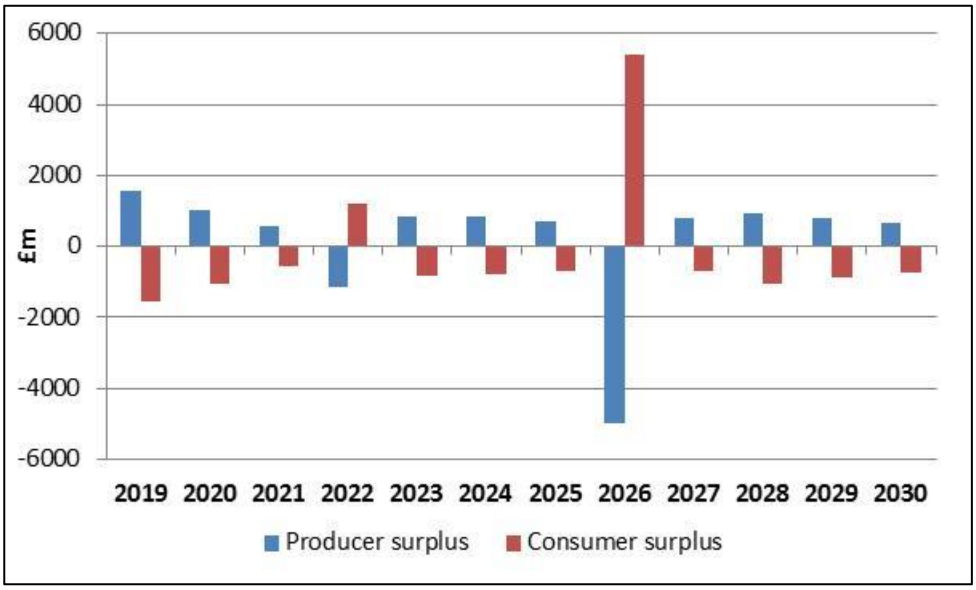
- The degree to which providing a stable capacity payment reduces risks for investment in new capacity and therefore brings the financing costs down.
- The degree of liquidity/competition in the capacity auction.
- Whether a central determination of the "optimal" level of capacity needed four years ahead is more or less successful than the market estimating how much additional capacity is needed.

6.19 Given these uncertainties, figures should therefore be treated with caution. However, the Capacity Market has been designed to reduce the impact on bills by ensuring a competitive outcome in the auction and ensuring that only the economically efficient level of capacity should be procured.

6.20 As well as the impact on consumers of electricity there is also an impact on the generation companies which produce electricity. The figure below shows the producer surplus resulting from the introduction of a Capacity Market. The Capacity Market increases producer surplus because it compensates generators for the "missing money" in the existing energy-only market and therefore provides some infra-marginal rents for existing capacity.[47] The reduction in producer surplus in 2026 is caused by an increase in the wholesale price in the no Capacity Market scenario. See the impact on wholesale market section below.

[47] i.e. capacity that would have been present without a capacity payment

Figure 3: **Change in producer and consumer surplus as a result of a Capacity Market**



Source: DECC modelling

Size of capacity revenues

6.21 The table below shows the estimated Capacity Market clearing prices for each delivery year up to 2030. Note that the estimated clearing prices can be very sensitive to changes in assumptions.

Table 8: **Prices in the Capacity Market, £/kW**[48]

(2012 prices)	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**
Capacity Prices (£/kW)	42	30	18	35	29	37	36	33	35	36	34	32

Source: DECC modelling

6.22 Capacity prices differ from the central estimate of Net CONE for a number of reasons:

- Sunk costs: In some years additional capacity is not needed and the price is set by existing plant, which tends to set a lower price than new plant.

- Ancillary service payments: Plant are assumed to receive some rewards for ancillary services offered. It is recognised that there is significant uncertainty around these estimates – for instance whether they impose an opportunity cost on generators (i.e. they forego the opportunity to make energy market rents) or whether they are for services not valued through the energy market (such as for mitigating locational constraints or providing very flexible generation).

[48] "2019" refers to the period from October 2018 to September 2019, "2020" refers to the period from October 2019 to September 2020, etc.

- Build constraints: It is assumed that it is only possible to build up to 4GW of OCGTs in a given year. This constraint applies to both large-scale and small-scale OCGT. Furthermore, the model constrains build of both OCGT and Combined Cycle Gas Turbines (CCGTs) at 6 GW in a given year. Both CCGT and OCGT are assumed to get more expensive as more plants are built in any given year. These build constraints and cost ranges are based on the update from Parsons Brinckerhoff and take into account technical feasibility of new build gas plant in the UK.[49]

6.23 The gross capacity revenues going to providers of capacity based on the latest modelling are between £0.7bn and £1.8bn per annum (in real 2012 prices). It should be noted however that projections of the capacity revenues are highly uncertain and are sensitive to a number of assumptions around how competitive the auction is, the cost of new entry, and whether investors value scarcity rents when choosing how to price into the capacity auction. In theory, as cash-out is fully reformed and the market has confidence to invest on the basis of scarcity rents the capacity price should tend towards zero under a Capacity Market.

6.24 We have also considered the Capacity Market clearing prices in a scenario where there is a change to the relative price between gas and coal. The table below shows the estimated Capacity Market clearing prices in a scenario which uses DECC's central gas price assumption and low coal price assumption.

Table 9: **Estimated clearing prices in a scenario with central gas price assumptions and low coal price assumption, £/kW[50]**

(2012 prices)	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**
Capacity Prices (£/kW)	42	33	19	31	25	36	34	33	34	37	36	49

Source: DECC modelling

6.25 The estimated clearing prices in this scenario are similar to those in the central scenario. This suggests that the change in relative price between gas and coal has had little impact on the energy market rents of the marginal plant in the Capacity Market. Note that this result may be different under alternative fossil fuel price trajectories.

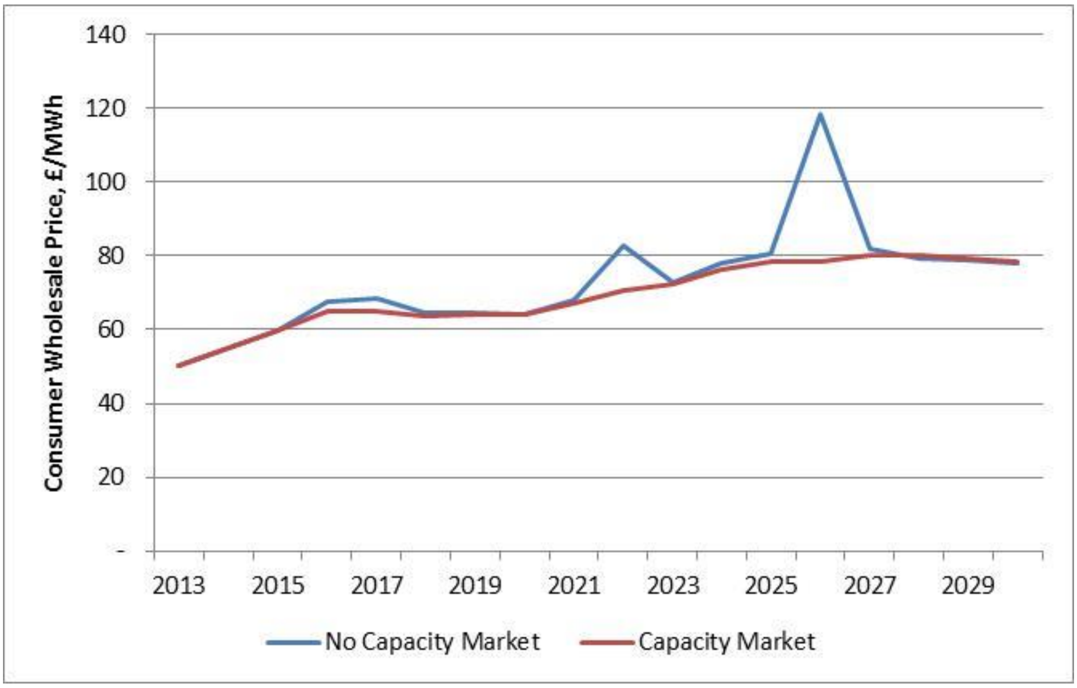
Impact on wholesale market

6.26 Modelling shows that the Capacity Market leads to a decrease in wholesale prices. This is largely because under the Capacity Market capacity margins tend to be higher. Lower capacity margins are likely to lead to higher scarcity rents being made in the energy market. Therefore, the Capacity Market leads to a reduction in scarcity rents and lower wholesale prices.

[49] https://www.gov.uk/government/publications/coal-and-gas-assumptions
[50] "2019" refers to the period from October 2018 to September 2019, "2020" refers to the period from October 2019 to September 2020, etc.

6.27 The Capacity Market targets a LOLE of 3 hours per year. As a result, capacity margins are similar in every year under the Capacity Market. This means the Capacity Market also leads to less volatile wholesale prices. The modelling shows a large increase in the wholesale price in the no Capacity Market scenario in 2026. This is caused by very low capacity margins in the no Capacity Market scenario in 2026. Note that while the modelling suggests capacity margins will be lowest in 2026 in the no Capacity Market scenario, the modelling is very sensitive to when plant retire. A slight change to the assumptions could lead to very low capacity margins in other years, in the no Capacity Market scenario.

Figure 4: **Wholesale electricity prices, £/MWh**



Source: DECC modelling

6.28 However, there is still some uncertainty around the impact of the Capacity Market on wholesale prices. This IA estimates that the Capacity Market brings on more CCGT than is estimated in the October 2013 IA. As a result, there is more of a downward effect on wholesale prices due to this new CCGT plant pushing other less efficient plant, such as old CCGT or coal plant, down the merit order.

6.29 There is also uncertainty around the degree to which an energy-only market would bring on sufficient new capacity or how generators might affect their pricing strategy in the wholesale market if margins tightened significantly. Experience from the Californian energy crisis in 2001 provides some instructive lessons about wholesale prices in a market with tight capacity margins. While the underlying causes of this event may not be the case in the UK[51], this event showed that where an energy-only market leads to underinvestment in new capacity then wholesale electricity prices can increase markedly as generators become more able to exercise market power in the wholesale market.[52] So the introduction of a GB Capacity Market provides a hedge against the risk of high wholesale prices caused by tight capacity margins.

[51] An investment hiatus caused by perceived regulatory risk and a retail price freeze leading to poor liquidity in the wholesale market
[52] De Vries, 2004, "Securing the public interest in electricity generation markets", http://www.nextgenerationinfrastructures.eu/download.php?field=document&itemID=449557

Conclusions from quantitative modelling

6.30 Quantitative modelling provides useful insights into the overall impact of the Capacity Market, namely the value of the greater reliability it provides and the cost of the additional capacity.

6.31 However, the results are sensitive to a number of assumptions made – such as the VoLL, or to investors' ability to invest on the basis of infrequent and uncertain scarcity rents.

