Redpoint

A business of Baringa Partners

Estimating the costs and benefits of the Capacity Market

A report to the Department of Energy and Climate Change

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Version History

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Introduction

The EMR Capacity Market is the UK Government's main proposed policy measure to promote security of electricity supply in Great Britain (GB). In October 2013, DECC published the EMR Consultation on Proposals for Implementation. This document includes the full details of the current proposed design for the Capacity Market. Alongside the October 2013 consultation document, DECC published an Impact Assessment for the Capacity Market, which was an update on that previously published in July 2013.

Purpose of the study

Redpoint Energy (a business of Baringa Partners LLP) was commissioned by DECC to undertake a review of the Capacity Market Impact Assessments, involving an independent assessment of the costs and benefits of the proposed GB Capacity Market and a comparison to the results of DECC's own analysis. The objectives of this study were to confirm, or otherwise, the broad conclusions of DECC's analysis, identify any gaps in its modelling approach, and explore variables that can affect the results.

Approach

The comparison was undertaken for both the July 2013[1] and October 2013[2] Impact Assessments. The analysis was performed in Redpoint's Investment Decision Model (IDM) which, like DECC's own Dynamic Dispatch Model (DDM), is an agent based simulation model which captures market dispatch, and endogenous investment decision making. Although methodologically similar, the models differ in a few key areas, for example the granularity of dispatch, the pricing function (particularly the relationship between prices and capacity margins) and the modelling of interconnectors.

In general we used DECC's assumptions to construct the scenarios for the modelling, rather than Redpoint in-house views. The one exception to this was on plant availabilities. For some technologies, DECC assumes a higher annual availability than peak de-rating factor, which when adopted in the Redpoint model can produce anomalous results. Hence, for annual plant availabilities we assume the DECC annual availability or peak de-rating factor, whichever is the lower value.

Outputs from the model include plant build and retirements, de-rated capacity margins, Capacity Market clearing prices, wholesale electricity prices and carbon dioxide emissions. Low carbon build was fixed to be the same as in the DECC modelling, ensuring that the 2020 renewables targets are met and carbon intensity in the power sector is approximately 100gCO_2/kWh by 2030.

Results

In both the DECC and Redpoint modelling the Capacity Market serves to reduce periods of low capacity margin and hence reduce the risk of demand not being met (unserved energy). In the DECC modelling the

[1] DECC, Capacity Market Impact Assessment July 2013, https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/225981/emr_delivery_plan_ia.pdf

[2] DECC, Capacity Market Impact Assessment October 2013, https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/252743/Capacity_Market_Impact_Assessment_Oct_2013.pdf

absence of the Capacity Market leads to persistently low capacity margins, whereas in the Redpoint modelling the capacity margin is more volatile without the Capacity Market.

The Redpoint modelling (using the October 2013 assumptions) suggests a small overall decrease in net welfare over the period 2013-2030 associated with the Capacity Market (the savings in reduced unserved energy do not cover the costs of the additional generation capacity), and an increase in bills, averaging around £5 annually for a typical domestic customer. The DECC modelling shows a modest net welfare benefit, but a higher cost to consumers, around £13 annually for a typical domestic consumer. These results using the October 2013 Impact Assessment assumptions are summarised in Table 1 below.

Table 1 Summary CBA and bill impact results (real 2012)

	DECC	Redpoint
Net welfare NPV (NPV 2013-2030, £)	450	-190
Annual average domestic consumer bill impact (2016-2030, £)	13	5

The major areas of differences can be traced back to the different responsiveness of wholesale prices to tight capacity margins in the two models (DECC's DDM is less responsive), which results in different outcomes in terms of consumer bill impacts and in generation mix. In particular, the cost to consumers is very sensitive to this modelling parameter.

Conclusions

The comparison of the DECC and Redpoint modelling suggests that the overall impact of the Capacity Market on net welfare is likely to be modest; a small net dis-benefit in the case of the Redpoint modelling, a small net benefit in the case of the DECC modelling. The results are sensitive to input assumptions and we would recommend further sensitivity testing. For example, the Redpoint analysis using the July 2013 Impact Assessment assumptions showed a small net benefit from the Capacity Market, a key difference from the October 2013 assumptions being a lower contribution to security of supply coming from interconnectors. This result suggests that the economic case for the Capacity Market is stronger where interconnectors cannot be relied upon to import under conditions of system stress in the GB market.

Both sets of analysis suggest additional costs to consumers as a result of the Capacity Market, although we believe that the DECC analysis may overstate this cost since in the DECC DDM wholesale electricity prices are relatively insensitive to the lower capacity margins that we may see in the absence of a Capacity Market. Again, costs to consumers are sensitive to input assumptions with particular risk factors being the capacity requirement being over-estimated (for example, the peak demand forecast four years ahead being too high), or larger than expected risk premia in participants' bids into the capacity auctions. Further sensitivity testing in this area would be beneficial.

1 Introduction

Redpoint Energy (a business of Baringa Partners LLP) was commissioned by DECC to estimate the Costs and Benefits of the proposed GB Capacity Market and compare the results to DECC's own analysis for the Impact Assessments published in July 2013[3] and October 2013[4]. The analysis was performed in Redpoint's Investment Decision Model (IDM), described in Appendix B. The scenarios were constructed using DECC's own scenario assumptions, and the outputs of the modelling were compared to the results from DECC's own Dynamic Dispatch Model (DDM).

This report is structured as follows:

- Section 2 presents background to the Capacity Market, DECC's own modelling and the scope of our analysis;
- Section 3 describes the approach to the modelling, and the assumptions used in modelling the Capacity Market;
- Section 4 describes the results of the modelling based on the October 2013 Impact assessment, and makes comparisons to DECC's DDM results; and
- Section 5 presents our conclusions.

The appendices include additional results based on the July Impact Assessment assumptions and a description of the Investment Decision Model.

1.1 Baringa Partners

Baringa Partners is a specialist consultancy of 300 professionals dedicated to the Energy, Water and Financial Services sectors with bases in the UK and Germany. Our work is focused on delivering change within our industries, including supporting our clients in formulating strategy and making key decisions, and in the delivery of transformation programmes across business and information technology.

Since our formation in 2000, we have grown strongly, working with some of the largest energy producers, utilities and banks across Europe, as well as niche and innovative start-ups. We have continued to attract some of the brightest talent across our industries, and have been widely recognised as an employer of choice.

Our Energy Advisory Services practice, formed through the merger with Redpoint Energy in April 2012, has worked with many of the leading energy companies in Europe, as well as governments and regulators, on issues related to market reform, regulation, strategy, asset acquisition, regulation, restructuring, asset

[3] DECC, Capacity Market Impact Assessment July 2013, https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/225981/emr_delivery_plan_ia.pdf

[4] DECC, Capacity Market Impact Assessment October 2013, https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/252743/Capacity_Market_Impact_Assessment_Oct_2013.pdf

portfolio management, and performance improvement. We are recognised for the depth of expertise in the markets in which we operate and our analytical excellence.

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2 Background

2.1 GB Capacity Market

The EMR Capacity Market is the UK Government's main proposed policy measure to promote security of electricity supply in GB.

In October 2013, DECC published the EMR Consultation on Proposals for Implementation[5]. This document includes the full details of the current proposed design for the Capacity Market. The key features of the Capacity Market relevant to our analysis are summarised below.

Initiating the Capacity Market

The Capacity Market will start with an auction in November 2014, for delivery of capacity from the winter of 2018/19, and will continue to be held on an annual basis for a delivery year four years ahead from that point. Separate Demand Side Response (DSR) auctions are proposed to run in 2015 and 2016, each for delivery one year later. Auctions will also be held one year ahead of delivery to allow for the participation of DSR in the Capacity Market and to adjust the amount of capacity that is holding capacity agreements if required to reflect changes in demand projections between the four year ahead auction and the delivery year.

The amount of capacity to procure

The amount of capacity to procure will be determined by an enduring reliability standard – a draft of which was published alongside the Draft Delivery Plan in July 2013. The Government anticipates that this standard will be expressed as a loss of load expectation (LOLE) which is the number of periods per annum over the long term where it is statistically expected that supply will not meet demand[6]. The draft LOLE published in the Draft Delivery Plan is 3 hours per annum. The EMR Delivery Body (National Grid) will be required to translate the reliability standard into a capacity requirement to propose to the Government for adoption ahead of each auction. The Delivery Body's analysis will be reviewed by the Panel of Technical Experts.

Eligibility

All generators greater than 2 MW will be eligible to participate in the Capacity Market, apart from interconnected capacity (initially), and low carbon generators supported by the CfD or the Renewables Obligation.

Demand side response (DSR), storage and permanent reductions in electricity demand will be eligible to participate. Participation will be voluntary, and that capacity will be able to participate in both the Capacity Market and the Balancing Services markets with the SO (National Grid), as is also the case for generators.

[5] https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/249591/EMR_Consultation_on_Implementation_proposals.pdf

[6] This does not mean that GB would experience this level of blackouts in a particular year; in the vast majority of cases, loss of load would be managed without significant impacts on consumers.

Auctions

The auction will be "pay as clear", and follow a descending clock format, involving bidding "rounds" at different prices, so that the auction discovers a minimum price at which there is sufficient capacity to meet the capacity requirement.

Participants in the auction will have to register as either price makers or price takers. Price maker status is reserved for new plant and DSR, and existing plant that can demonstrate that they require investment for refurbishment, or otherwise require a higher price than the price taker cap. Existing plant wishing to set the price must submit to Ofgem its reasons for wanting to do so, and may be subject to investigation if it is unable to clear in an auction where it attempts to set the price, but continues to operate without a capacity agreement.

The Government will express its willingness to pay for capacity around its target by creating a sloping demand curve for capacity auctions with a price cap. This will enable a trade-off to be made between capacity and cost. It is also designed to mitigate gaming concerns by providing flexibility in the volume to be acquired and a cap to the clearing price.

An important parameter on the demand curve will be the net cost of new entry (net CONE) which will intersect with the target volume requirement. Net CONE will be based on an estimate of the 'missing money' for a new Open Cycle Gas Turbine (OCGT) calculated as its levelised costs less its expected revenues from the energy and balancing markets. The Government has estimated net CONE as 29 £/kW in a central case. The Government is consulting on a price cap at 1.5 GW below the target volume. The price cap will either be a multiple of net-CONE (e.g. 1.5) or a higher administratively set price cap based on Combined Cycle Gas Turbine (CCGT) net CONE which the Government estimates would be 75 £/kW. Net CONE will also be used to set an offer cap in the auction for 'price takers' (existing plant not subject to major refurbishments), at 0.5 times net CONE or 0.7 times the previous year's auction clearing price, whichever is the lesser.

Capacity agreements

Successful existing capacity in the auction will be awarded a one-year capacity agreement at the clearing price, while existing plant that can demonstrate that they require major refurbishment may be eligible to access agreements with a term limit of up to three years in each auction round. New entrants will have a longer term agreement; the Government is proposing up to 10 years subject to the outcome of the Consultation, but has also raised the possibility of up to a 25 year agreement.

Capacity providers will be able to physically trade their obligations from a year ahead of the deliver year. The EMR Delivery Body will maintain a registry of capacity obligations and will provide its consent on any transaction. Participants are able to trade financially between themselves to manage the risks associated with non-delivery penalties.

Delivery of capacity

Capacity providers will have an obligation over the term of the capacity agreement to deliver a specified quantity of electricity during system stress periods. The obligation quantity will be "load following" so that capacity providers are only required to provide a proportion of their obligation quantity in relation to the anticipated demand at that point in time.

A system stress period will be notified by the SO as a "Capacity Market Warning" at least 4 hours in advance of any stress event. Capacity providers will need to be in a position to deliver energy on their obligation or face a penalty based on the value of lost load minus the prevailing "System Buy Price".

Penalty exposure would be capped annually at a percentage of their unit's clearing price multiplied by their MW of capacity agreements held, with the use of a "soft cap" to ensure that providers who have met their cap still have further incentives for delivery. The proposal is for the penalty cap to be at the portfolio level. Capacity providers who are able to over-deliver on their capacity agreement will be paid at the penalty rate. This creates the incentive on players who are able to exceed their load-following obligation to offer financial hedges for players whose plant may be temporarily unavailable.

The Delivery Body will also be able to spot-test plant where they have been unable to demonstrate their capacity volumes to the SO's satisfaction over the previous delivery year. Plant would be given an advanced warning of the test and would have to pay a penalty for failing to deliver.

Demand side arrangements

As previously mentioned, the Government proposes to run transitional arrangements of one year-ahead auctions for DSR, with the first auctions to be run in 2015 and 2016, therefore running ahead of the main Capacity Market. These will be for delivery of time-banded products upon a four hour dispatch instruction during the delivery year, with lower penalties than the enduring regime. The Government intends for these agreements to transition to a more standard load-following obligation over time, so that a proportion of capacity can be held back from the main auction in the future for DSR to make a reliable contribution to meeting total capacity requirements.

Small storage connected to the distribution network will be able to participate in the transitional arrangements for DSR, while large storage will only be able to participate in the main capacity auctions. The Government intends for permanent Electricity Demand Reduction (EDR) to participate in the Capacity Market, and intends to run a pilot auction for EDR in 2014-2015.

Supplier Levy

The costs of the Capacity Market will be recovered from a levy imposed on electricity consumers, via electricity suppliers.

2.2 Capacity Market Impact Assessments

During the development of the Capacity Market, DECC has performed Impact Assessments of the proposals. The most recent of these was published in October 2013, and prior to this, a July 2013 Impact Assessment was published alongside the Draft Delivery Plan.

DECC has assessed the costs and benefits of the CM using its Dynamic Dispatch Model (DDM). The DDM is DECC's in house medium to long term model of the GB electricity market. It models generation investment and retirement decisions and generation dispatch. The outputs are used to produce Cost Benefit Analyses of the impacts of policies, which feeds directly into Impact Assessments. It also produces outputs for capacity mix, generation, emissions, prices and security of supply, and generates values for consumer bill analysis.

2.2.1 DECC's analysis for the October Impact Assessment

In October 2013, DECC published an updated Capacity Market Impact Assessment[7]. As for previous Impact Assessments, DECC modelled a case with a Capacity Market (CM) and compared this to a case without a

[7] DECC, Capacity Market Impact Assessment October 2013, https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/252743/Capacity_Market_Impact_Assessment_Oct_2013.pdf

Capacity Market (No CM). Both cases are against a background of other EMR policies being in place, and use DECC's Updated Energy and Emissions Projection (UEP) Central case for commodity prices, carbon prices and electricity demand. The scenarios achieve decarbonisation of the electricity sector to approximately 100 gCO_2/kWh by 2030.

Modelling undertaken in the DDM suggests that the CM can deliver the target reliability standard of 3 hours LOLE and has the benefit of reducing the expected levels and hence costs of unserved energy, but increases the electricity generation costs and the system costs of transmission and balancing. The costs and benefits broadly offset each other and the estimate of the net benefit of the CM over the period 2013-2030 in Net Present Value terms is £450m (excluding the costs of implementing and administering the CM, which are estimated to reduce the net benefit to £180m).

The modelling also indicated that the CM increases costs for consumers of electricity, because the costs of capacity payments outweigh reductions in the costs of wholesale power. Overall, the CM is estimated to add £13 to the average annual domestic consumer bill from 2016 to 2030. The full Cost Benefit Analysis (CBA) results are presented and discussed in Section 4.

DECC's analysis for the July Impact Assessment

Previous to the October 2013, DECC published a July 2013 IA[8]. The differences in assumptions and model methodologies to the October IA are discussed in Appendix A.1.

The results show a similar change in net welfare to the October 2013 results. The resulting estimate of the net benefit of the CM over the period 2012-2030 in Net Present Value terms is around £400m (excluding the costs of implementing and administering the CM, which are estimated to reduce the net benefit to around £100m). Overall, the CM is estimated to add £17 to the average annual domestic consumer bill from 2016 to 2030. The full CBA results for the July IA are presented in Appendix A.2.

2.3 Scope of analysis

Redpoint Energy was commissioned by DECC to perform independent analysis of the costs and benefits of the GB Capacity Market, for comparison to the DECC DDM results.

Specifically, the analysis aimed to answer the following questions:

- What are the costs and benefits of the proposed Capacity Market in GB over the period from now until 2030?
- How do these costs and benefits differ between consumers and generation businesses?
- What differences are there between the assessed costs and benefits, compared to DECC's latest analysis?
- And to the extent possible, what important variables affecting the costs and benefits of the Capacity Market are not currently captured by DECC's modelling?

[8] DECC, Capacity Market Impact Assessment July 2013, https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/225981/emr_delivery_plan_ia.pdf

We were not asked to review the functionality of the DDM model in any detail, and our understanding of this functionality is based on our discussions with DECC's modelling team rather than a review of the model itself.

The analysis was conducted for CM and No CM cases using DECC assumptions from the July and October 2013 analysis. In the main body of the report we present the results based on DECC's October 2013 modelling assumptions. Analysis based on the July 2013modelling assumptions is included in Appendix A.

3 Approach

3.1 Modelling approach

Our analysis uses the Redpoint Investment Decision Model (IDM) which is described in detail in Appendix B. The IDM modelling suite produces outputs including capacity, generation, carbon dioxide emissions, wholesale power prices and capacity payments. The model also produces a full comparative Cost Benefit Analysis including allocation effects between consumers, producers and government.

Our model is based on similar principles to the DDM of modelling the investor decisions on generation investment and retirement based on imperfect expectations of future profitability. In Table 2 we compare the key features of the models.

Table 2 Comparison of DECC DDM and Redpoint IDM model features

Feature	DECC DDM	Redpoint IDM
Generation investment – investor foresight	5 years forward view of expected generation mix and demand	
Generation investment - Mothballing	Mothballing and de-mothballing of plant are exogenous assumptions	
Capacity Market – security standard	De-rated capacity margin target set based on a Loss Of Load Expectation (LOLE) of 3 hours per year, equivalent to a de-rated capacity margin of around 9-11% (after accounting for uncertainty in the future demand projections four years ahead)	Directly targets a 10% target de-rated capacity margin.
Capacity Market – generator bidding	Generator bids in the Capacity Market are based on the missing money required by each generator (the difference between expected revenues and costs)	Generator bids in the Capacity Market are based on the missing money required by each generator (the difference between expected revenues and costs) and a risk premium.
Capacity Market– DSR & Storage	Assumption of 1.7 GW of additional DSR by 2020. Model does not explicitly account for the transitional DSR and Storage auctions or the enduring year-ahead auctions	
Power market dispatch modelling	Models each characteristic day with three different wind levels, and takes a weighted average	Uses an implementation of National Grid's Electricity Scenario Illustrator (ELSI) model, which uses 102 periods in the year with a varying wind profile
Power market dispatch modelling - prices	Prices based on Short run Marginal Cost of marginal generator, and a calibrated uplift function.	Prices based on Short Run Marginal Cost of marginal generator, and a calibrated uplift function (Section 3.2)
Power market dispatch modelling - interconnectors	Interconnectors modelled with fixed exogenous flow assumptions	Interconnectors modelled as price responsive using simple representations of interconnected markets
Transmission investment and system costs	Additional costs provided by National Grid	Features available but not used in this project

Both the DECC DDM and the Redpoint IDM share a number of limitations:

- Generator bids in the Capacity Market are based on the missing money required by each generator, the difference between expected revenues and costs (plus a risk premium in the case of the

Redpoint modelling). Neither model considers bidding strategies that deviate from these principles, for example withholding capacity to increase prices. Hence, there is a risk that capacity payments could exceed those modelled, leading to higher consumer bills and increased generation sector profitability.

- The dispatch models are less detailed than the market leading electricity modelling solutions[9]. Market leading models typically take account of the full chronology of the year (8760 hours) and account for the technical parameters of generation plant such as Stable Export Limit, minimum on and off times, and ramp rates. However, the additional complexity of these models typically increases execution time which renders them less suitable for Investment Decision modelling which relies on evolving views of the future market prices. As a result, the dispatch models used may not capture the full volatility in power prices which may undervalue the wholesale power market revenues of peaking plant. This may cause these plant to appear less profitable in a No CM case, and in a CM case may lead to higher bids into the CM auction than would otherwise be the case.

3.2 Modelling assumptions

The key modelling assumptions have been aligned with those used in DECC's DDM. In this section we describe the assumptions used for the October IA, noting any differences in our assumptions from those used by DECC[10]. In Appendix A we note the differences in the July IA model runs.

Commodity prices, Carbon Floor Prices and peak and annual electricity demand are all aligned with DECC's UEP central case.

Low carbon capacity mix

Although the model is able to simulate investment decisions for low carbon generation under the Renewables Obligation and CfDs, the low carbon capacity mix was an exogenous assumption for this modelling exercise. The new build assumptions are aligned with the assumptions used by DECC and correspond to achieving renewable electricity generation targets by 2020 and reaching a carbon intensity of approximately 100gCO_2/kWh in 2030.

New technology costs

Cost parameters for new generation investments (capital costs, fixed and variable costs and efficiencies, hurdle rates) are aligned with DECC's assumptions. Consistent with DECC modelling in its central case, the Capacity Market is assumed to have no impact on hurdle rates for new plant.

Availability and de-rating factors

Values for the availability and de-rating factors of thermal plant are shown in Table 3. The de-rating factors are consistent with Ofgem's Capacity Assessment 2013[11] and represent an assumption for the statistically expected availability of that plant type at times of system stress. The availability assumptions used by DECC

[9] Such as for example PLEXOS for Power Systems, developed by Energy Exemplar, which Redpoint use for studies such as power market price forecasting, balancing and constraints modelling, and transmission flow modelling.

[10] We have aligned our assumptions to DECC assumptions, which may differ from our own in-house assumptions. We were not asked to comment on the validity of assumptions.

[11] https://www.ofgem.gov.uk/ofgem-publications/75232/electricity-capacity-assessment-report-2013.pdf

are taken from the PB Power review of generation costs for non-renewable technologies[12], and represent the expected average availability across the entire year, for new plant (but is applied to both new and existing plant in the DDM).

The periods in which thermal plant are not available are comprised of planned maintenance outages and unscheduled outages. Operators typically plan maintenance for summer periods, when demand is lower. Therefore technical unavailability in winter periods is expected to be mainly due to unscheduled outages.

Taking a specific plant type as an example, the assumed annual availability of 93% for a new CCGT implies an unscheduled outage rate of perhaps 3 to 4%. Based purely on forced outage rates, this would suggest that a higher de-rating factor of up to 96% would be appropriate for a new CCGT. This is significantly higher than the assumed de-rating factor of 85% for CCGTs. The values used in the Capacity Assessment are derived from analysis of data from the entire CCGT fleet. Lower reliability for the existing fleet may account for part of this difference, as could the scheduling of some maintenance in winter 'shoulder' months (October and March).

We recognise that the availability assumptions and de-rating factors have been derived in different contexts. In our view it is appropriate to adjust one or other number to ensure that annual availability is not higher than de-rating factor. Therefore in our modelling, we have capped the annual availability assumptions for thermal plant at the lower of the annual availability and the de-rating factor.

The effect of this is to produce annual availabilities which are lower than the DECC assumptions. The reduced availability has the effect of increasing wholesale market prices, for the same generation mix. This could lead to additional new entry, absent a Capacity Market. With a Capacity Market, the level of capacity will be unchanged but Capacity Market clearing prices would be lower.

Had we used DECC's assumptions as provided, wholesale prices in the Redpoint IDM would be lower. Although the newest CCGTs would run more often they would receive lower margins from the wholesale market overall.

[12] All DECC information on generation cost assumptions can be found at: https://www.gov.uk/government/collections/energy-generation-cost-projections

Table 3 De-rating factors and availability assumptions[13]

	De-rating factor	DECC availability assumptions	Derived availability assumptions for the modelling
CHP	85%	93%	85%
Oil	82%	93%	82%
Hydro[14]	84%	34%	34%
Pumped Storage	100%	96%	96%
Nuclear	90%	91%	90%
CCGT	85%	93%	85%
OCGT	92%	95%	92%
Coal	88%	93%	88%
Coal + CCS	88%	96%	88%
CCGT + CCS	85%	93%	85%

The assumed contribution of interconnectors changes across the modelling period. Prior to 2020, interconnectors are assumed to make no net contribution to security of supply (i.e. a de-rating factor of 0%). Interconnector de-rating factors then increase to 57% between 2020 and 2025[15].