6.32 There are also limitations to the DDM's ability to perfectly reflect how investment decisions would occur in reality. The model is unable to capture the impact of differences in the detailed design of the mechanism – for instance around measures to mitigate gaming in the auction, or the effect of the penalty regime on dispatch decisions. These factors are considered further in the Qualitative Assessment, and the explanations for particular design choices are set out in the annexes to this IA.

7 Qualitative options assessment

7.1 There are a number of limitations to using energy system modelling to assess the impact of a Capacity Market. This section considers the additional non-quantifiable risks associated with introducing a Capacity Market relative to the basecase – particularly the potential for gaming, and implication for the Single Market.

7.2 Further qualitative analysis is set out in the annexes assessing the detailed design choices that have informed the final design of the Capacity Market. These design choices include:

- The choice of auction format;
- The timeline for procuring capacity;
- The choice of agreement length;
- The demand curve;
- Eligibility rules for participation in the Capacity Market;
- The level of penalties and when they are applied; and
- Energy system modelling

7.3 DECC regularly seeks to improve its modelling capabilities and has undertaken a number of changes to the model to reflect the final policy design. However, the degree of nuance involved in the policy design choices listed above mean that it in practice these are mainly assessed qualitatively.

Gaming risk

7.4 One of the principal risks identified in previous Capacity Market IAs is that of gaming. Capacity Markets are significant interventions in the market, adding complexity to the market and so creating potential for unintended consequences and for market participants to exploit arrangements to be able to earn undue profits.

Auction Design

7.5 Existing plant in the auction are likely to have significantly lower capacity bids than new build as existing plant will not need to recover its fixed costs. Moreover, demand in the capacity auction is price inelastic as parties have a high aversion to load shedding if insufficient capacity is procured. These two factors combine to mean that capacity prices could vary significantly whether new build sets the price in a given year. This creates incentives for auction participants with a sizeable portfolio of generators to withhold some of their capacity from the auction – either by keeping some plant outside of the auction or by offering it into the auction at a high price – in order to drive the price up to the cost of new entry. However, given the scale of new investment needed – incumbent players should have limited incentive to withhold capacity.

Penalty regime

7.6 Parties seeking to manipulate the rules to receive undue profits may attempt to overstate the value of their capacity. This can occur in a few different ways:

- By overstating the reliability of a plant prior to the auction. Significant uncertainty and asymmetric information exists about the capacity value of providers between the System Operator and the providers themselves. Providers have incentive to overstate the reliability of their capacity at the auction to receive higher payments, and the risk of penalties for underdelivery may be an insufficient deterrent to this action as stress events will be infrequent and as liabilities in the mechanism are capped.

- By appearing to overdeliver capacity in stress events. Providers with obligations might have incentive to artificially create or prolong a stress event in order to receive overdelivery payments, or (in the case of Demand Side Response) they might have incentive to manipulate the baseline against which they are assessed so they appear to have delivered more energy than is the case.

Mitigation of risks in design

7.7 The Capacity Market has sought to mitigate such potential for gaming in its design and has built in a number of policy design features specifically to mitigate the risks identified above. These mitigation measures include:

- Holding auctions four years out to allow for new entrants to compete against existing plant.

- Administratively determining the capacity value of participants – to prevent providers from understating the capacity value of their plants to withhold capacity from the auction, or overstating the value to receive undue capacity payments. This is complemented by a system of physical checking and spot tests to ensure capacity is able to deliver.

- Reducing demand in the auction where existing plant chooses to “opt out” of participation. This means that plant will not be able to game the auction by withholding plant.

- Existing plant will be required to act as price takers in the auction unless they are able to justify a need to set the price above a low threshold.

- The level of supply in each auction round and the identity of particular bidders will be concealed to mitigate risk of collusion.

- The demand curve will ensure the capacity price is less sensitive to the volume of capacity offered into the auction and so reduce incentives for participants to withhold capacity from the auction.

- There are provisions to cancel or postpone the auction if it is undersubscribed.

- There is a strong penalty regime for providers that fail to deliver energy when needed.

- There will be a system of periodic reviews to consider whether the rules are fit for purpose once the mechanism is in place.

Gaming risks without a Capacity Market

7.8 While the risk of gaming and unintended consequences must be considered as part of the assessment of the introduction of a Capacity Market, it is also important to recognise that there are gaming risks to having an energy-only market which are potentially more significant.

7.9 An energy-only market is likely to lead to under-investment in capacity due to the market failures identified in Section 4. However, as margins tighten in the electricity wholesale market, particularly at times of stress, generators become able to withhold supply from the market in order to drive up price. If this happens it may be hard to distinguish between anti-competitive gaming and legitimate pricing behaviour whereby generators recover their fixed costs. Experience from the Californian energy crisis in 2000 and 2001 demonstrates that a lack of investment in generation capacity can undermine the competitiveness of the market, as generating companies withheld supply in order to drive prices above their competitive levels when margins became slim.[53] Given the time it takes to build new plant, once the market reaches a point at which margins are slim, generators can continue to exercise market power for a protracted period of time in absence of regulatory intervention.

7.10 A Capacity Market reduces gaming risk in the energy market in a number of ways.

- The Capacity Market ensures a sufficient capacity margin to limit market power for generators in the wholesale market.
- A Capacity Market means energy prices need not be allowed to rise all the way to the VoLL (£17,000/MWh) at times of stress and can be capped at a lower level without compromising generation adequacy – which further mitigates incentives to withhold energy at times of stress.
- Finally, a Capacity Market ensures capacity remuneration is set in a more competitive, transparent and well-regulated process. Because this market is held four years out and not under stress conditions it can build in the mitigations enumerated in this section to limit gaming risk: For instance unlike in the energy market, the Capacity Market features a demand curve, a price cap, obligations on existing plant to act as price-takers, the threat of new entry, and an arrangement that sees demand lowered where existing plant "opt out" of offering capacity into the auction.

7.11 Thus the overall impact of a Capacity Market should be to reduce gaming risk relative to an energy-only market.

Conclusions from qualitative analysis

7.12 A Capacity Market acts to mitigate potentially significant risks to security of electricity supply associated with the market failing to invest sufficiently in reliable capacity. However, it is a significant and complex intervention which inevitably has some risk of unintended consequences – particularly around competition in the auction and correctly estimating the value of capacity offered by particular providers. However, while some risk is unavoidable, the mechanism design builds in a number of measures to mitigate these risks wherever possible and builds on from experiences of other capacity markets in the world, particularly in the US (e.g. PJM and ISO-New England).

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[53] De Vries, 2004, "Securing the public interest in electricity generation markets", http://www.nextgenerationinfrastructures.eu/download.php?field=document&itemID=449557

7.13 The risk of gaming in the Capacity Market must also be considered against the gaming risks associated with not intervening in the market. An energy-only market is likely to deliver a tighter capacity margin in the future, and this creates greater opportunities for parties to withhold energy from the market to drive the price up to VoLL. This risk may be greater than the threat of parties withholding in the capacity auction as there wouldn't be the same safeguards in place to protect consumers – i.e. the use of a demand curve, restrictions on bidding behaviour by existing plant, and minimum competition requirements in the capacity auction do not hold in the energy market at times of stress.

8 Conclusion

8.1 The energy system modelling for this Impact Assessment reinforces the analysis provided by Ofgem's 2013 Electricity Capacity Assessment and by previous Impact Assessments: that capacity margins are going to tighten over this decade; that the scale of the investment challenge over the medium term is considerable, and that there is uncertainty over the ability of the energy-only market to provide sufficient incentives for investment.

8.2 The case for a Capacity Market is therefore ultimately a judgement on the balance of risks around intervening in the market or trusting cash-out reforms and the market to deliver. A Capacity Market serves to mitigate the risk that an energy-only market does not provide sufficient capacity, due to investors being unable to get project finance for new capacity on the basis of uncertain and infrequent scarcity rents. The modelling in this IA shows that a Capacity Market has a positive impact on society as a result of mitigating market failures and ensuring an efficient level of investment in capacity. Given the limited impact of the measure to consumer bills and the potentially large cost from blackouts if the market fails to deliver sufficient capacity there is a strong case for introducing a Capacity Market.

8.3 There is no design of Capacity Market that is without risk, and the annexes set out the range of detailed design choices that have been made and the trade-offs associated with each choice. In particular the mechanism has been designed with a strong focus on designing a competitive auction process to enable efficient price discovery. It has also been recognised that it is important that the Capacity Market acts as a complement to reforms to the energy market (such as cash-out reform, measures to promote liquidity, and the introduction of Smart Meters), and that the necessity and design of the mechanism are kept under regular review as the mechanism is implemented and as the energy market evolves.

9 Other Impacts

Impact on small firms

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

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

UK Competitiveness

9.3 A Capacity Market has the potential to increase energy bills, which could negatively affect UK competitiveness. However, this cost needs to be considered against the significant harm to UK competitiveness that could arise if the energy-only market failed to deliver security of electricity supply objectives, leading to blackouts and which could have a damaging impact on the UK's reputation.

Implications for One-In, Two-Out

9.4 Based on the latest HMT advice, the Capacity Market options are to be treated as tax and spend measures, so would be out of scope for One-In, Two-Out (OITO).[54]

Equality impact

9.5 It is not envisaged that the Capacity Market will impact on measures of equality as set out in the Statutory Equality Duties Guidance. Specifically, options would not have different impacts on people of different racial groups, disabled people, men and women, including transsexual men and women. There are also no foreseen adverse impacts of the options on human rights and on the justice system. We will keep a watching brief on this but we are confident that any issues have been addressed at the design stage without adverse impact on either human rights, or on the effectiveness of the mechanism.

Impact on Business

9.6 Businesses would be affected in a number of ways by a Capacity Market. The key quantified impacts are:

- The benefit to businesses of reduced energy unserved[55]

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

[55] Calculated on the basis that 58% of electricity consumed is by non-domestic consumers and therefore around 58% of the benefit of reduced energy unserved will be experienced by businesses (DUKES 2013, Chapter 5). We have assumed that businesses have the same VoLL on average as consumers (£17,000/MWh). Whilst SMEs will generally have a higher VoLL, large industrial users will typically have a lower VoLL.

- The change in producer surplus that capacity providers face as a result of the Capacity Market (by receiving capacity payments but also receiving less revenues in the electricity market due to a dampened wholesale price)
- The administrative costs on electricity companies associated with participating in a Capacity Market
- The impact on business from facing higher energy bills as a result of the Capacity Market.[56]

9.7 A Capacity Market is modelled as having a positive impact on businesses, as the benefits of reduced energy unserved and rents accrued by providers in capacity auctions outweigh the increased costs to businesses from higher energy bills. However, this benefit is principally received by generators, largely at the expense of business in general, as reductions in energy unserved is smaller than the increase in bill costs.