In the Redpoint modelling, interconnectors provide a source of flexibility to import power when GB is short, and export power at times of high renewable generation. Interconnectors therefore have the effect of reducing the variation of power prices across the year. This is independent of the de-rating factor. In the DECC modelling, the flow of power on interconnectors is an exogenous assumption.

In the near term, since the de-rated margin (shown in Figure 1, Section 4.1) is presented assuming that interconnectors are not contributing to available peak capacity, the margins appear lower than they are in the dispatch model. Normally very low margins would lead to high wholesale electricity prices, but allowing interconnectors to import in our model lessens this effect.

Costs and revenues for new and existing thermal plant

Table 4 shows the fixed annual costs and the annuitised capital costs that make up the total annual non-variable costs of selected large scale generation technologies. The value of 47 £/kW for New OCGT is

[13] De-rating factors are DECC assumptions based on Ofgem Electricity Capacity Assessment Report 2013. Annual availabilities are DECC assumptions. All DECC information on generation cost assumptions can be found at: https://www.gov.uk/government/collections/energy-generation-cost-projections

[14] 34% availability represents the average output across the year. 84% is the assumed availability of hydro at times of system stress (from Ofgem's Electricity Capacity Assessment Report 2013)

[15] DECC assumption based on Pöyry: Impact of EMR on Interconnection, https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/252744/Poyry_Report_on_Impact_of_CM_on_Interconnection.pdf

equivalent to the gross Cost of New Entry (CONE) as defined by DECC in the Capacity Market proposals currently being consulted on.

Table 4 Fixed and annuitised capital costs for new and existing plant (2020)[16]

Technology	Annual fixed cost £/kW/yr	Annuitised capital cost £/kW/yr	Total annual cost £/kW/yr
New CCGT	31	56	88
New OCGT	18	29	47
Existing CCGT (range)	21-44	-	21 - 44
Existing coal (range)	36 - 54	-	36 - 54

The values above represent the underlying fixed costs of generation. To build up the revenue required from the wholesale market and from the Capacity Market, we include assumptions on revenues from services provided to the System Operator (ancillary services) and a risk premium due to Capacity Market penalties (where relevant). The values are shown in Table 5.

Table 5 Key cost data and ancillary services revenues for new and existing plant (2020)[17]

Technology	Total annual cost £/kW/yr	Ancillary services revenue £/kW/yr	Risk premium £/kW/yr	Total missing money before wholesale and CM revenues £/kW/yr
New CCGT	88	10	5	83
New OCGT	47	15	5	37
Existing CCGT (range)	21 – 44	10	5	16 - 39
Existing coal (range)	36 – 54	-	5	41 – 59

Generators may provide ancillary services either through the Balancing Mechanism, where their bids and offers may be accepted by the System Operator to resolve energy imbalance, create reserve or resolve

[16]Source: All DECC information on generation cost assumptions can be found at: https://www.gov.uk/government/collections/energy-generation-cost-projections

Values for existing CCGTs and coal plant are adjusted by TNUoS charges and (for CCGTs only) gas exit charges. Annuitised cost calculated by Redpoint based on DECC capital cost assumptions and hurdle rates.

[17]Ancillary services assumptions provided by DECC. Risk premium is a Redpoint assumption.

constraints, or through contracted services to the SO[18]. In reality, ancillary services revenues (and the margin made on these) will vary significantly based on generator type and location.

The assumed ancillary services revenues reduce the value which generators require from the wholesale market and from capacity payments. Assumed ancillary services revenues have been provided by DECC by plant type and are higher for CCGTs and OCGTs than coal.

Under the Capacity Market, generators are exposed to penalty payments if they are not available at times of system stress. DECC is currently consulting on the final parameters for the penalty regime which include a cap of between 101-150% of the generator's annual capacity payment, applied at a portfolio level.

We have applied a risk premium to all generators' Capacity Market bids, which is derived from assumptions on the likelihood of not being available at times of system stress, and the size of penalty payments[19]. The derived risk premium of 5 £/kW is added on to generator bids which will increase the capacity auction clearing price by £5/kW, all other things being equal. The ability to receive payments for over delivery during stress periods may in future stimulate trading of financial hedges that could offset the risk of under-delivery and reduce risk premia, however it is not yet clear if these financial hedges will be developed and form a secondary market. In the DECC modelling, no explicit non-delivery risk premium is applied.

To derive final Capacity Market bids, we adjust for expected wholesale electricity market revenues and for the de-rating factor. In the Redpoint modelling, new CCGTs typically require a smaller CM payment than new OCGTs. The majority of existing CCGTs and coal plant require smaller payments than new plant. However, the least efficient plant which rarely run may require a capacity payment which is larger than that for new plant.

In the DECC modelling, new CCGTs typically make lower gross margins from the wholesale market (see below) and require higher capacity payments in order to break even.

Uplift / scarcity value

Within the Redpoint IDM, wholesale market electricity prices are a function of two factors:

- The short run marginal cost of the marginal generating plant in each period; plus
- A calibrated 'uplift' function[20], which adds a margin to the system short run marginal cost depending on the tightness (capacity margin) in each period. This includes recovery of start costs as well as the ability to increase prices in tight periods.

We assume that Ofgem's proposed cash-out reforms[21] are implemented, allowing prices to rise to £6,000/MWh at times of lost load. Hence, prices are able to rise significantly above the prices that have been observed historically.

[18] Examples of contracted services are Frequency Response (to manage very short term deviations in the frequency of the transmission system) and Short Term Operating Reserve (STOR)(capacity that National Grid retains on stand-by that can be called on to generate export within four hours of instruction, with a focus on <20min).

[19] The risk premium model uses a distribution of the coincidence of system stress periods (using LOLE of 3 hours) with an outage for an individual plant. The model uses the 90% confidence interval of this distribution, multiple by the expected penalty price. The expected penalty price is based on a Value of Lost Load of £17,000/MWh with a multiplier of 0.4.

[20] The uplift function within the model was calibrated using 2009/2010 data.

[21] https://www.ofgem.gov.uk/ofgem-publications/82294/ebscrdraftdecision.pdf

Our understanding of the DECC DDM is that it follows a similar principle of applying an uplift over SRMC. However the impact of uplift on prices appears to be lower, and uplift, and therefore prices in general, is less sensitive to the capacity margin than the Redpoint modelling.

In the DECC modelling prices do not react as strongly to tighter margins and therefore the profitability of generators in the wholesale power market does not increase with tighter margins. There remains a larger portion of 'missing money' which means that generators do not recover as much of their costs. In the DECC modelling, generator bids into the Capacity Market are higher, with the increase being particularly significant for those generators with higher load factors that make significantly higher margins in the wholesale market in the Redpoint modelling. For example, CCGT bids in the DECC modelling will increase more than OCGT bids relative to the Redpoint modelling, leading to a different ordering of plant in the capacity auction.

We note that the evolution of pricing behaviour, particularly in extremely tight periods which have only rarely been observed, is highly uncertain. The impact of a Capacity Market on wholesale market pricing behaviour is also an unknown. Pricing behaviour may remain unchanged, or alternatively generators may offer closer to Short Run Marginal Cost, leading to a reduction in uplift and lower average wholesale prices, and therefore correspondingly higher bids in the CM auction.

4 Results

In this section we describe and compare the key results from the DECC and Redpoint modelling, using the October Impact Assessment assumptions[22]. We show the results of a No CM and CM case for both the DECC and Redpoint modelling.

The results covered in this section are:

- De-rated capacity margins
- New build and retirements of plant eligible for the Capacity Market
- Wholesale power prices
- Capacity Market clearing prices
- Cost Benefit Analysis (the costs and benefits of the CM case relative to the No CM case)
- Impact on domestic consumer bills

4.1 De-rated capacity margin

Figure 1 shows the de-rated capacity margins for the four cases. The margins are similar across all runs up to 2016 because in the October analysis the capacity assumptions have been aligned with the Ofgem Capacity Assessment 2013.

Redpoint modelling

In the Redpoint modelling, after 2016 closures of unprofitable CCGT and coal plant reduce margins. The Capacity Market stabilises capacity margins from 2019, whereas in the No CM run margins are more variable. The large drop in de-rated capacity margins in the No CM cases coincide with the LCPD and IED related closures in the run up to 2016 and in 2023. In the early 2020s, the de-rated capacity margin spikes as investors commission new plant in anticipation of future closures[23]. This is a similar effect to the wave of new CCGT investment seen in recent years in anticipation of LCPD related closures. This effect is supplemented by the assumed increase in the contribution of interconnectors to security of supply over this period, which increases the de-rated margin without any changes in the underlying plant mix. The increase in the contribution from interconnectors leads to an increase in the reported margin of 6%.

DECC modelling

In the DECC modelling, the Capacity Market encourages some plant to stay open over the period 2016 to 2019, which closes in the DECC No CM run. After 2019, the de-rated margins in the CM case are in a range between 7% and 10%. In the No CM case, the smoother trajectory of de-rated capacity margins in the DECC

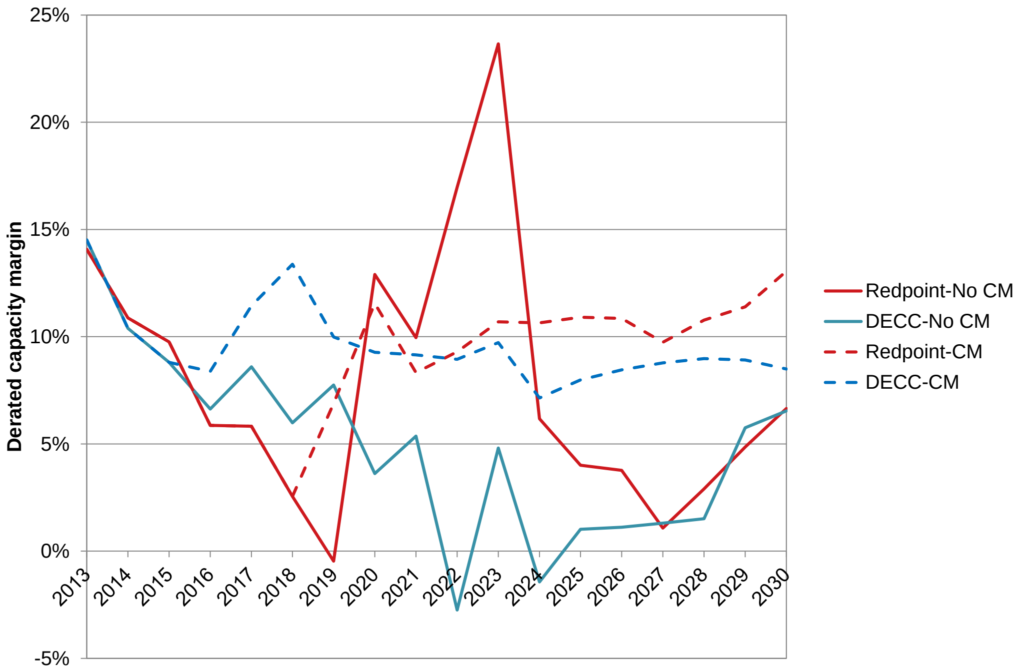
[22] In Appendix B we show the same set of results for model runs using the July Impact Assessment assumptions.

[23] The logic of investment decision making in the model does not necessarily time investments perfectly, as there is uncertainty about future retirements and other new build when decisions are made.

modelling compared to the Redpoint equivalent No CM case suggests a closer match between investment and anticipated closures. For example, the expectation of tight capacity margins following the IED related closures in 2023 is driving significant new investment.

The de-rated capacity margin is lower on average in the DECC No CM case due to less new plant build. The differences reflect the fact that prices, and investors' expectation of prices, are much more sensitive to tighter capacity margins in the Redpoint modelling compared to the DECC modelling, which means that margins in the DECC analysis have to fall lower to incentivise new build.