Table 10: **Impacts of a Capacity Market on Business**

Impact on business, 2012-2030	**£m**
Administrative costs	112
Cost to business of increased energy bills	439
Total costs	**551**
Reduction in energy unserved	442
Producer surplus to capacity providers	1,130
Total benefits	**1,572**
Net impact on business	**1,021**

Source: DECC modelling

[56] Calculated on the basis that 58% of electricity consumed is by non-domestic consumers and therefore businesses would face an equivalent proportion of the impact on consumer surplus identified in the energy system modelling.

10 Post-Implementation Review

10.1 The Department of Energy and Climate Change has committed to regular reviews of the Capacity Market. This will be a five-yearly review of the mechanism. The objectives of the review will be as set out in the Energy Act 2013 – i.e. the report will:

- set out the objectives of the provisions of each Chapter subject to review
- assess the extent to which those objectives have been achieved, and
- assess whether those objectives remain appropriate and, if so, the extent to which those objectives could be achieved in a less burdensome way.

10.2 This review will involve a public consultation to invite views. The outcome of the review will be published.

10.3 DECC is also planning an independent evaluation of the Capacity Market (and Contracts for Difference). This will be commissioned from external evaluators in order to provide independent assurance and utilise networks and evidence outside the Department. The evaluation will provide assurance that is complementary to planned internal reviews.

10.4 Ofgem will also complete a yearly review of the operational effectiveness of the Capacity Market. This will be delivered within six months of the Capacity Market auction.

Annex A: Auction Format

1. The auction format chosen for the Capacity Market is a descending-clock, pay-as-clear auction in which all successful suppliers are paid the last-accepted bid. This annex sets out the analysis that underpins these design choices and the alternative options considered:

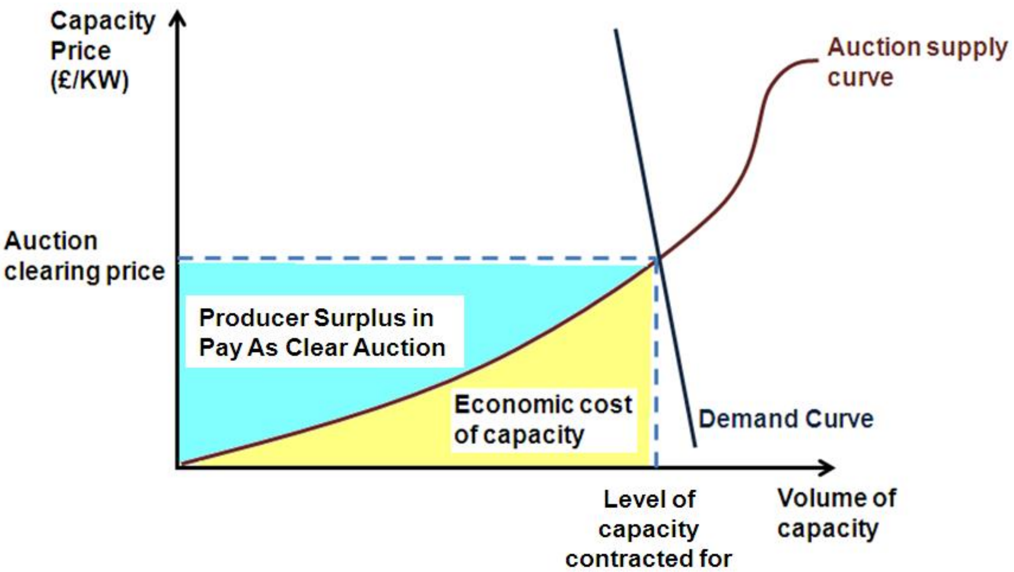
   - Pay-as-clear versus Pay-as-bid
   - Descending clock versus Sealed-bid
   - Last-accepted bid versus first-rejected bid

Pay-as-Clear versus Pay-as-Bid

2. Wholesale electricity markets are commonly organised around a spot energy market. Forward contracts tend to constitute the majority of wholesale electricity trading, the prices of which are a reflection of the spot price. Suppliers submit bids and the market clears at the price that balances supply and demand. Under a pay-as-clear auction all parties are paid the market clearing price set by the marginal bid into the auction.

3. By contrast, a pay-as-bid auction pays each successful bidder the price it bids. Pay-as-bid auctions are thus commonly referred to as discriminatory auctions because they pay successful bidders different prices based on their specific price bid. Pay-as-bid auctions are sometimes promoted as a way to reduce the cost to suppliers, resulting in lower consumer prices for electricity, as described by Giulio and Rahman.[57] However, to the extent that parties are able to exercise market power, then this approach is likely to produce the opposite result – strategic bidding by suppliers, inefficiency in plant dispatch and capacity investment, and ultimately a higher average price as described by Tierney.[58]

Figure 5: **Pay-as-clear auction**



[57] Federico, Giulio, and David Rahman. "Bidding in an electricity pay-as-bid auction." *Journal of Regulatory Economics* 24.2 (2003): 175-211. Available at: http://www.nuff.ox.ac.uk/economics/papers/2001/w5/federico-rahmansept2001.pdf
[58] Tierney et al, "Pay-as-Bid Vs Uniform Pricing," Fortnightly Magazine, March 2008

4. The key motivation for a pay-as-clear auction is that it provides suppliers with stronger incentives to bid their true economic cost of providing capacity. In a setting where there is no uncertainty about the clearing price, a pay-as-bid auction creates incentives for bidders to attempt to shadow-price the marginal bid and ensure they are successful. Even though in a pay-as-clear auction some suppliers are being paid more than the economic cost of capacity, this effect is mitigated by greater incentives to bid at true economic cost.[59] In this way, the auction identifies the most economic suppliers of capacity and pays the lowest single-price that attracts enough supply to meet demand.

5. Under a pay-as-clear auction, each supplier receives a *uniform* market-clearing price, set at the offer price of the most expensive resource chosen to provide supply i.e. the marginal auction offering.

6. In a pay-as-bid auction, a plant will seek to cover its fixed and variable costs. If the cost of production (e.g. due to increase in fuel price) for one technology (e.g. CCGT or onshore wind) increases, and the price offered by this technology increases as a consequence, there will be no incentive for investment in the relatively cheaper technology (say nuclear plants or photovoltaics) as they will still only look to cover fixed and variable costs. Under pay-as-clear auctioning, where a uniform price is offered, more investment will occur where it is more economically efficient to do so (in this example, nuclear power plants or photovoltaics). This case, along with further nuances, is put forward by Cramton and Stoft.[60]

7. Alongside economic efficiency benefits, pay-as-clear auctions also have a number of advantages over pay-as-bid auctions in this context:

   - Competition: Pay-as-bid auctions introduce a "guessing game" for suppliers. Those suppliers best able to predict the clearing price will be able to bid the most aggressively and thereby reap the largest profits. Often, this gives an advantage to large portfolio players who have better information to forecast the clearing price, and indeed can take actions to impact the clearing price in significant ways. In contrast, small independents are at a disadvantage, since they are likely to have fewer resources to estimate the clearing price and less ability to impact the clearing price. The exercise of market power by a large participant in a pay-as-bid auction tends to reinforce market concentration. By contrast, in a pay-as-clear auction, the exercise of market power by large participants tends to be self-correcting. Smaller suppliers are able to free-ride on the exercise of market power by large suppliers. Thus, the exercise of market power with pay-as-bid pricing, because it favours larger bidders, will tend to encourage consolidation and discourage entry. In contrast, the exercise of market power with uniform pricing encourages entry and reduces concentration. As a result, the market may evolve to more competitive structures under uniform pricing.[61] This action makes room for smaller participants and thereby encourages entry in the long-term, which

[59] Academic studies reaching this conclusion include Alfred E. Kahn, Peter Cramton, Robert H. Porter, and Richard D. Tabors, "Uniform Pricing or Pay-as-Bid Pricing: A Dilemma for California and Beyond," *Electricity Journal*, 70-79, July 2001

[60] Cramton, Peter, and Steven Stoft. "Why we need to stick with uniform-price auctions in electricity markets." *The Electricity Journal* 20.1 (2007): 26-37.

[61] Cramton, Peter, and Steven Stoft. "Why we need to stick with uniform-price auctions in electricity markets." *The Electricity Journal* 20.1 (2007): 26-37.

helps to mitigate incentives for large participants to withhold. There remains a risk of collusion in a pay-as-clear auction, although this is likely to be a small risk given that there are significant legal penalties.

- Long-term price signals*:* Paying the clearing price can create the right long-term signals for the market to innovate and develop cheaper technologies so as to capture later rents in the capacity market. A market that pays a single price provides incentives for everyone to try to provide capacity at less than this price. Over time this puts downward pressure on the price and therefore tends to achieve the lowest long-term sustainable price.

- Fairness: In markets it is seen as a fair outcome for parties to be paid the same price for provision of a homogenous product. In the Capacity Market the homogenous product is the provision of available capacity at times of system stress, and is designed to be a technology neutral product. In this way new and existing plant, as well as DSR and storage, can compete openly against each other in the auction. The pay-as-clear auction pays each supplier the same price. In contrast, the pay-as-bid auction pays different parties different prices for providing the same service. This may be viewed as unfair. In a pay-as-bid auction, artificial transaction costs between seller offers appear in the spot market and buyer bids exist to discourage its use, which has been a feature of the UK market in recent years.[62] These sunk costs are avoided through uniform prices as prices paid are exactly equal to those received.

8. However, there are still risks associated with running a pay-as-clear auction for capacity. The main risk is the exercise of market power to achieve a high price. This incentive may be greatest in years in which no new build is required. Existing resources are likely to have much lower costs than new capacity, and therefore the competitive clearing price may be quite low in these years. To avoid this low price, large existing players may bid a much higher price.
9. This risk should be largely mitigated through the other measures in the mechanism design to ensure competition in the auction – such as use of price-taker requirements for existing plant and a downward sloping demand curve. These are detailed in Annex D.

Descending-Clock versus Sealed-Bid

10. The proposed format is a descending-clock auction with pay-as-clear pricing. This involves the auctioneer announcing a high price at the beginning of the auction and providers indicating that they are willing to supply capacity at that price, and then repeated rounds at lower prices until the auction discovers the lowest price at which demand equals supply.
11. This option is an alternative to a sealed bid auction, whereby providers each state the minimum price at which they are willing to provide capacity and the auctioneer

[62] Cramton, Peter, and Steven Stoft. "Why we need to stick with uniform-price auctions in electricity markets." *The Electricity Journal* 20.1 (2007): 26-37.

identifies the marginal bid (i.e. the most expensive bid accepted) and sets that as the clearing price.