Figure 1 De-rated capacity margin[24]



4.2 New build and retirements of plant eligible for the Capacity Market

Figure 2 shows the total new build of plant eligible for Capacity Payments in the CM case, comparing the Redpoint and DECC results. The overall build of new capacity is higher in the Redpoint CM case.

New CCGTs

The development of new CCGTs is significantly higher in the Redpoint modelling than in the DECC modelling, with 32 GW deployed by 2030. This is a result of higher expected profitability in the energy market for new CCGTs, which incentivises new build through lower bids in the Capacity Market auctions. The amount of missing money is less for CCGTs than in the equivalent DECC case. This results in new CCGTs

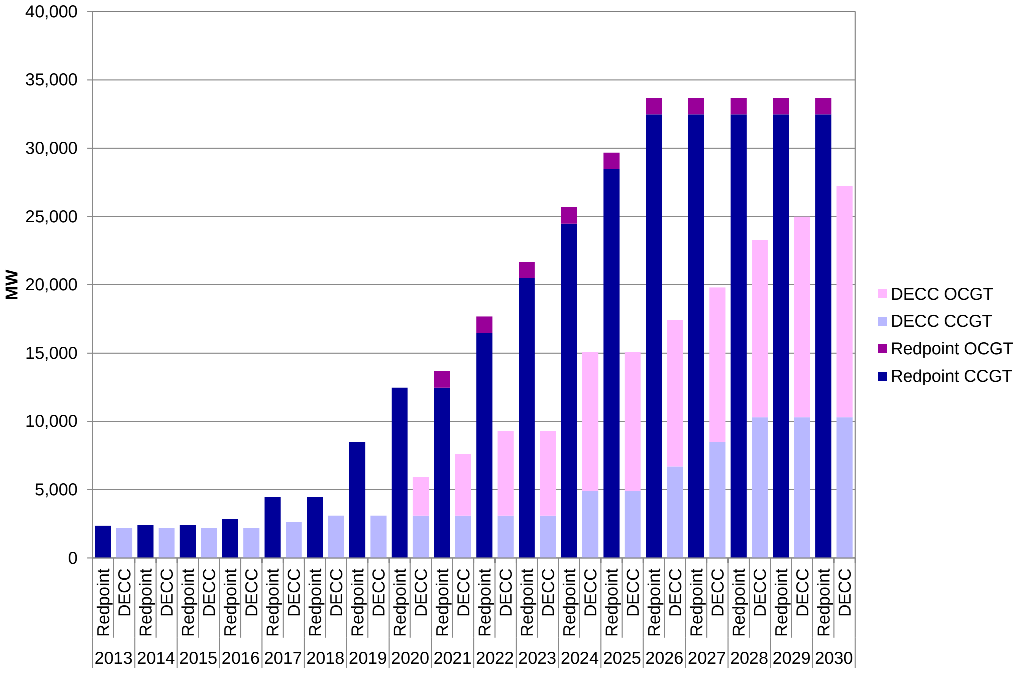
[24] Note that this assumes that the contribution of interconnectors to the derated margin increases from 0% to 57% over the period 2020 to 2025.

being competitive in the Capacity Market with existing plant and new OCGTs (due to higher load factors), which is not the case in the DECC modelling.

New OCGTs

In the DDM modelling, new OCGTs are more competitive than new CCGTs and are a deployed at a large scale from 2019, whereas in the Redpoint CM case only 1.2 GW of new OCGT is constructed by 2030. In the Redpoint CM case, new OCGT clears in the auction in 2024 because the maximum build of CCGTs has been reached[25].

Figure 2 Total new build for thermal capacity (CM cases) [26]



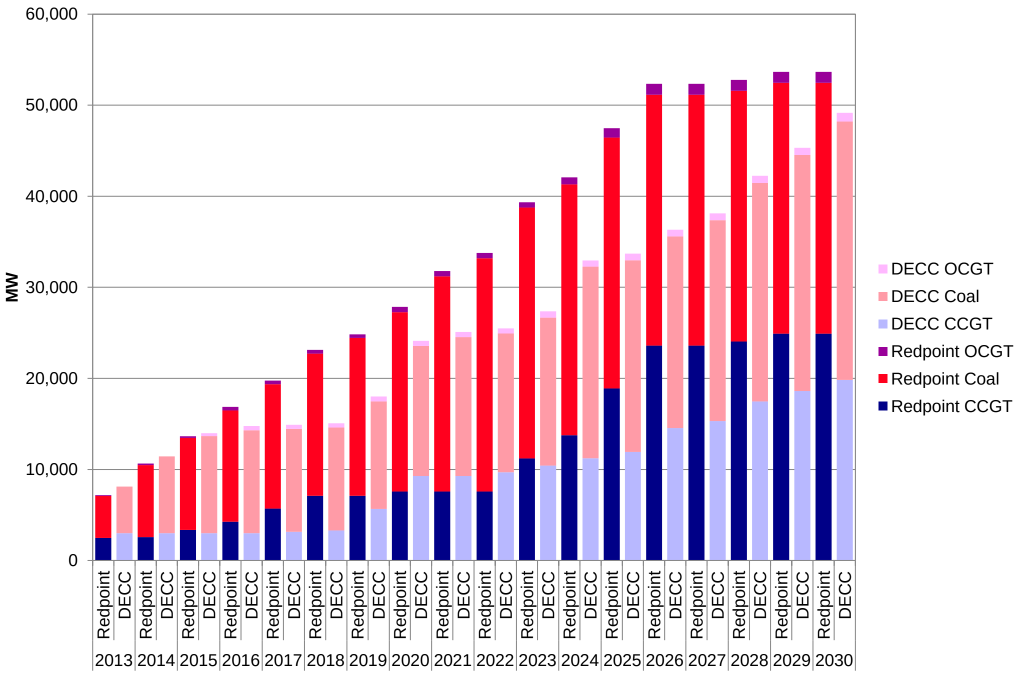
The Redpoint CM case also observes more retirements in total relative to the DECC CM case, with first coal and then existing CCGTs being replaced by new CCGTs. Retirement assumptions are aligned until 2016. After this point, the Redpoint CM case brings forward coal retirements. This is because these plant are less competitive with CCGTs given their higher fixed costs and assumed lower ancillary services revenues. Between 2022 and 2026, existing CCGTs retire rapidly because the required thermal capacity is reducing over this period for three reasons. First, new nuclear capacity is coming online; second, new DSR capacity of 1.7 GW is assumed to become available by 2025; and third, the contribution of interconnectors to security of supply is assumed to be increasing (and the volume requirement in the capacity auctions reduces correspondingly).

[25] In the Redpoint No CM run no new OCGTs are built. In the No CM case, the lower capital cost and fixed costs of new OCGTs compared to CCGTs are not sufficient to outweigh the impact of lower efficiency (and hence lower load factor and lower energy market revenues).

[26] Includes CCGTs returning from mothball

The DECC CM case tends to keep existing plant on because the capacity payment required by new CCGTs is higher. Therefore existing plant still receive sufficient remuneration via the Capacity Market to stay open. The rate of retirement is steadier throughout the modelling period.

Figure 3 Total retirement stack for thermal capacity (CM cases)



4.3 Wholesale power prices

The wholesale power prices in each of the four cases are shown in Figure 4. In the near term, the Redpoint model wholesale prices are £3/MWh higher than in the DECC modelling, which appears to be due to differences in the assumptions for the availability of new and existing plant (Section 3.2).

In the Redpoint modelling, the annual availability of thermal plant is lower which means that the marginal plant is likely to have a higher SRMC, which increase wholesale prices.

We have not aligned the assumed thermal efficiency and variable costs of existing plant between the two models. Lower efficiencies on average in the Redpoint modelling will increase the Redpoint prices.

Redpoint modelling

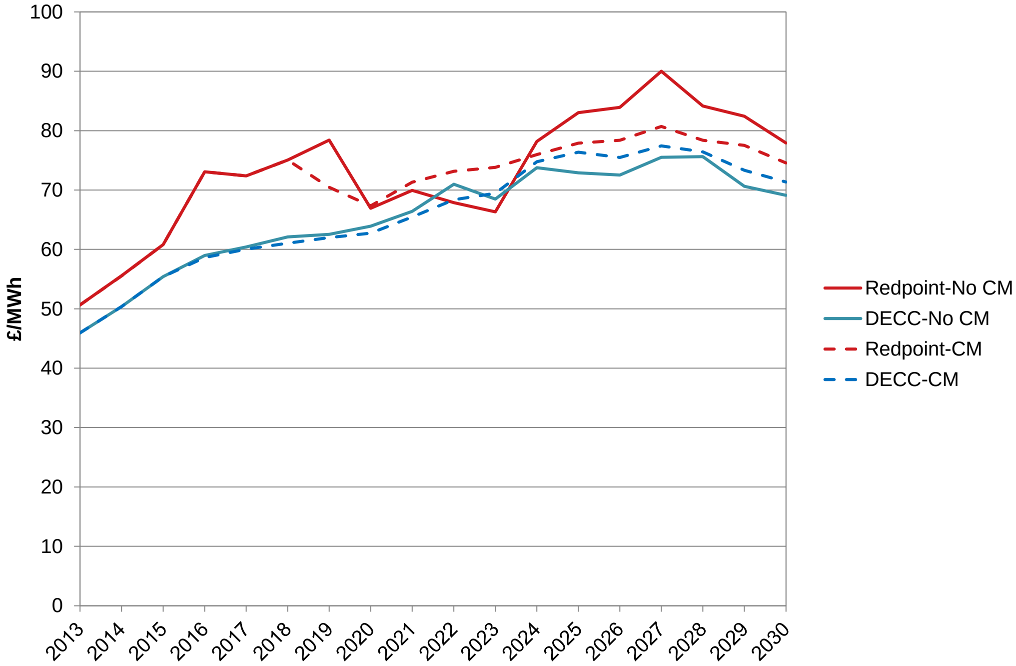
As de-rated capacity margins begin to tighten from 2016 onwards, wholesale prices in the Redpoint modelling increase. This is due to the parameters of the calibrated uplift function, which increases prices when margins are tight (Section 3.2).

In the Redpoint modelling, wholesale prices are typically higher in the No CM case. However, this is reversed between 2020 and 2023 when the No CM case has higher de-rated capacity margins than the CM case.

DECC modelling

In the DECC modelling, wholesale power prices do not respond as strongly to tighter capacity margins and are much closer between the No CM and CM cases throughout the modelling period. As discussed below, this could understate the benefit of a CM (to consumers) of lower and less volatile wholesale prices. After 2023, wholesale prices are actually higher in the CM case than the No CM case, despite the significantly higher de-rated capacity margins, due to the less efficient plant mix, consisting of a large proportion of new OCGTs which have high SRMCs relative to CCGTs.

Figure 4 Time-weighted annual average wholesale power prices (real 2012)

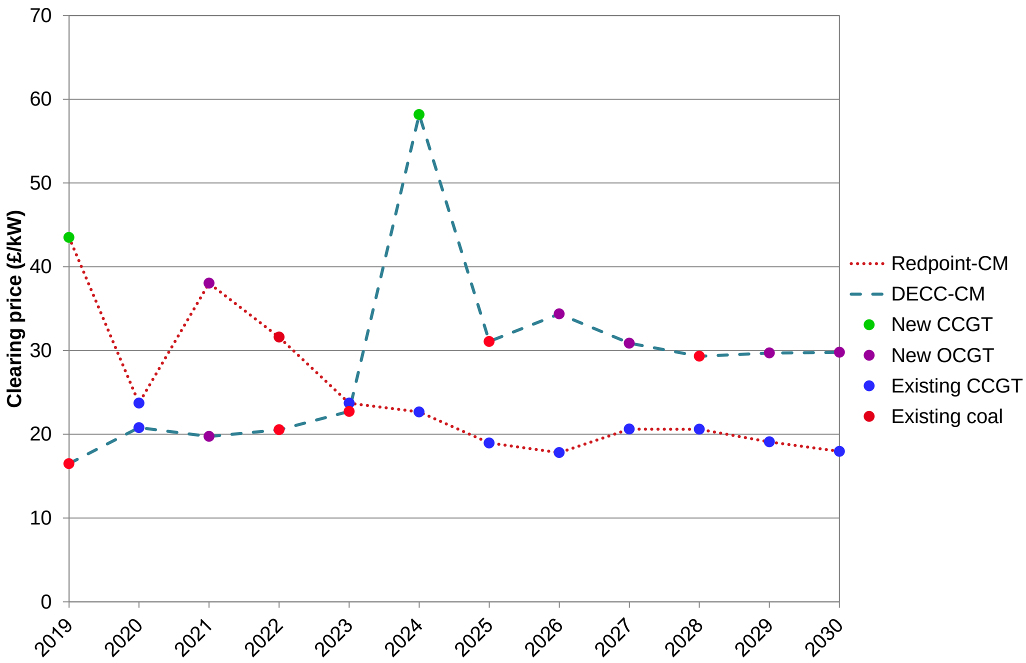


4.4 Capacity Market clearing prices

CM clearing prices (Figure 5) are set mainly by existing CCGTs in the Redpoint modelling. The highest price in the Redpoint CM case is set in 2019, close to the assumed price cap. Clearing prices are lower after this point, set typically by existing CCGTs. The capacity payment required by new CCGTs is lower than that required by the least profitable existing CCGTs because new CCGTs make significant margins in the wholesale market (after accounting for their fuel, carbon and variable costs) given their higher efficiencies (and therefore higher load factors).

The clearing prices in the DECC modelling are lower until 2024 and are set mainly by existing plant, with new OCGTs having a lower bid price and clearing in the auction. In 2024, new CCGT is required to meet the security standard, and hence the clearing price reaches £58/kW. After this point clearing prices are set by a mixture of new OCGTs and existing plant.

Figure 5 Capacity Market clearing prices (real 2012)



4.5 Cost Benefit Analysis

The costs and benefits of the CM are measured against the No CM case as the counterfactual. The costs and benefits are calculated annually and as a net present value (NPV) for the period 2013-2030 using the Green Book real discount rate of 3.5% and presented in real 2012 terms. The values are also presented in two periods: 2013-2020 and 2021-2030.

- **Carbon costs.** The change in value of carbon dioxide emissions as measured using the cost of EU Allowances (EUAs). A positive number represents a decrease in carbon dioxide emissions (i.e., a saving in EU ETS allowance costs to the GB power sector). For the avoidance of doubt, the costs of the Carbon Price Support are not included as these are a transfer to the Exchequer.
- **Generation Costs.** The change in the costs of generating electricity, including changes in fuel costs and variable and fixed operating costs. It excludes changes in the costs of carbon which are captured above, and capital costs which are captured below. A negative number represents an increase in generation costs relative to the counterfactual.
- **Capital costs.** The change in capital expenditure in new plant, annuitised across the economic life of the individual plant. A negative number represents an increase in capital costs.
- **Unserved energy.** The change in the cost of expected energy unserved, which is valued at an average £17,000/MWh[27]. A positive number implies a decrease in the cost of unserved energy and an improvement in security of supply.

[27] The Value of Lost Load (assumed to be £17,000/MWh) is distinct from the assumed maximum wholesale market price (£10,000/MWh in July modelling, £6,000/MWh in October results).

- **Net welfare.** The change in welfare to the economy as a whole which is equivalent to the sum of the change in carbon costs, generation costs, capital costs, unserved energy and demand side response. A negative number represents a loss in net welfare to the economy.
- **Consumer surplus**. The change in welfare to consumers, which is a combination of the change in wholesale electricity costs, change in the low carbon payments, and the change in capacity payments (where these apply). A negative number represents a reduction in consumer surplus or an increase in the costs to consumers.
- **Producer surplus.** The change in the profitability of the generation sector measured as the change in the difference between revenues (electricity sales, low carbon support and Capacity Payments) and producer costs. A positive number represents an increase in the producer surplus.
- **Environmental tax.** The change in the value of environmental tax receipts (Carbon Price Floor) by the Exchequer.

Redpoint modelling

The Cost Benefit Analysis for the Redpoint modelling (Table 6) shows a small net welfare reduction associated with the CM. Savings in unserved energy (due to higher capacity margins) and generation costs (due to a more efficient generation fleet) are outweighed by increases in capital costs for new CCGTs. By contrast, using the July assumptions the Redpoint modelling showed a small net welfare benefit from the CM (Appendix A). This difference can be attributed to the lower assumed contribution to security of supply from interconnectors in the July assumptions, increasing the value of additional generation capacity in the GB market. The difference in these two sets of results serves a useful purpose in demonstrating that the economic case for a CM is very dependent on how much interconnectors can be relied on to import at times of system stress.

In the Redpoint analysis, consumers are worse off in the CM case (also the case using the July assumptions), because the additional cost of capacity payments (£1-2bn annually) is not offset by the savings in costs of unserved energy and the reduction in wholesale electricity prices[28]. The increase in the average annual domestic consumer bill over the period 2016-2030 due to the CM is approximately £5. Conversely, producers receive a net benefit from the introduction of the CM.

[28] We note that there is more uncertainty associated with estimate of unserved energy and wholesale price due to their dependence on within-year uncertainty in variables such as the level of demand and forced outages.

Table 6 Redpoint Cost Benefit Analysis

Change in welfare (£m, 2012 real)		NPV (2013-2030)	NPV (2013-2020)	NPV (2021-2030)
Net Welfare	Carbon costs	-160	20	-180
	Generation costs	680	-10	700
	Capital costs	-1530	-180	-1360
	Unserved energy	820	410	410
	Change in Net Welfare	**-190**	**240**	**-430**
Distributional analysis				
Consumer Surplus	Wholesale price	7160	2140	5020
	Low carbon payments	-2220	-190	-2040
	Capacity payments	-10450	-2690	-7760
	Unserved energy	820	410	400
	Change in Consumer Surplus	**-4690**	**-320**	**-4370**
Producer Surplus	Wholesale price	-7160	-2140	-5020
	Low carbon payments	2220	190	2040
	Capacity payments	10450	2690	7760
	Producer costs	-930	-130	-800
	Change in Producer Surplus	**4580**	**600**	**3980**
Environmental Tax	Change in Environmental tax revenue	**-80**	**-40**	**-40**

DECC modelling

The DECC CBA values have been set out in a similar format (Table 7). The DECC results include an additional term for system costs (transmission and system balancing costs). The impact of the CM on system costs was out of scope for our analysis and we have not investigated the drivers of the increase in system costs in the DECC CM case. The Interconnector term in the DECC results is amalgamated into generation costs in our analysis.

In the DECC modelling, the CM delivers a small increase in net welfare. The unserved energy saving is larger than in the Redpoint modelling. There is also a saving in capital costs, rather than an additional cost as seen in the Redpoint modelling, since the DECC modelling suggests greater extension of existing plant, and building of cheaper OCGTs under a CM.

In the DECC modelling, consumers are worse off in a CM world, by a larger amount than in the Redpoint modelling. This is because, as highlighted above, wholesale prices in the DECC modelling do not react as strongly to capacity margin and therefore the benefits of having a higher capacity margin on average are not as large. In fact, wholesale costs to consumers are actually higher on average with a CM over the period 2021- 2030. Overall, the increase in the average annual domestic consume bill over the period 2016-2030 due to the CM is £13[29]. Producers are also considerably better off under the CM in the DECC modelling.

[29] Bill impacts include the components of consumer bills that vary between model runs (costs of wholesale power and capacity payments). Bill impacts do not include the savings to consumers of reduced unserved energy.

Table 7 DECC DDM Cost Benefit Analysis

Change in welfare (£m, 2012 real)		NPV (2013-2030)	NPV (2013-2020)	NPV (2021-2030)
Net Welfare	Carbon costs	-850	-20	-830
	Generation costs	-180	-110	-70
	Capital costs	1,420	70	1,350
	System costs	-1,180	-450	-730
	Unserved energy	1,290	60	1,230
	Interconnectors	-50	10	-60
	Change in Net Welfare	**450**	**-450**	**900**
Distributional analysis				
Consumer Surplus	Wholesale price	-1,080	980	-2,060
	Low carbon payments	1,170	-90	1,260
	Capacity payments	-10,590	-1,420	-9,170
	System costs	-1,180	-450	-730
	Unserved energy	1,290	60	1,230
	Change in Consumer Surplus	**-10,390**	**-920**	**-9,470**
Producer Surplus	Wholesale price	1,030	-970	2,000
	Low carbon support	-1,170	90	-1,260
	Capacity payments	10,590	1,420	9,170
	Producer costs	-130	-200	70
	Change in Producer Surplus	**10,320**	**340**	**9,980**
Environmental Tax	Change in Environmental Tax Revenue	**520**	**130**	**390**

5 Conclusions

In this section we present our overall conclusions on the comparisons between the DECC and Redpoint CM modelling based on DECC's October 2013 assumptions. Table 8 is a summary of the net welfare and consumer bill impact values from the two sets of analysis.

Table 8 Summary CBA and bill impact results (real 2012)

	DECC	Redpoint
Net welfare NPV (NPV 2013-2030, £m)	450	-190
Annual average domestic consumer bill impact (2016-2030, £)	13	5

Redpoint modelling

In the Redpoint modelling, the presence of a Capacity Market stabilises de-rated capacity margins, (which are volatile in the No CM case) and reduces the costs of unserved energy. The effect of the CM is to smooth out new build prior to 2024 and deliver more capacity in the longer term. Most of the new build is CCGT. Net welfare reduces by £190m because savings in unserved energy are outweighed by increases in capital costs from building more CCGTs overall.

The average annual domestic consumer bill over the period 2016-2030 increases by £5 (this does not include the benefit of reduced unserved energy). Consumers as a whole (including both domestic and business consumers) make capacity payments of between £1-2bn per year. This cost is partially offset by savings in the costs of wholesale electricity, which occur in all years except 2020-2023 (when capacity margins are higher, and therefore wholesale prices lower, in the No CM case relative to the CM case).

DECC modelling

In the DECC modelling, the existence of a Capacity Market increases de-rated capacity margins and reduces the costs of unserved energy, by bringing forward the build of new capacity, and keeping existing capacity on the system. The savings in costs of unserved energy and in capital costs in the DECC CM case compared to the DECC No CM case are offset by increases in generation costs and system costs. Overall, this is a net welfare benefit of £450m.

In the DECC modelling, the average annual domestic consumer bill in the period 2016-2030 increases by £13. There is little reduction in wholesale electricity costs to offset the cost of the Capacity Payments. In fact after 2024, wholesale prices are actually higher in the CM case.

The modelling of the wholesale power market is the major difference between the DECC DDM and Redpoint IDM results

Given the similarity in the modelling methodology and the aligned set of assumptions, a high level of similarity between the Redpoint and DECC results might be expected. The major areas of differences can be traced back to the different responsiveness of wholesale prices to tight capacity margins, which results in different outcomes in terms of consumer bill impacts and in generation mix. In particular, the cost to consumers is very sensitive to this modelling parameter. In both sets of analysis, the CM imposes additional costs on consumers. The DECC DDM outputs could be viewed as the more conservative approach to evaluating a CM and may overstate the costs to consumers, although we note that the evolution of pricing behaviour, particularly in extremely tight periods which have only rarely been observed, is highly uncertain.

We recommend that sensitivity analysis is performed to explore the uncertainty around wholesale prices when margins are tight. We also recommend ongoing back-testing, including comparison of DDM wholesale price outputs to outturn data, to monitor changes in mark-ups as the wholesale market tightens as expected over the next few years.

There are uncertainties regarding the costs and benefit of the Capacity Market that are not captured in the modelling

The results indicate that the net welfare impact of the CM is small, but the CM imposes additional costs on consumers. These conclusions are subject to a number of uncertainties which we explore below.

The overall welfare benefit is very dependent on the Value of Lost Load, which is a highly uncertain parameter which will vary by consumer type and by the frequency and duration of lost load. The net cost of the CM is lower if consumers value the additional security of supply more highly, and vice versa. The level of outturn margin without a CM is highly uncertain and the scenarios modelled show one possible outcome. If future de-rated margins were in fact more (or less) volatile then the benefits of a CM would be higher (lower).