12. The descending clock format has several potential advantages over a sealed-bid format.

13. One benefit is reduced uncertainty about common cost elements that may be revealed in the bidding process. This reduction of uncertainty enables bidders to bid more aggressively without fear of the winner's curse (i.e. in the case of this descending clock auction, winning at a price that is too low) because new entrants know they can withdraw their bid once they see a significant number of other bidders withdraw from the auction. This reduction of uncertainty can both increase revenues and improve efficiency.[63]

14. A second benefit is improved price competition. Bidders often bid more aggressively in dynamic auctions for various behavioural reasons. For example, dropping out of the auction is an admission of "inferiority"—that the supplier has higher costs than a competitor.[64]

15. A descending price auction, allows bidders to condition future bids based on the results of previous bids and the bidding behaviour of other bidders, allowing the bidder to revisit its reserve price and resulting in a more efficient process.[65]

16. It is recognised that there are disadvantages to descending clock auctions relative to sealed-bid: It could be more administratively onerous for parties to participate in a descending clock auction as it takes place over a longer time period. Moreover, the price-discovery afforded by descending clock auctions can also be used by parties to collude (explicitly or tacitly), driving up prices.

17. However, the risks of descending clock auctions can largely be mitigated through mechanism design. Auction participants can be allowed to put in proxy-bids so that they don't have to be present for the whole auction process. Further, the risk of collusion is largely mitigated by a licence obligation on auction participants not to collude or share information, allied to the ability of Ofgem to investigate and ultimately impose strong penalties on offending parties. Tacit collusion is also mitigated through the conduct of the auction, such as the size of the bid decrements and the information policy.

Last-accepted bid versus first-rejected bid

18. A further significant policy decision is whether to set the clearing price at the price of the first-rejected bid or the last-accepted bid. The first-rejected bid provides further incentives for parties that are aware that they are the marginal plant to bid in their true cost rather than to bid up to cost of the least-cost plant that will be rejected. However, in practice it is likely that setting the price at the last-accepted bid is likely to reduce costs for consumers. This is because there is likely to be some uncertainty around the price of the marginal plant and so it would be difficult for incumbents to

[63] Milgrom, Paul and Robert J. Weber (1982), "A Theory of Auctions and Competitive Bidding," *Econometrica*, 50, 1089-1122.
[64] Peter Cramton, "Ascending Auctions," *European Economic Review* 42:3-5 (1998) 745-756.
[65] Maurer, Luiz and Barrosa, Luiz, *Electricity Auctions: An Overview of Efficient Practices*, World Bank Publications, 2011.

game the auction by bidding up to the price of the lowest-cost plant to be rejected. This is the most common pricing rule in pay-as-clear auctions.

Conclusion

19. Based on the analysis outlined above we see a number of advantages to a pay-as-clear auction format to ensure the market delivers the efficient long-term price signals for competition and innovation. In the long run this should lead to lower costs for consumers, particularly as the pay-as-bid auction creates perverse incentives for providers to overstate their costs and skews the market in favour of large portfolio players. However, we recognise the risk of overpayment under a pay-as-clear auction if existing plant are able to drive the price up to the cost of new entry in years when no new build is needed – and so we have put in place a range of measures to mitigate this gaming risk.
20. Similarly, a descending clock auction is preferred as it enables greater price discovery and so should further reduce risk for the market to invest in capacity.
21. The choice of auction format (pay-as-clear with descending clock) is consistent with the principal capacity markets in the United States, including PJM and ISO-New England.

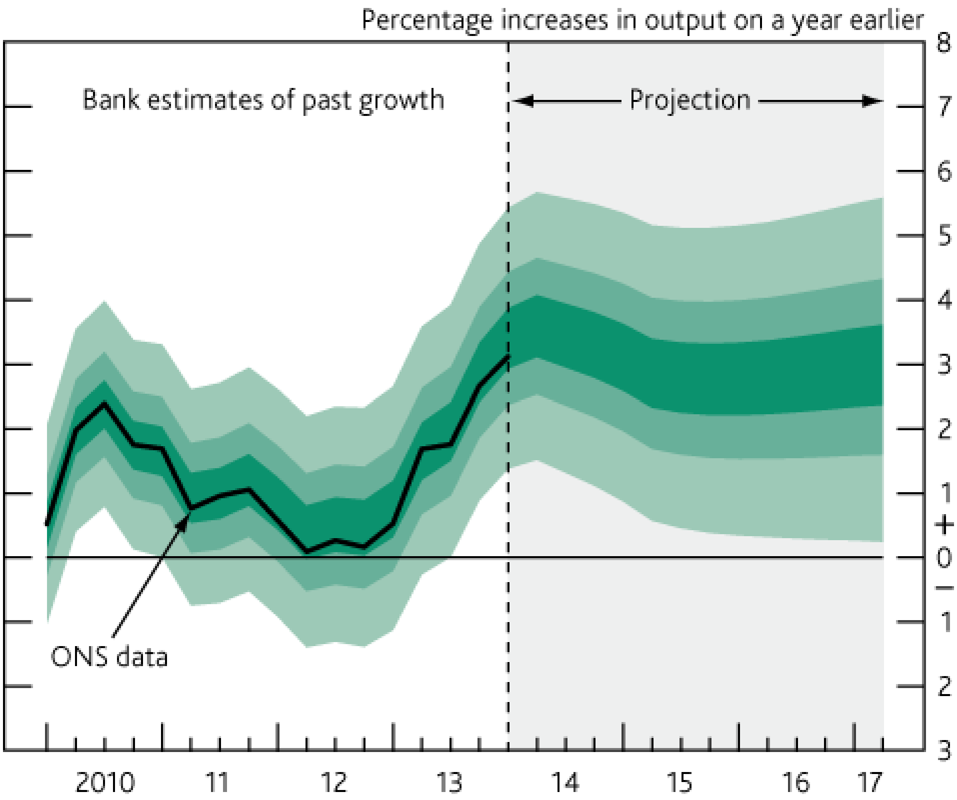
Annex B: Timeline for procuring capacity

1. The principal capacity auction is to be held four years ahead of the delivery year (T-4), with a supplementary auction held one year ahead of the delivery year (T-1). The amount of capacity to contract at the (T-1) auction will be determined on the basis of an assessment of how much DSR is expected to come forward. This annex considers the issues around the choice of a (T-4) auction and why this was chosen over a single (T-1) auction.

Efficient risk allocation

2. In running an auction four years out it is necessary to assess the need for capacity in the delivery year – and there is likely to be significant uncertainty around this assessment. Uncertainty around the volume to procure four years out comes from both demand (e.g. economic growth as shown in the chart below and the effectiveness of energy efficiency programmes) and supply (e.g. the expected commissioning date for a new nuclear plant or the degree of investment in new renewable capacity).
3. Procuring capacity through a single (T-1) auction would clearly carry less risk in terms of contracting the right volume of capacity, as there is much greater certainty as the delivery year approaches.

Figure 6: **Fan Chart with GDP Growth Projections**



Source: Bank of England[66]

[66] May 2014, Bank of England Inflation Report, http://www.bankofengland.co.uk/publications/pages/inflationreport/irfanch.aspx
Note that DECC uses projections from The Office for Budget Responsibility rather than The Bank of England

4. However, the suitability of contracting closer to the delivery year carries alternative risks. It is not possible to build new thermal capacity at the (T-1) stage (although it may be possible to incentivise new DSR or some existing plant that would otherwise retire to stay open). The length of time taken to build new plants is illustrated in the diagram below:

Table 11: **Lead times for new build (number of years)**

	Predevelopment Period (Years)	**Construction Period (Years)**
CCGT	2.3	2.5
OCGT (large scale)	1.8	1.8
OCGT (aeroderivative)	2.1	1.9
Nuclear	5	6
Gas - CCGT with post combustion CCS – FOAK	5.0	4.5
Coal - ASC with CCS – FOAK	6	5.5
Coal - IGCC with CCS – FOAK	5.3	5
Pumped Storage	5	4.5

Source: Parsons Brinckerhoff[67]

5. Relying on a (T-1) auction in years when new build may be needed would therefore impose a higher level of risk on investors than having a (T-4) auction. With a (T-1) auction, the market would have to estimate the need for new plant four years ahead and invest in new capacity needed, so that it will be able to participate in the (T-1) auction. This is similar to how investment is funded in an energy-only market, where there is limited liquidity in forward markets beyond a year ahead.
6. An advantage of procuring capacity close to the delivery year is that it would incentivise the market to bring forward types of capacity that can be built as quickly as possible – as they face the least risk of not being needed by the time of the auction.
7. However, a (T-1) auction is likely to be a less efficient allocation of risk than contracting new capacity four years out. The market is as likely to correctly estimate capacity needs four years out as the Government is. The main advantage to procurement four years ahead of the delivery year is that it mitigates the coordination problem with leaving the market to decide which power plants to build. For instance, it may be that there is market consensus that only one or two new gas plants will be needed in four years' time. If there is no central (T-4) auction then investors deciding whether to build must first make a judgement about whether other investors will do the same. This can lead to potential overinvestment or underinvestment where investors fail to guess correctly the actions of other market players. Investors may publicise that they have made final investment decisions to deter other investors from building new plant. However, investors may have perverse incentives to make such declarations even when they have not yet made a final investment decision. Therefore, (T-4) auctions provide a mechanism for coordinating which investors will build the additional capacity that is needed.

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[67] For all technologies apart from storage: https://www.gov.uk/government/publications/parsons-brinkerhoff-electricity-generation-model-2013-update-of-renewable-technologies
For Storage: https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/65712/6884-electricity-gen-cost-model-2012-update.pdf

8. There is also additional risk for the market around how the price will be set in the auction. In a (T-4) auction, new build offers will price their bids based on the cost of new entry – i.e. the level of payment at which it is profitable for the plant to be built. However, in a (T-1) auction the capex and pre-development costs of the new build will have already been sunk, so if there is any risk that the investor may not receive a contract in the auction then they might bid below their cost of new entry to ensure they get at least some revenue to cover fixed costs. This may lead to new build making a loss and so would incentivise new build to bid into the (T-4) auction.

Technology neutrality

9. An important principle in the design of the Capacity Market is technology-neutrality. The Capacity Market has been designed to create the same incentives that would be present in an efficient energy-only market, and one such incentive would be for the market to select the efficient mix of plant in response to price signals.

10. However, it is recognised that the choice of how far out to hold the auction has potential to affect the likely mix of plant that comes forward. In particular, (T-1) auctions favour existing plant and DSR, (T-4) auctions might favour gas plant but disadvantage DSR (which may struggle to commit four years ahead – for example, an aggregator may not know how many customers it will have) and storage or new nuclear (which may take longer than four years to build).

11. Modelling of the energy system suggests that significant new gas build is needed – although this projection could be less if interconnection or DSR delivers more than expected or if an innovative new technology came forward to replace OCGT as the marginal plant.

12. The choice to have two auctions – a primary auction at (T-4) and a supplementary (T-1) auction – enables both gas and DSR to participate effectively in the auction. The decision of how much capacity to procure at the (T-1) auction is clearly likely to be influential to the technology mix that the Capacity Market will bring forward. However, with each additional auction there should be greater certainty about the volume of DSR that can participate cost-effectively against thermal plant, and Government can learn if past estimates were too high or too low based on whether the (T-1) auction cleared at a price greater than or less than the (T-4) auction.

13. It is recognised that having auctions further out than four years would help to bring forward technologies that take longer to build, such as storage. However, the further out that auctions are held, the greater the uncertainty for the Government in estimating the volume of capacity needed to deliver the reliability standard. Given that modelling shows new build is predominantly needed from new gas build, which can be built within 3-4 years, holding the auction at (T-4) achieves an appropriate balance between giving certainty about capacity prices to investors and giving Government greater certainty about the volume of capacity needed.

Competition in the auction

14. The main advantage of having the principal auction at (T-4) is that it allows new build to obtain a capacity price before committing to building plant. To participate in a (T-1) auction, by contrast, a new build would have to take a greater risk that the price in that auction would be high enough to cover the plant's fixed costs. Moreover, the

plant would be worried about setting the price in that auction at the 'true' cost of new entry as the plant has already been built by that time; therefore, if the plant were unsuccessful in that auction, it would remain operational but not receive any capacity payments.

15. A further benefit to having forward auctions is that it allows new build to compete against existing plant in the auction, providing an incentive to existing economic plant to not offer capacity above the cost of new entry. New build would replace existing plants if existing plants were to bid above the cost of new entry. In this way the market is contestable – although there is residual risk of gaming by existing plant up to the cost of new entry (which is why a range of other mitigation measures – such as obligations on existing plant to act as price takers - have been put in place). Experience from the Californian energy crisis in 2001 shows that where an energy-only market has underinvested in capacity, existing generators gain significant market power and so can increase prices for several years until new capacity has been brought to market.
16. Segmenting the market into two auctions carries some risk. It means that existing plant or DSR may be able to set a high price in the (T-1) auction if they know there is insufficient capacity and no threat of competition from new plant. Moreover, the ability to offer the capacity of existing plant into the (T-1) auction makes it more profitable to withhold capacity from the (T-4) auction in an attempt to drive the price up to the cost of new entry.
17. However, these risks can largely be mitigated through policy design. Where existing plant withholds from the principal (T-4) auction, the demand in that auction will be reduced accordingly, to avoid potential for gaming. Moreover, there are gaming-mitigation measures in the (T-1) auction, including use of a demand curve and price cap as well as rules for existing plant to be price-takers without due justification.
18. Thus, while there is some risk to having a supplementary (T-1) auction given the lack of new build able to participate, this risk is limited and outweighed by the advantages – namely enabling DSR to participate effectively alongside conventional capacity, and allowing the Government to adjust the volume to procure at the (T-1) stage as it has greater certainty about the level of capacity required.

Annex C: Choice of Agreement Length

1. The maximum contract length available to new build capacity is 15 years. The maximum contract length available to a refurbishing plant is 3 years, while all existing generation and DSR projects will only be eligible for a 1 year agreement.
2. New build and refurbishing plants are defined by reference to capex thresholds which are to be determined as an auction parameter ahead of each auction. Long term agreements are only available to such plants bidding in a 4 year ahead auction.
3. Determining the optimal agreement length for capacity involves complex trade-offs. This annex sets out those trade-offs.

Volume risk

4. Long term contracts lock consumers into buying a particular volume of capacity. To the extent that there is uncertainty about future demand and the volume of non-Capacity Market capacity, this creates risks for consumers that they may lock in to a product they do not need. Therefore, the longer a Capacity Market contract the higher the risk of overprocuring.

Price risk

5. Long-term contracts can provide a hedge to both consumers and investors against wholesale price movements and so reduce risk. However, the risk around future capacity prices is not symmetric – there is a far greater likelihood that prices will go down over time than that they might increase. This is because:
   i. Energy market revenues are likely to increase as the impacts of Ofgem's cash-out reforms feed through into strong energy market signals
   ii. New Capacity Market technologies (such as DSR) might come forward that replace OCGT as the marginal plant in the auction
6. Locking in to contracts at today's price may therefore not be good value for money for consumers. Shorter contracts are better where there is an expectation that prices will decline over time. This is because investors heavily discount future revenues – even where provided through fixed capacity agreements – whereas consumers put significant value on avoiding future bill increases. So, while spreading a capacity payment over a long time will reduce the level of capacity payment, consumers would prefer paying more upfront and less in the future, when we expect capacity prices to fall over time.
7. There is a risk that long-term contracts may distort in favour of certain types of capacity. Long-term contracts in a market with falling prices may make it harder to compare the cost of a given long-term contract with equivalent short term contracts. If contracts are assessed on price alone, then the promise of long-term contracts in this scenario risks skewing the market in favour of new build – potentially prompting existing economic plant to close.

Financing risk

8. The arguments above suggest that it is preferable to only offer short contract lengths to existing, refurbishment and new build capacity. However, longer-term contracts are considered necessary for new build generation in order to provide a period of

revenue certainty to allow new investment to come forward. It is apparent from feedback during the EMR consultation that the Capacity Market proposals were not regarded as "bankable" by many independent generators and their lenders. This was largely due to the proposed contract length for new build (10 years) being too short.

9. Under current UK energy market conditions, project finance lenders are unlikely to take any merchant risk, meaning that the revenues supporting debt service must be supported by an agreement. Contract lengths of 10 years are too short to optimise the debt and would lead to a higher price in either amortising debt (repaying the total loan together with interest payments) over the shorter period or, in reducing gearing levels (the proportion of the loan to the total cost), requiring a greater proportion of equity funding (i.e. via shareholders) at higher hurdle rates, thereby raising the overall cost of finance.

10. We assume that increasing the maximum contract length for new build capacity from 10 years to 15 years will significantly reduce financing risk. This is because commercial debt tenors are currently circa 7 to 8 years. Therefore, a 15-year contract length will allow refinancing mid-term (at, for example, year 7). Lenders for the initial 7-year debt term are able to size the debt as if it were over a 13 or 14-year term, since they will be able to assume the debt can be refinanced in the middle of the capacity agreement term and can also structure repayments assuming that a proportion of the debt can be refinanced. Debt service payments will therefore be lower (reflecting debt being effectively amortised over the longer period), reducing the costs to investors.

Defining new and existing plants

11. To offer longer-term agreements to new build, it is important to be able to define what qualifies as new build to ensure that existing plant undertaking routine cyclical maintenance is not able to qualify as new. However, this definition can be less clear-cut than first appears, as new plants can make use of existing infrastructure – sites, transmission connections, and parts – and particular definitions of 'new' can therefore run the risk of perversely incentivising investors to not make efficient use of existing resources.

12. For this reason, the definition of 'new build' has been set on a technology-neutral basis according to the level of capital expenditure involved in a project – i.e. that an investor has to spend broadly the same amount as if building a new plant from scratch. This avoids technical definitions (e.g. new turbine, greenfield site, or new TEC connection) that could cause parties to not make efficient use of existing resources.

13. The threshold proposed is that new build must involve capital expenditure of at least £250/kW. As can be seen from the table below, this is based on the lower range of estimates of capital expenditure for OCGT plant – which is itself the least capital-intensive form of generating capacity. This is low enough to ensure that the threshold does not cause inefficient spend, but that it is still high enough to avoid existing plant undertaking more modest forms of refurbishment from being able to attain long-term contracts.

Table 12: **Cost of building new gas plant and fitting SCR equipment, £/kW**

	Low	Central	High
Net Power Output (MW)	561	565	608
Pre-licencing costs, Technical and design (£/kW)	16	19	25
EPC cost (excluding interest during construction) (£/kW)	218	274	330
Infrastructure cost (£/kW)	12	16	18
Total (£/kW)	**247**	**309**	**373**

Source: PB Power[68]

14. It is recognised that some existing plant may need to spend significant amounts of capital on refurbishments in order to keep that plant open. We consider that longer-term contracts should be offered to such plant; however, only plant undertaking the most extensive refurbishments should qualify. On the basis of data received from published reports, industry and internal estimates of refurbishment costs, DECC consider that a threshold of £125/kW will allow the most expensive refurbishments to qualify, whilst not allowing plant undertaking more routine refurbishments to access long-term contracts. Plant making refurbishments above the threshold of £125/kW will be offered agreements of up to 3 years.

15. This threshold is based on the lower end of estimates of the cost of fitting Selective Catalytic Reductions (SCR) on coal plant (which reduces their emissions and allows them to stay open longer under the Industrial Emissions Directive). The refurbishment threshold has been set according to the cost of SCR as this is clearly an exceptional form of investment for existing plant and so sets the bar sufficiently high so as to mitigate the risk that existing plant is able to qualify as refurbishing plant for undertaking routine cyclical maintenance.

Conclusion

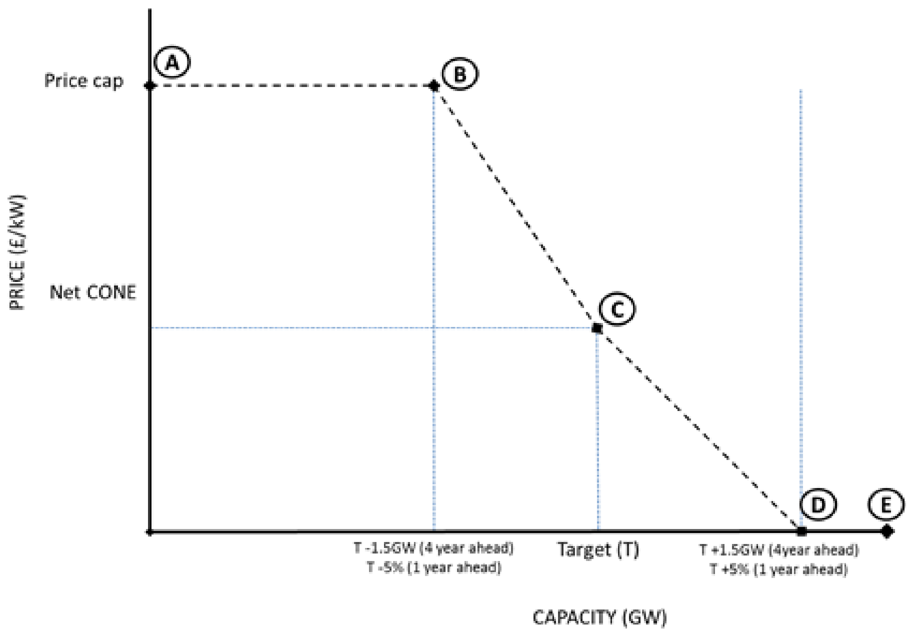
16. The issue of contract length is a complex one. The final policy design is for the maximum contract length available to new build capacity to be 15 years and for the maximum contract length available to refurbishing capacity to be 3 years. We assume these contract lengths will significantly reduce financing risk. We also assume there is little benefit to further increasing maximum contract lengths.