The assumed de-rated factors directly define the amount of capacity procured to deliver a certain reliability standard. As these factors are input assumptions, neither model demonstrates the risk of getting these wrong, which could lead to over- or under-procurement of capacity. In our view there is a risk that factors estimated from historic commercial availability data covering winter peak periods may underestimate the true technical availability (particularly in a CM world with stronger incentives on generators to ensure they are available when required). These factors are difficult to estimate and there is a risk that a bias towards a conservative view could deliver a higher reliability standard than intended, and thus increase the costs of the CM.

The results are sensitive to the assumed contribution of interconnectors to security of supply. Using the July assumptions the Redpoint modelling showed a small net welfare benefit from the CM (Appendix A). This difference can be attributed to the lower assumed contribution to security of supply from interconnectors in the July assumptions, increasing the value of additional generation capacity in the GB market. The difference in these two sets of results serves a useful purpose in demonstrating that the economic case for a CM is very dependent on how much interconnectors can be relied on to import at times of system stress.

The potential for additional contributions from DSR (including small embedded generators) and storage has not been explored in this study.

The CM results from both sets of modelling show fairly stable de-rated capacity margins, close to the target margin in each case. However, there are risks to the capacity margin with a CM in place, that are not necessarily captured in the modelling, including the risk that demand growth is higher than expected in the demand forecast fed into the capacity requirement calculation. The margin also does not show that there are significant level of retirements and commission of new build in the same year (for example with the IED closures at the end of 2023). Any delays to the commissioning of capacity could lead to more variation in outturn margins from those seen from either model for a CM case.

Both models use a 'missing money' approach to modelling generator bids into the CM. We have not modelled different bidding strategies of participants in the CM which could increase the costs of the CM.

We have not performed sensitivity analysis on these results to consider the impact of different demand scenarios, low carbon build, commodity prices, or capital costs.

A July Impact Assessment

A.1 Assumptions for July Impact Assessment

DECC made a set of changes in the analysis for the October IA, compared to the July IA. Table 9 describes these changes and how these have been incorporated in the Redpoint IDM.

Table 9 Assumption differences between July IA and October IA

Change in October IA	Main impact in DDM	Included in Redpoint model
1.7 GW of additional Demand Side Response, available in CM run between 2020 and 2025[30].	Reduction in amount of gas plant required before 2030 to maintain LOLE standard.	Yes
Updated to UEP2013 demand.	Demand is generally higher, increasing peak demand and reducing capacity margin.	Yes
Updated to UEP2013 CHP capacity.	Less gas CHP capacity, reducing margins, particularly in the short term.	Yes
Cost of OCGTs increases as more are built. Build limits are increased. PB Power high capital cost estimates used to set upward sloping supply curve.	Auction clears more often on new OCGT, with a higher clearing price than previously.	No impact as less OCGT built in Redpoint modelling
New interconnection capacity increased to 3GW (Belgium, Norway and France). Interconnector de-ratings (previously 0% throughout) increase to 57% between 2020 and 2025[31].	Reduction in amount of domestic generation capacity required to maintain capacity margin.	Yes
Aligned capacity to Ofgem's Capacity Assessment until 2016.	Maintains margins in the short term.	Yes
No economic retirements before 2016 in either scenario. This ensures that up to 2016 the supply side matches Ofgem's assumptions.	Reduces fall in de-rated capacity margin in 2015-2016.	Yes

[30] DECC assumption based on empirical evidence from PJM. https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/252743/Capacity_Market_Impact_Assessment_Oct_2013.pdf, page 18

[31] DECC assumption based on Pöyry: Impact of EMR on Interconnection, https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/252744/Poyry_Report_on_Impact_of_CM_on_Interconnection.pdf

Change in October IA	Main impact in DDM	Included in Redpoint model
No OCGTs built before 2020. No large OCGTs (on which costs are based) currently in planning.	Other sources of capacity required to meet margin target.	Yes
Overall endogenous retirement: threshold increased limit from 2 GW to 10 GW.	Decreases de-rated capacity margins in the No CM scenario.	Redpoint endogenous retirement limits unchanged
July IA: a target 10% de-rated capacity margin with no demand curve. October IA a de-rated capacity margin target set based on a Loss Of Load Expectation (LOLE) of 3 hours per year, equivalent to a de-rated capacity margin of around 9-11% (after accounting for uncertainty in the future demand projections four years ahead).		In the Redpoint modelling we used a demand curve with a 10% target de-rated capacity margin for both the July and October modelling
Change to VoLL: Prices rise to £6,000/MWh rather than £10,000/MWh in the event of lost load. Consistent with Ofgem's draft decision on cash-out reform.	Small impact.	No change required

A.2 Results using July Impact Assessment assumptions

A.2.1 De-rated capacity margin

Figure 6 shows the de-rated capacity margins for the CM and No CM cases (DECC and Redpoint modelling).

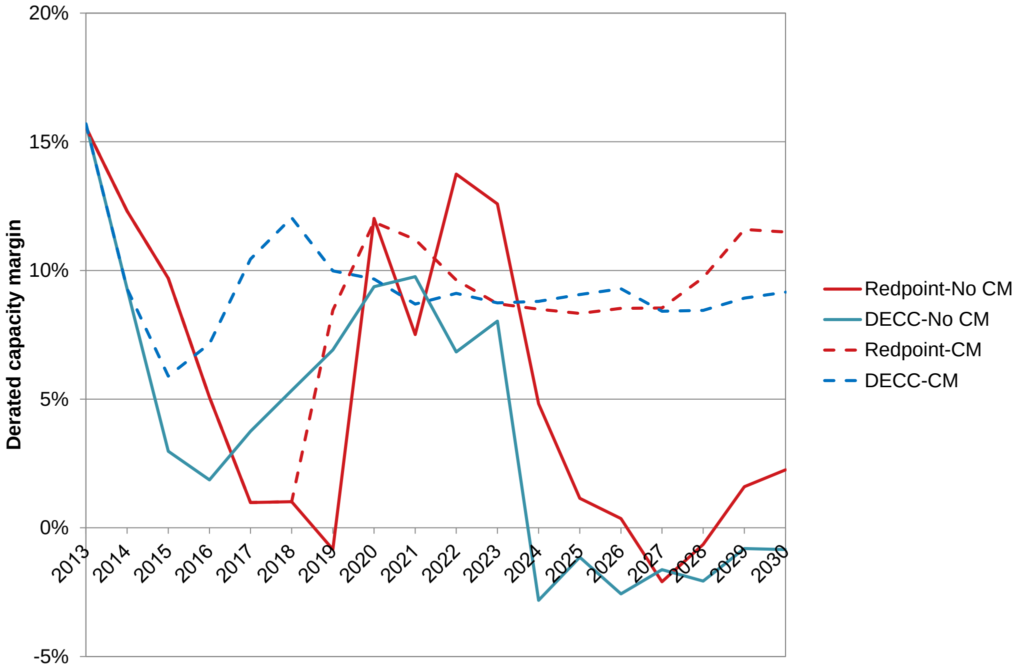
Redpoint modelling

In the Redpoint modelling, the margins reduce from today's levels in both cases as existing coal plant and CCGTs retire. The Capacity Market stabilises capacity margins from 2019, whereas in the No CM case margins are more variable. The large drops in de-rated capacity margins in the No CM cases coincide with the LCPD and IED related closures in the run up to 2016 and in 2023. In the Redpoint model, margins dip below zero for a single year (2027) but this is not sustained and margins recover somewhat by 2030. Margins in the Redpoint No CM case appear lower than in the equivalent October modelling because interconnectors are assumed not to contribute to the reported de-rated capacity margin.

DECC modelling

In the DECC CM case, the Capacity Market encourages some plant to stay open over the period 2016 to 2019. In the DECC No CM modelling, margins decline below zero after the IED related closures in 2023 and do not recover by 2030. In the DECC model, lower margins do not necessarily lead to significant increases in wholesale power prices. Therefore new entry is not attracted to the market to the same extent as in the Redpoint modelling.

Figure 6 **De-rated peak capacity margin (July 2013 assumptions)**[32]



A.2.2 New build and retirements of plant eligible for the Capacity Market

Figure 7 shows the total new build of plant eligible for capacity payments in the CM case, comparing the Redpoint and DECC results. The overall build of new capacity is higher in the Redpoint CM case until 2029.

New CCGTs

The development of new CCGTs is higher in the Redpoint modelling than in the DECC modelling, with 24 GW deployed by 2030. This is a result of higher expected profitability in the energy market for new CCGTs, and hence lower bids in the Capacity Market. The amount of missing money is less for CCGTs than in the equivalent DECC case. This results in new CCGTs being competitive in the Capacity Market with existing plant and new OCGTs, which is not the case in the DECC modelling. In the DECC modelling, new CCGTs are built if annual build limits for new OCGT has been reached.

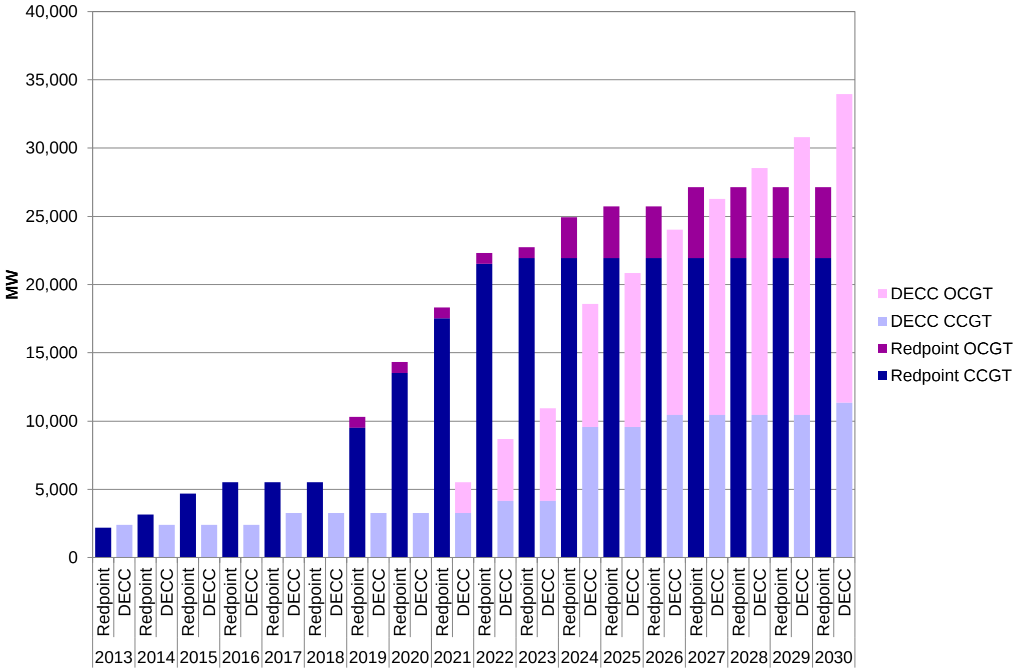
Compared to the Redpoint October modelling, new CCGTs are less profitable in the Redpoint July modelling because there is more domestic generation capacity. This effect has less impact on low load factor existing CCGTs.

New OCGTs

New OCGTs, being more competitive than new CCGTs, are a deployed at a large scale from 2019 in the DECC DDM modelling, whereas in the Redpoint CM case only 5 GW of new OCGT is constructed by 2030 and in the Redpoint No CM case no new OCGTs are built.

[32] In the July modelling interconnectors are assumed not to contribute to the derated margin throughout the modelling period.