[68] Electricity Generation Cost Model – 2013 Update of non-renewable technologies, PB Power

Annex D: Demand Curve

1. The demand curve for the capacity auction will be a line passing through each of the following points, as shown in the figure below:
    i. Price cap of £75/kW at a capacity of 0GW (Point A in the table below)
    ii. For the four-year ahead auction, the price cap (£75/kW) at a capacity 1.5GW less than target level. (B)
    iii. Net cost of new entry (Net CONE) at the target level of capacity. (C)
    iv. For the four-year ahead auction, £0/kW at a capacity 1.5GW more than the target level. (D)
    v. Where the price is zero, as much capacity is available will be contracted (E).

Figure 7: **Illustrative Demand Curve**



Net Cost of New Entry (Net CONE)

2. Net CONE is the central administrative estimate of the level of capacity payment needed to incentivise new build. This sets the price at which Government is willing to buy the target volume of capacity – with more bought if the capacity price is lower and less bought if the capacity price is higher than Net CONE.
3. In the October 2013 Capacity Market Impact Assessment, Net CONE was based on the level at which a new build large scale OCGT was expected to be able to bid into the first auction. However, we now believe that it is unlikely that large scale OCGT will be able to be built in time for the first delivery year (2018/19). Therefore, for the first auction, Net CONE is based on the estimated level at which new build CCGT will bid into the Capacity Market. This takes account of energy market revenue and ancillary service payment. The result is that Net CONE has increased from £29/kW to £49/kW.

Price Cap

4. The price cap sets the maximum price at which we are willing to procure capacity. The EMR consultation proposed a price cap of either £44/kW or £75/kW. Feedback from the consultation suggested that a price cap of £44/kW would be too low and would limit the amount of capacity being offered in the auction.
5. Analysis also suggests that a price cap of £44/kW may limit the amount of capacity being offered in the auction. Previous modelling for the June 2014 IA carried out a stress test. This stress test assumed that new build CCGT would bid into the Capacity Market at a higher price than is assumed in the central scenario. In the stress test it was assumed that new build CCGT have higher capital costs and a higher hurdle rate. As a result, the stress test modelling estimated that new build CCGT bid into the Capacity Market at £73/kW.
6. Based on analysis carried out by DECC and feedback during the EMR consultation the price cap for the first auction will be set at £75/kW.

Price Taker Threshold

7. Another important measure to mitigate gaming risk in the auction is to require existing plants to offer capacity below a low threshold or else be prepared to provide a justification (authorised by the company's board) for why the higher offer price is required. This justification can subsequently be used by Ofgem as evidence in an investigation.
8. This measure is needed as most existing plant will have costs that are lower than new entry and so may seek to exercise market power to set a high price in years where new entry is not needed. However, it is also recognised that some plants will reasonably need to demand a high price in the auction – for instance if they are old plants in need of significant maintenance costs. The price taker threshold therefore needs to balance the administrative burden of requiring existing plant to submit a business case in order to bid above the threshold, with the risk of gaming if existing plant are able to price high without good justification.
9. The price taker threshold should be set at a level that captures the majority of existing plant, while being at a price low enough to mitigate gaming. The price taker threshold has been set at 50% of Net CONE for the first auction. The modelling suggests that this will capture 80% of existing plant.
10. In practice there is uncertainty to the level of support that existing plants would require. For instance:
    i. Plants may bid higher if they seek additional payment to compensate for additional risk they are taking on by holding capacity payments;
    ii. Plants may bid lower if they think that there are likely to be 'scarcity rents' due to prices rising to VoLL at times of stress; and
    iii. Plants that are currently making losses in the energy market may seek a higher level of payment in the first auction in 2014 to justify staying open until the first delivery year in 2018/19.

11. However, while there is uncertainty around how plants need to bid into each auction, a threshold of 50% of Net CONE should strike an appropriate balance between preventing existing plant from pricing high into the auction while ensuring that only a small fraction of existing plants should need to qualify as price makers.
12. The price taker threshold can be reviewed prior to further auctions if evidence from the auction suggests it should be lower or higher or if Net CONE is changed.
13. Below the price taker threshold, competition between existing generators should still provide some downward pressure on bidding behaviour – with existing plants incentivised to bid in close to their marginal cost if they think that the auction is sufficiently competitive. Allowing existing plants to set the price up to the price taker threshold equal to a fraction of Net CONE is consistent with the practice in other major capacity markets, including in PJM and ISO-New England.

Annex E: Eligibility Rules for Participation in the Capacity Market

Rationale for Market-Wide Mechanism

1. The Capacity Market is intended to be a market-wide and technology-neutral mechanism.
2. The rationale for this approach was set out in the 2011 Impact Assessment that considered a more targeted form of intervention ("Strategic Reserve"), which only paid for additional capacity to be used in exceptional circumstances.[69] This analysis concluded that there were strong advantages to having a market-wide mechanism, particularly one that included existing plant as well as new:

   - Missing money: In the energy market, all plant are able to sell their energy at the same price – and so all plant face the same "missing money" due to energy prices not adequately rewarding capacity at times of stress.

   - Making use of existing capacity: Any decision to exclude existing plant forces Government to have to assess the volume of existing capacity that will stay open without support. Moreover, since the Capacity Market has potential to dampen wholesale prices it also risks prompting existing plant to close prematurely. By contrast a market-wide mechanism is technology-neutral – letting new and existing plant compete against each other so the most economic plant wins. This means that a market-wide mechanism can be more cost-effective, as it avoids over- or under-procuring new capacity and ensures economic existing plant is kept open.

   - Avoid regulatory risk: If the Capacity Market reduces wholesale prices, then it may reduce the degree to which existing generators can recover their fixed costs. This creates two potential regulatory risks. The first is that it may prompt investors to demand a higher return on new build, as they perceive a greater regulatory risk around the Government not letting investors realise the value of their plants over the long run. The second risk is that a number of existing plants could threaten to close if they do not become eligible for payment – leading to a "slippery slope" of paying everyone a capacity payment without having a structured competitive procurement process to ensure value for consumers.
3. However, three categories of capacity have been excluded from participation in the Capacity Market. These are:

   i. plant receiving low-carbon support,

   ii. plant receiving certain long-term contracts for the Short Term Operating Reserve (STOR), and

   iii. interconnected capacity.

   This annex sets out the rationale for these exclusions.

[69] https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/42797/3883-capacity-mechanism-consultation-impact-assessment.pdf

Exclusion of plant receiving low-carbon support

4. Low-carbon plant receiving support will be excluded from the Capacity Market to avoid any risk of overpayment.[70]

5. The rationale for this is that the level of support through each mechanism has been set at the minimum level of support that can bring forward sufficient investment in low-carbon capacity. Providing additional support through the Capacity Market creates potential for overpayment or overinvestment in particular technology types. However, if low-carbon technologies choose not to receive support through these mechanisms, then they will remain eligible to receive support through the Capacity Market.

6. There are however significant differences between support mechanisms:

   i. <u>Contracts for Difference (CFD)</u>: The CfD rewards plants on the basis of their energy generation. However, the strike price for the CfD will be set to incentivise sufficient investment in capacity. It would be possible to include CfD-supported plant and avoid overpayment if the CfD strike prices were set at a lower level to reflect the value of capacity payments. However, this would then introduce a new uncertainty into the setting of CfD strike prices, increasing the risk of making incentives either insufficient or overly generous. In future, once CfD strike prices are set competitively (rather than through an administrative process), it may be possible to allow new CfD plant to participate in the Capacity Market.

   ii. <u>Small-Scale Feed-In Tariffs (FITs)</u>: This mechanism supports embedded low-carbon generation (such as solar panel installations) by providing a fixed price for generation that does not vary with the market price. This level of support clearly has no interaction with the Capacity Market and so participation in the Capacity Market would constitute overpayment, relative to the levels of support that were originally intended through the FIT.

   iii. <u>Renewable Obligation (RO) plant</u>: Plant receiving support through the RO are exposed to changes in the wholesale price. While some existing plant may be slightly negatively affected if the Capacity Market reduces wholesale prices, this impact is likely to be small and far lower than the windfall that existing RO-plant received through the introduction of the Carbon Price Floor (the impact of which was not anticipated in previous banding reviews). This emphasises an important principle in setting RO support – that support levels are not amended retrospectively, so it would not be appropriate to provide existing RO plant with capacity payments.

[70] Although they may be eligible to participate in the Capacity Market once they cease receiving low carbon support, such as on expiry of the CfD or RO contract.

iv. Renewable Heat Incentive (RHI): Renewable Combined Heat and Power (CHP) projects are eligible for RHI payments for their heat generation and RO payments for their electricity generation. These levels of support have been set so as not to require additional support. It would therefore be inappropriate for this capacity to additionally be eligible for capacity payments.

7. The decision of how much capacity to procure in the Capacity Market needs to take account of capacity excluded from the mechanism. It is recognised that exclusion of the above groups of capacity introduces additional uncertainty in the decision of how much capacity to procure, as it is necessary to estimate how much capacity will come through these alternative mechanisms. However, this is judged to be an acceptable trade-off to avoid overpaying for low-carbon technologies seeking support through multiple schemes.

Exclusion of plant receiving certain long-term contracts for the STOR

8. Plant receiving certain long-term contracts for the provision of STOR can elect to continue to receive their STOR contract or participate in the Capacity Market. The relevant 'long-term' STOR contracts are:

    i. Contracts which were entered into before the date on which the Electricity Capacity Regulations 2014 come into force, and

    ii. which expire after the start of the delivery year

9. At the time such long-term (15 year) STOR contracts were awarded in 2010 the proposals to introduce a capacity mechanism had not been put forward. As such little value could have been credibly ascribed to potential capacity payments by the STOR bidders. Therefore, the level of support from these STOR contracts was deemed sufficient to incentivise new capacity to come forward in the absence of capacity payments. In contrast annual STOR prices are reset annually and competitive forces will ensure providers can take account of their Capacity Market revenue streams when pricing their STOR bids – so that their total revenue remains broadly constant. Therefore, allowing plants with long-term STOR contracts to receive both their STOR contract and a payment from the Capacity Market would be double payment, especially as there is no mechanism for plants to adjust their long-term prices commensurately with any capacity payments.

Exclusion of Interconnected Capacity

10. In theory it would be desirable for overseas capacity to be able to participate in the Capacity Market on the same terms as GB generation. This would enable greater competition in the auction and ensure that the mechanism does not introduce any distortions to investment signals – e.g. where in Europe capacity should be situated or to how much interconnection should be built between GB and other markets.

11. However, there are also significant practical difficulties to allowing for the inclusion of interconnected capacity in to the Capacity Market. These include:

- Verification: It would be necessary to have international cooperation between domestic System Operators so that the physical capacity of plant situated outside of GB can be verified, as well as their delivery of energy at times of stress. Assessing whether parties overseas have delivered energy at times of stress may be complex, as they will be participating in a different energy market – for instance, they may be constrained due to local constraints.

- Additionality: It would be difficult to assess the appropriate derating of interconnected plant, where their contribution is significantly limited by the transmission constraints between them and the GB market, and where interconnectors may be flowing out of GB as well as in at times of stress.

- Eligibility: We have excluded from the Capacity Market plant already in receipt of particular types of support to avoid the risk of overpayment. However, different markets in Europe may each have their own set of support schemes and there will be complexity in assessing whether capacity overseas would be overpaid if they received capacity payments in GB.

- Compatibility with the Target Model: It is the objective of the Target Model to ensure that interconnector flows are determined implicitly by price differentials between the markets, rather than explicitly through procurement of physical transmission rights over the interconnector. This means that it is not possible to identify whether any particular plant has directly contributed to interconnector flows. It would therefore be very difficult to impose a Capacity Market penalty on a non-GB generator if it had delivered in its home market, but the interconnector from that market to GB was not delivering energy (and hence its capacity) to GB. This could potentially also result in out of merit dispatch in the foreign market. Given this, it is difficult to see how the treatment of non-GB plant could be equitable with GB plant, as when a GB-based plant delivers it primarily delivers its energy (and capacity) onto the GB system.

12. While the Capacity Market will be introduced without foreign plant being able to participate, we are continuing to work with industry and other Member States to find a suitable proposal for including interconnected capacity in future that addresses the issues above.

Annex F: Rules for Applying Penalties

1. Previous analysis – in Annex A of the Capacity Market IA issued in November 2012 – addressed the decision to set penalties for capacity providers that fail to deliver energy at times of system stress.[71] This analysis focuses on two key elements in relation to penalties – the level of VOLL and the imposition of a penalty cap.

Rationale for having penalties

2. The penalty regime in the Capacity Market serves two main purposes:

    i. Performance Incentives: The Capacity Market gives providers a stable payment but reclaims this money in the event that providers fail to deliver energy at times of system stress. In an efficient energy-only market, prices would rise to VoLL at times of stress, providing generators with a powerful incentive to be available at those times and to invest in the reliability of their plant. An important principle of the Capacity Market design has been that the incentives created should, wherever possible, mirror the incentives that would exist in an efficient energy-only market.

    ii. Adjusting of capacity value: The presence of sharp penalties for failure to deliver energy at times of system stress provides an incentive for participants in the auction not to offer unreliable capacity into the auction. This ensures that the mechanism procures the plant mix that is best value for consumers (rather than plants that are least-cost in the auction but have little ability to deliver energy when needed). In practice, the capacity value of plants will be administratively determined (within bands) and there will be some degree of uncertainty when setting the derating for each plant, with deratings overestimated for some plant and set too low for others. The penalty regime – with rewards for overdelivery and penalties for underdelivery – should ensure that, over time, the overall levels of payment for each plant match the value of the capacity that plant offers.

Design of the penalty regime

3. The penalty regime aims to reintroduce the incentives not currently present in the market due to "missing money". Missing money principally occurs at times of lost load when the price in a perfectly efficient energy-only market should rise to VoLL (estimated in GB to be £17,000/MWh). In practice, this is significantly above past prices (which have not been seen to rise above £1,000/MWh) and announced proposals for cash-out reform (which will introduce a £6,000/MWh scarcity price signal).

4. The level of missing money is therefore estimated as VoLL minus the prevailing cash-out price. Assuming that cash-out in future rises to £6,000/MWh, the level of missing money at times of system stress will be £11,000/MWh.

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

5. However, there is a trade-off between having penalties that reflect the full degree of missing money and reducing risk for investment in new capacity. In an energy-only market it is necessary for scarcity signals to fully reflect VoLL, in order to ensure there are sufficient incentives for investment in new capacity. Having a separate capacity payment, the introduction of a Capacity Market allows for investment to be remunerated in a way that is less risky for investors – mitigating the significance of performance risk. This is achieved in two ways:

   i. Cap on liabilities: Unlike in an energy-only market, liabilities in the Capacity Market will be capped in proportion to their capacity payment.

   ii. Lower level of VoLL: It is assessed that incentives do not need to reflect the full VoLL, as performance incentives will still be very strong if lower; a lower penalty rate still enables payment to unreliable plant to be reclaimed.

Nature of cap on liabilities

6. The cap on liabilities has been designed so that once plants have hit their liability cap they can still "roll back" their penalties in subsequent events. This ensures that plants always retain strong incentives to deliver.

Level of liability cap

7. In an energy-only market, capacity would have to be available and generating at times of lost load to earn the market revenues equivalent to the missing money. Hence, the annual penalty cap level should at least be 100% of annual capacity payments in order to mimic energy-only market incentives.

8. In addition, we consulted on setting the annual penalty cap above 101% to minimize the risk of gaming in the Capacity Market. This would prevent Capacity Market participants (existing capacity) that never intended to perform in the Capacity Market from taking a gamble, with the expectation of receiving capacity payments without facing significant loses. This should ensure value for money to consumers.

9. It is recognised, however, that there is an inherent balance to be achieved between a penalty mechanism which does not give 'free money' to unreliable plant, yet which enables debt to be raised on the back of Capacity Market revenues. The former necessitates a high penalty rate and high liability cap, whilst the latter requires a low penalty rate and a low liability cap.

10. The high rate/cap combination is likely to discourage the participation of inefficient or 'cardboard plant', but is also likely to result in risk premia being priced into the auction bids of new build and existing plant with an average reliability. Whilst the competitive nature of the auction should prevent excessive premia being applied, an overly punitive regime, especially where inefficient plant could lose more than they receive in capacity payments, would result in higher premia being priced in across the board. It is also a concern that a punitive regime may discourage the participation of prospective plant, particularly where their debt service conditions require premia to be priced into auction bids that may take the bids above the auction price threshold, or where the lenders' risk aversion is such that they are potentially unwilling to lend to projects subject to such a risk profile, unless it can be effectively managed.

11. We have therefore decided to introduce a monthly liability cap of 200% of monthly capacity revenue, in the overarching context of a 100% annual cap, as an appropriate way of smoothing a provider's risk exposure over the entire year, and thereby mitigating the risk of significant penalty exposure resulting from one failure.

12. Considering the very low probability of numerous stress events across multiple months in any one year, it is proposed that the combination of a 200% monthly cap and 100% annual cap (where providers have proportionally more at risk in any month, but annual liability is capped at their annual revenue level) offers a better balance than a lower monthly cap/higher annual cap combination (where providers can only lose a minimal amount for any one event, but could lose in excess of their annual revenue for multiple failures). Although we expect in many years there to be a limited number of stress events, even a 200% monthly cap risks over-rewarding unreliable providers - if a plant failed to deliver in three separate stress events that fell in three separate months, the maximum penalty would only be 60% of its annual capacity payments. This is why we have introduced additional testing for potentially unreliable plants.

13. One of the key concerns of project finance providers is their cumulative penalty exposure for periods of unscheduled maintenance, especially as regards their liability in the c.45 day excess period before their Business Interruption insurance starts to pay out. Consideration was initially made of having a monthly cap of c.400% of monthly revenue, within the context of a 100% annual cap, to provide more robust delivery incentives. However, under such an approach the level of financial reserves that a project-financed provider would need to carry, in order to cover their liability over the 45 days (two months' capacity liability), could be as high as 80% of annual capacity payment revenue. This may be of a similar level to their annual debt service, potentially putting the project into default through a single technical fault before the Business Interruption Insurance kicks in. This situation is likely to raise a significant barrier to the bankability of the mechanism.

14. In the case of a 200% monthly cap, the level of financial reserves would be a more manageable 40% of their annual capacity revenue. Representation from industry stakeholders suggests this reserve would be required, irrespective of the low probability of two such events occurring in the 45 day period.

15. We also consulted on the level of the Capacity Market penalty rate, between the range £1,000-£3,000/MWh. As a result of Ofgem's cash-out decision (i.e. that cash-out prices reach £6,000/MWh in times of system stress), the energy market will have strong performance incentives, with the Capacity Market penalty rate representing a 'top-up' to the cash-out price.[72] Whilst the objective of the penalty rate is to reduce the amount of capacity payments and penalise Capacity Market participants that do not perform as required, by providing levels of reliability below their de-rating factors, topping-up the cash-out price signal with a higher penalty rate (greater than £3,000/MWh) would provide minimal benefit in terms of performance incentives (as a £6,000/MWh signal is already sufficiently high).

[72] https://www.ofgem.gov.uk/publications-and-updates/electricity-balancing-significant-code-review-final-policy-decision

16. The final formulation of the penalty rate (the relevant auction clearing price divided by 24) ensures that all providers failing to deliver as per their scaled obligation would progress towards their respective liability caps at the same rate, irrespective of which auction they had cleared in. This would not have been the case if a fixed £/MWh rate (e.g. £3,000/MWh), independent of the level of capacity payments, was utilised. This approach also facilitates the calibration of the penalty rate in terms of the duration of non-delivery required to reach the relevant liability cap, with the 1/24th approach resulting in all failing providers reaching their monthly liability cap in circa four hours (noting it varies between months depending on the payment weighting applied to each based on projected system demand). Four hours was considered an appropriate balance between ensuring consumer value for money and the likely profile of frequency and duration of system stress events. It also ensures that the £/MWh rate takes account of Ofgem's cash-out decision (for cash-out price signals of £6,000/MWh at times of system stress) and that the rate is broadly in the range of the rates consulted on for all potential auction clearing prices; the highest permissable clearing price (auction price cap of £75/kW) results in a penalty rate of £3,125/MWh. For comparison a clearing price of £40/kW would result in a penalty rate of £1,667/MWh being applied to all the capacity which clears in that auction.