Figure 7 Total new build for thermal capacity (CM cases, July 2013 assumptions)[33]

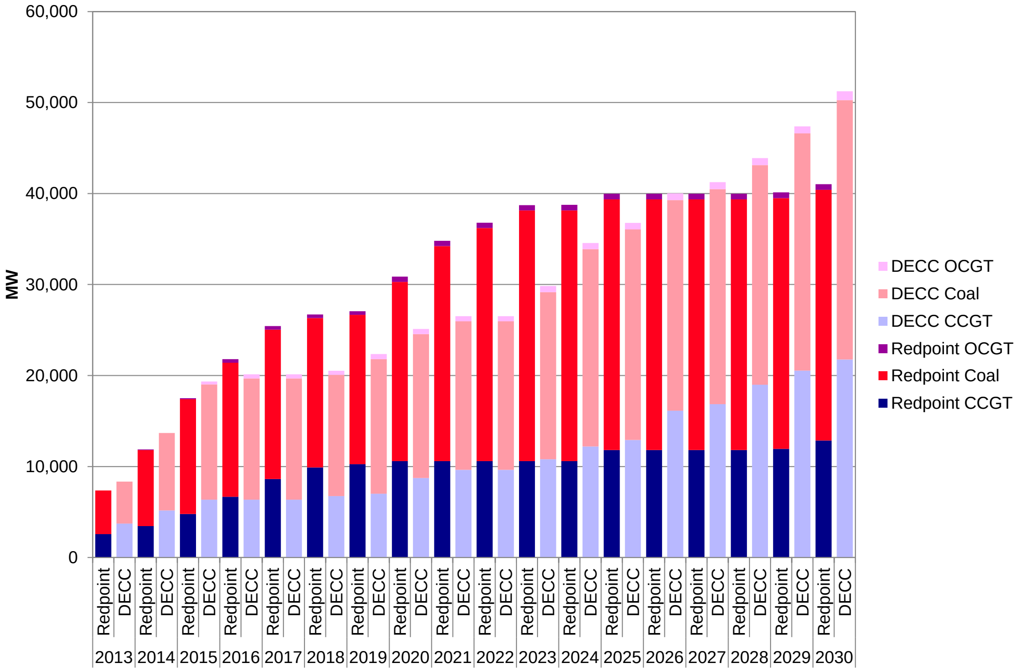


The Redpoint CM case has more rapid retirements relative to the DECC CM case (Figure 8) until 2025, as a result of coal retirements. This is because these plant are less competitive with CCGTs given their higher fixed costs and assumed lower ancillary services revenues. In the latter half of the 2020s, the Redpoint model keeps existing CCGTs open as new CCGTs are no longer competitive, whereas these retire in the DECC modelling to be replaced by new OCGTs.

CCGT retirement in both models in the near term is a result of low running hours and profitability in the wholesale electricity market. The Redpoint CM case delays the retirement of existing CCGTs as these plant bid in based on relatively low fixed costs, which are lower than the fixed costs and capital return required by new OCGTs. These plant also have the ability to convert to open-cycle to reduce their costs further. By 2030, the DECC CM case involves more retirement of existing CCGTs to be replaced by new OCGTs.

[33] Includes CCGTs returning from mothball

Figure 8 Total retirement stack for thermal capacity (CM cases)



A.2.3 Wholesale power prices

The wholesale power prices in each of the four cases are shown in Figure 9. In the near term, the wholesale prices in the Redpoint model are £3/MWh higher than in the DECC modelling. This is consistent with the differences observed using the October IA assumptions.

Redpoint modelling

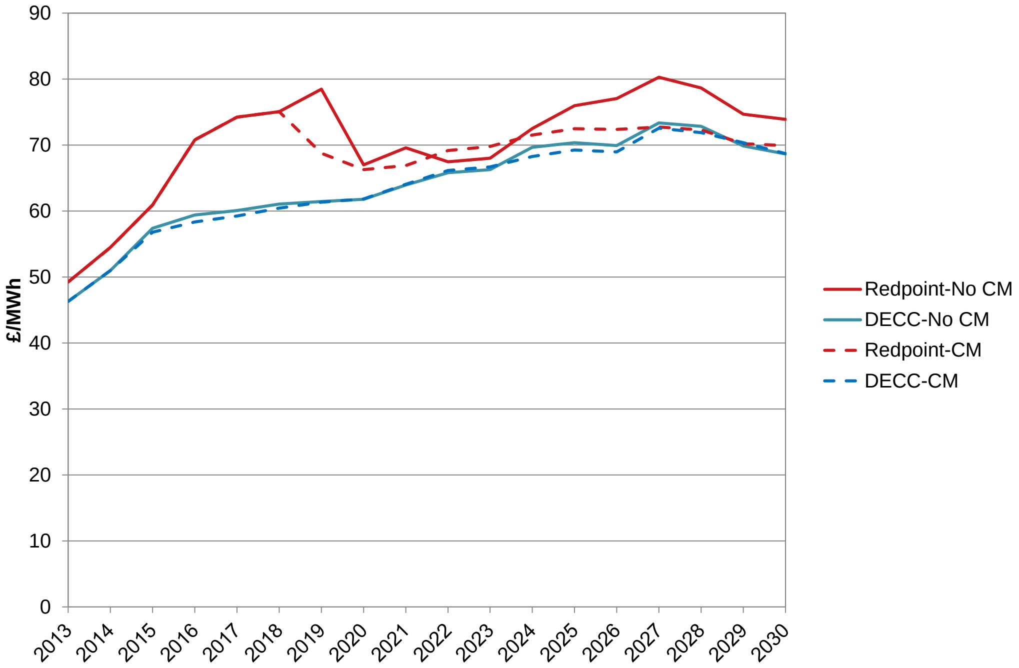
As capacity margins begin to tighten from 2016 onwards, wholesale prices in the Redpoint modelling increase. This is due to the parameters of the calibrated uplift function, which increases prices when period-by-period margins are tight (Section 3.2). The lack of responsiveness in the wholesale power prices to tight capacity margins is notable in the DECC modelling. As discussed below, this reduces the benefit to consumers of lower wholesale prices resulting from the higher de-rated capacity margins promoted by the CM.

In the Redpoint modelling, wholesale prices are typically higher in the No CM case. However, this is reversed in 2022 and 2023 when the No CM case has higher de-rated capacity margins than the CM case.

DECC modelling

In the DECC modelling, wholesale power prices do not respond as strongly to tighter capacity margins and are much closer between the No CM and CM cases throughout the modelling period.

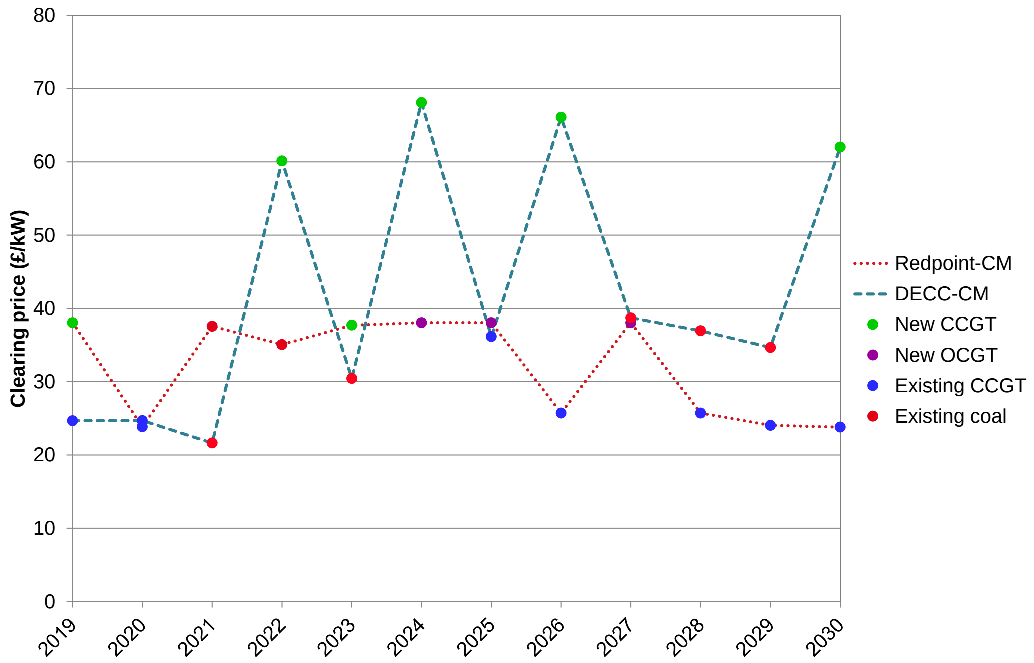
Figure 9 Wholesale power prices (July 2013 assumptions, real 2012)



A.2.4 Capacity Market clearing prices

Capacity Market clearing prices (Figure 10) show a different pattern between the two sets of modelling. In the DECC case the higher values are set by the offer price of new CCGTs (and align to the years in which new CCGT is commissioned). In the interim years, new capacity comes from new OCGTs only and clearing prices are set by existing plant. The clearing prices in the Redpoint CM case are set by a mixture of existing and new plant. The differentials in offer prices between new and existing plant are smaller in the Redpoint modelling, which means the clearing prices are less volatile when the price setting plant switches between existing and new plant. New CCGTs are the best new entrant until 2023 with new OCGTs being more competitive after this point.

Figure 10 Capacity Market clearing prices (July 2013 assumptions, real 2012)



A.2.5 Cost Benefit Analysis

Redpoint modelling

The Cost Benefit Analysis for the Redpoint modelling (Table 10) shows a net welfare increase under the CM. The major drivers are the savings in the costs of unserved energy, which is reduced due to the additional capacity in the CM case. The savings in capital costs are a result of a reduction in the CCGT capacity built by 2030 relative to the Redpoint No CM run, replaced by OCGT capacity. Offsetting this, the higher fuel costs of the generation mix (due to existing plant being less efficient than new CCGTs) increases generation costs.

In the Redpoint analysis, consumers are worse off in the CM case after 2020, because the additional cost of capacity payments is not outweighed by the savings in costs of unserved energy and the reduction in the costs of wholesale energy. The increase in the average annual domestic consumer bill over the period 2016-2030 due to the CM is £6. Conversely, producers receive a net benefit from the introduction of the CM.

Table 10 Redpoint Cost Benefit Analysis (July 2013 assumptions)

Change in welfare (£m, 2012 real)		NPV (2013-2030)	NPV (2013-2020)	NPV (2021-2030)
Net Welfare	Carbon costs	210	10	200
	Generation costs	-230	-10	-220
	Capital costs	430	-210	640
	Unserved energy	2040	480	1560
	Change in Net Welfare	**2450**	**260**	**2190**
Distributional analysis				
Consumer Surplus	Wholesale price	10430	2870	7560
	Low carbon payments	-3000	-280	-2720
	Capacity payments	-12660	-2430	-10230
	Unserved energy	2040	480	1560
	Change in Consumer Surplus	**-3190**	**640**	**-3820**
Producer Surplus	Wholesale price	-10430	-2870	-7560
	Low carbon payments	3000	280	2720
	Capacity payments	12660	2430	10230
	Producer costs	48-	-200	670
	Change in Producer Surplus	**5700**	**-360**	**6060**
Environmental Tax	Change in Environmental tax revenue	**-70**	**-20**	**-50**

DECC modelling

Overall there is a welfare increase of £400m in the DECC modelling. The savings in unserved energy are similar to the Redpoint modelling. However, this is partially offset by increases in capital and generation costs, and by increases in system costs.

In DECC's modelling, consumers are worse off in a CM world by more than in the Redpoint modelling. The increase in the average annual domestic consumer bill over the period 2016-2030 due to the CM is £17.

Table 11 DECC DDM Cost Benefit Analysis (July 2013 assumptions)

Change in welfare (£m, 2012 real)		NPV (2013-2030)	NPV (2013-2020)	NPV (2021-2030)
Net Welfare	Carbon costs	-240	10	-250
	Generation costs	-360	-290	-70
	Capital costs	-330	-10	-320
	System costs	-1,210	-350	-860
	Unserved energy	2,520	240	2,280
	Interconnectors	20	10	10
	Change in Net Welfare	**400**	**-400**	**810**
Distributional analysis				
Consumer Surplus	Wholesale price	2,140	980	1,160
	Low carbon payments	-330	-90	-230
	Capacity payments	-15,770	-1,790	-13,970
	System costs	-1,210	-350	-860
	Unserved energy	2,520	240	2,280
	Change in Consumer Surplus	**-12,640**	**-1,020**	**-11,630**
Producer Surplus	Wholesale price	-2,120	-970	-1,150
	Low carbon support	330	90	230
	Capacity payments	15,770	1,790	13,970
	Producer costs	-930	-270	-660
	Change in Producer Surplus	**13,040**	**640**	**12,400**
Environmental Tax	Change in Environmental Tax Revenue	**10**	**-30**	**30**

Summary

The Redpoint and DDM results show differences in build and retirements, that can be attributed to the different profitability of generation types in the dispatch modelling.