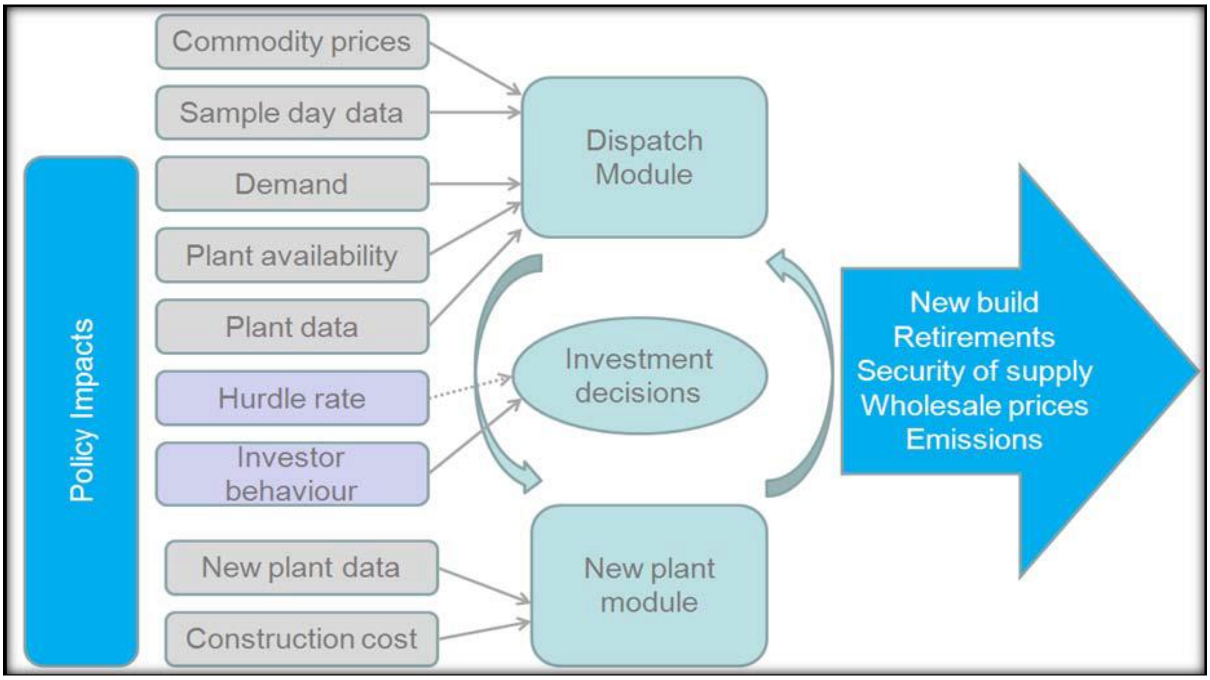
Annex G: Energy System Modelling

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 considers electricity demand and supply on a half hourly basis for sample days. Investment decisions are based on projected revenue and cashflows allowing for policy impacts and changes in the generation mix. The full lifecycle of power generation plant is modelled, from construction through to decommissioning. 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

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

Figure 8: **Structure of the Dynamic Dispatch Model (DDM)**



3. 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

4. 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 offshore wind. The generation data includes

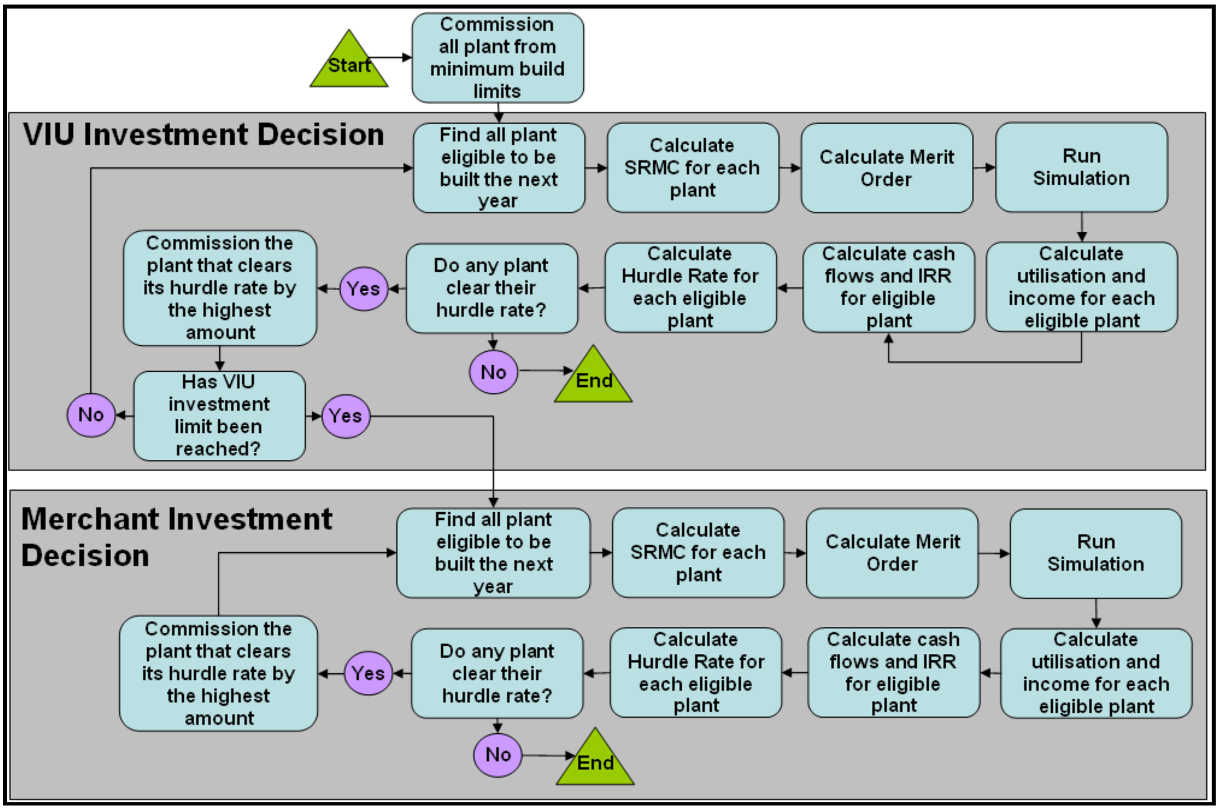
outage rates, efficiencies and emissions, and also planned outages and probabilities of unplanned outages.

5. 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, autogeneration 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

6. 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 the figure below. Limitations can be entered into the model such as minimum and maximum build rates per technology, per year, and cumulative limits.

Figure 9: **Investment decisions in the DDM**



Policy Tools

7. 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 cashflows 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, only new plants or include existing plants and be varied over time and duration. Policies can be financed through Government spending/taxation or charged to consumers.

Outputs

8. 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. Using these outputs a Cost Benefit Analysis is carried out on the model run including a distributional analysis.

9. The DDM therefore enables analysis to be carried out on policy impacts in different future scenarios, allowing DECC to consider and compare the estimated impacts of different potential policies on the electricity market.

Peer Review

10. The model was 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. For the Peer Review report see 'Assessment of LCP's Dynamic Dispatch Model for DECC' (http://www.decc.gov.uk/assets/decc/11/about-us/economics-social-research/5427-ddm-peer-review.pdf).

Levy Control Framework

11. On 23 November 2011, the Government agreed a Levy Control Framework (LCF) to 2020, which is set at a total of £7.6bn (in real, 2012 prices).[73] This will help diversify our energy mix by increasing the amount of electricity coming from renewables, as well as supporting new nuclear power and carbon capture and storage commercialisation. It also helps to provide certainty to investors across a range of generation technologies and protection to consumers.

Scenario-based analysis

12. The baseline for DDM analysis represents a plausible outcome of Electricity Market Reforms, characterised by a diversified supply mix[74] and an assumed carbon

[73] http://www.decc.gov.uk/en/content/cms/news/pn12_0146/pn12_0146.aspx

[74] Diversification reflects (in part) the objective of support for the development of a portfolio of low-carbon generation technologies, in order to reduce the technology risks associated with the decarbonisation objective for the power sector

emissions intensity of $100gCO_2/kWh$ in 2030, which is an illustrative level of decarbonisation in the power sector, consistent with previously published EMR impact assessments.

13. Dispatch modelling is sensitive to a number of such assumptions (e.g. around inputs, methodology), 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 be a prediction or forecast about what the future is expected to be.

Input assumptions

Fossil fuel price assumptions

DECC's fossil fuel price assumptions are used in the DDM as set out below to 2030. Details can be found at https://www.gov.uk/government/publications/fossil-fuel-price-projections-2013

2012 prices	Oil			Gas			Coal		
	$/bbl			p/therm			$/tonne		
	Low	**Central**	**High**	**Low**	**Central**	**High**	**Low**	**Central**	**High**
2012	112	112	112	60	60	60	92	92	92
2013	93	108	122	53	62	72	85	90	94
2014	92	109	126	51	65	86	86	96	105
2015	91	110	129	48	68	89	87	102	110
2016	89	112	132	46	69	91	88	106	116
2017	88	113	136	44	71	93	88	109	121
2018	87	114	140	41	72	96	89	113	126
2019	86	116	143	41	72	98	90	117	131
2020	84	117	147	41	72	101	91	120	136
2021	83	119	151	41	72	103	91	120	142
2022	82	120	155	41	72	103	91	120	147
2023	81	122	159	41	72	103	91	120	152
2024	80	123	163	41	72	103	91	120	157
2025	79	125	168	41	72	103	91	120	162
2026	78	126	172	41	72	103	91	120	162
2027	77	128	177	41	72	103	91	120	162
2028	76	129	181	41	72	103	91	120	162
2029	75	131	186	41	72	103	91	120	162
2030	74	132	191	41	72	103	91	120	162

Carbon Prices

The DDM uses DECC's appraisal values for carbon, as set out below.

DECC appraisal values for greenhouse gas emissions impacts in the traded sector, 2012 £/tonne of CO_2e

	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Central	6	3	4	4	4	4	4	4	5	12	19	26	33	40	47	54	61	68	75

In addition to this the Carbon Price Floor is included in the model following the trajectory set out in the government's response to the consultation on the Carbon Price Floor:
http://www.hm-treasury.gov.uk/d/carbon_price_floor_consultation_govt_response.pdf

Carbon Price Floor, 2012 £/tonne of CO_2e

2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
7	12	19	20	20	20	20	20	27	34	41	47	53	58	62	66	70	75

Technology Assumptions

Cost and technical data for new plant is taken from DECC's Electricity Generation Costs 2013 report for all renewable and non-renewable technologies. Details can be found at:

https://www.gov.uk/government/publications/electricity-generation-costs

Electricity Demand

The DDM uses Electricity Demand from the 2013 Updated Emissions Projection (UEP). These can be found in Annex C of the following link:

https://www.gov.uk/government/publications/updated-energy-and-emissions-projections-2013

Note: The UEP numbers are then adjusted downwards by 2.7% before use in the DDM model as they include Northern Ireland, while the DDM models Great Britain alone. Northern Ireland is reflected in the modelling through the analysis conducted by National Grid and the System Operator Northern Ireland (SONI).

Limitations of the modelling

14. There are important limitations to the modelling. Two significant ones from a security of electricity supply perspective are:

- It 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 greater than the risks of building too much, so the economically efficient capacity level is higher in reality.
- It doesn't model the effects of plants needing to be warm in order to operate. As a result, it may underestimate the likelihood of scarcity events or prices rising above marginal cost when margins are wide. It also fails to reflect the effect of cash-out reform on the degree of plant warming or on the market incentives to invest in plant faster ramp-up times.

Capacity Market

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

16. 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 derated capacity to the auction. However, low-carbon plant in receipt of payment through the RO and CfD is not eligible for capacity payments.

17. 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.

18. 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, derated by the standard capacity credits in the Electricity Market Reform modelling. From this 'stack', the auction clearing price for each year is calculated, along with which plant receive the reliability contracts.

19. The key parameters for a modelled Capacity Market are:

- For delivery years 2019/20 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 as well as interconnected capacity are assumed to not receive capacity payments, although their capacity credit is taken into account when setting the level of capacity to contract for.
- Contract length: 1-year contracts for existing plant and fifteen-year contracts for new plant.
- Once a generator has physically closed it cannot re-enter the auction in a later year – i.e. the possibility of mothballing capacity has not been considered.
- Generators offer their capacity factors into the auction.
- All plant operating under the Limited Lifetime Opt-out (LLO) mechanism must close in 2023.