The net welfare savings in the Redpoint modelling come from savings in unserved energy and capital costs. The DECC modelling shows similar savings but this is offset by increases in system costs.

The value of the wholesale price savings to consumers under the CM are higher under the Redpoint modelling and this leads to an overall lower increase in domestic consumer bills in the Redpoint results compared to the DECC results.

B Investment Decision Model

B.1 Model outline

The IDM incorporates a market dispatch engine and simulates plant investment and retirements based on future expectations of earnings. It was this model which was used in the original EMR analysis for DECC in support of the 2010 consultation, and the following policy development (prior to DECC's implementation of the DDM). The IDM has also been used to support analysis for private sector clients on future wholesale electricity prices and capacity market revenues.

The model is capable of analysis of transmission constraint costs and transmission investment (for example as used for Redpoint's modelling for Ofgem's Project TransmiT[34]) but this functionality has not been used for the current analysis.

B.2 Model description

Investment in generation capacity in deregulated electricity markets is driven primarily by the profit-maximising intentions of market participants. This decision-making may not lead to capacity mixes and market operation that are consistent with the goals of policy makers, namely targets for security of supply, environmental standards and diversification of plant portfolios.

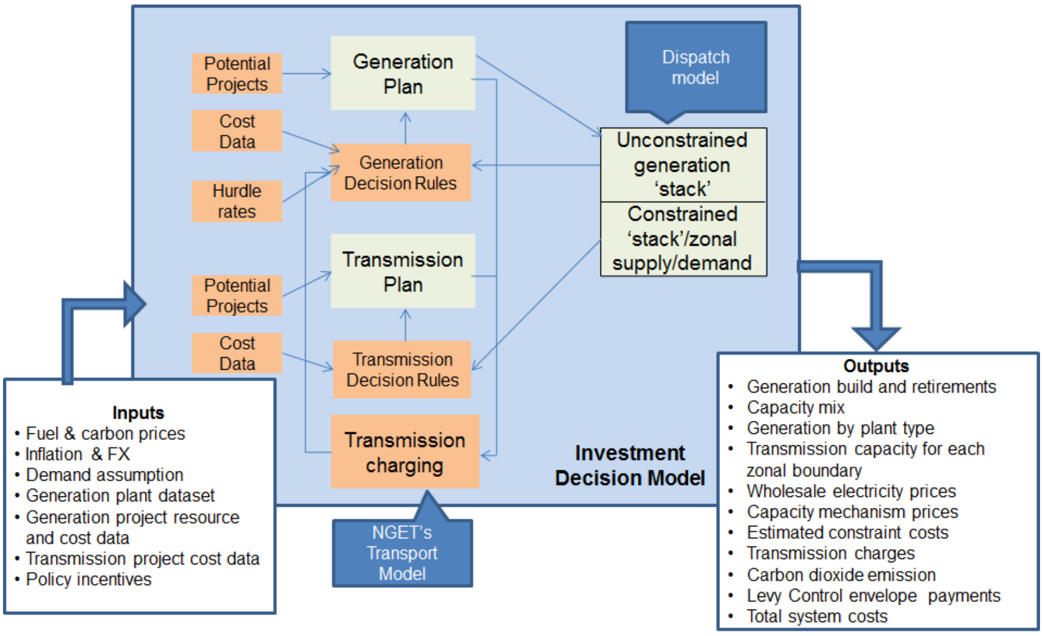
Furthermore, the investment decision-making of market participants is undertaken with imperfect information, due to a lack of forward visibility around fuel prices, investment costs, future policy and the general evolution of the capacity mix. Modelling such markets requires a tool that is able to mimic the actual decision-making process of investors, accounting for limited foresight on the part of investors, and interventions on the part of policy-makers.

We have developed a suite of tools which model the dynamic investment decision-making of market participants through time, as plant mixes, policies and pricing dynamics evolve. These tools operate in both the long and short term, with investment (and retirement) decisions on an annual basis made in response to changes in pricing dynamics and security of supply metrics.

Figure 11 shows the IDM modelling suite. The model takes as inputs the scenario assumptions such as fuel prices and electricity demand. We also have the ability to layer on assumptions about policy options such as the RO, CfDs and the Capacity Market (discussed below).

[34] https://www.ofgem.gov.uk/sites/default/files/docs/2013/08/cmp-213-modelling-review-of-cmp213-impact-assessment-modelling-for-ofgem-%28redpoint-energy%29_0.pdf

Figure 11 Investment Decision Model



The modelling suite gives results on capacity, generation, carbon dioxide emissions, wholesale power prices and capacity payments. The model also produces a full comparative Cost Benefit Analysis including allocation effects between consumers, producers and government.

B.3 Investment and retirement decisions (No CM)

The IDM is based on an agent simulation engine that aims to mimic players' decision-making in the GB power market.[35] The model contains an extensive list of potential new-build projects in the GB power generation sector according to their size, potential location and earliest possible year of operation.

For each year, the levelised cost of energy (LCOE) of potential new-build projects are compared against their expected revenues (given assumed load factors, future price expectations, and ancillary services) and where costs are less than expected revenues, projects are moved first to a planning stage, and subsequently, if still economic, to a committed development phase. Additionally, retirement decisions for existing plant are also made on the basis of near term profitability expectations. A 5-year forward-looking view for investing in a new plant is assumed and a 1-year forward-looking view for plant retirement decisionsThe logic for new investments is shown in Figure 12 below. For new generators the levelised non-fuel cost includes capital costs and annual fixed costs. The gross margin is calculated as the expected margin from power revenues and ancillary services less fuel and carbon costs and non-fuel variable costs.

There are two trigger points which a project must pass in order to progress to construction. If a project is "in the money" it enters planning. If it continues to be in the money at the end of the planning period, the project is committed to the construction phase, and will become operational after a pre-defined number of years.

[35] The functionality of the Investment Decision Model (IDM) is explained in greater detail in our report which supported DECC's EMR Consultation in December 2010, entitled "Electricity Market Reform – Analysis of policy options". See http://www.decc.gov.uk/assets/decc/Consultations/emr/1043-emr-analysis-policy-options.pdf

Total annual investment in a particular technology is limited by the global build constraint, defined in MW. This imposes an additional constraint which limits the total rate of deployment of a particular technology. If this constraint is binding, the projects with the highest expected returns will progress.

Figure 12 Generator build decisions

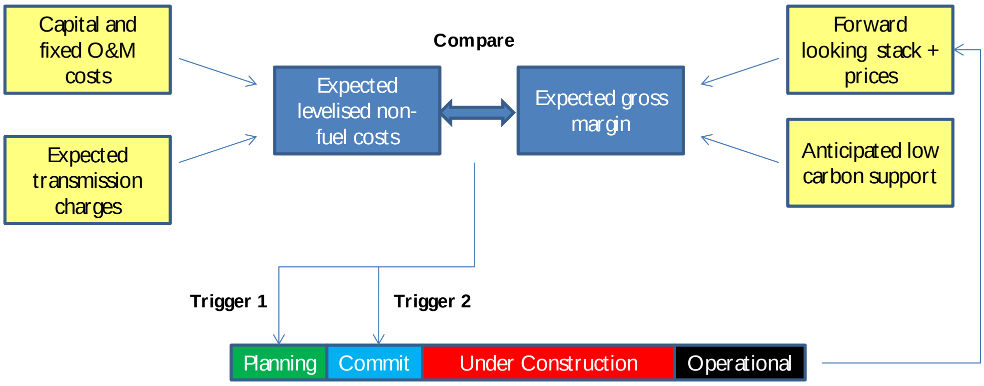
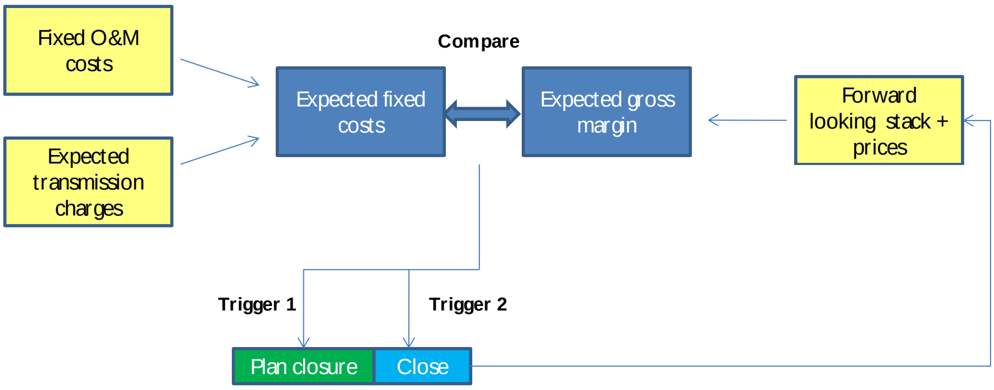


Figure 13 shows the logic for closure decisions of existing generators. The logic is analogous to that for new investments, with the difference that capital already invested is ignored as this is a sunk cost.

Figure 13 Generator closure decisions



B.4 Investment and retirement decisions (with CM)

The Capacity Market module within the IDM incorporates a capacity auction that considers the additional earnings that plant need to cover fixed costs (and capital costs for new plant) relative to expected earnings.

Generator offer prices are determined by evaluating the additional revenues they require above expected wholesale market revenues (and revenues earned from the provision of balancing services) to stay open or build a new plant. For existing generators, this is the margin made in the wholesale market less all variable costs and fixed annual costs. For new projects, this also includes the annuitised capital cost of the project.

The assumed contract length is 1 year for existing plant and ten years for new plant. We do not model 3 year contracts for refurbished plant.

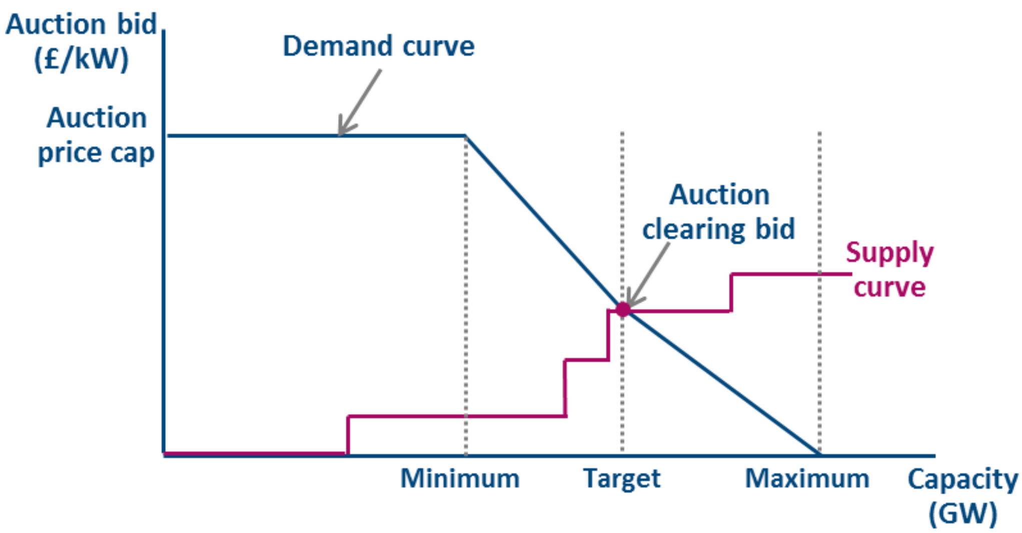
CfD and RO-funded plant as well as interconnected capacity are assumed not to receive capacity payments, although their capacity credit is taken into account when setting the level of capacity to contract for.

Generators offer their de-rated capacity factors into the auction. The de-rating factors are described in Section 3.2. The auction is based on a stack of all the offer prices, where the volume element is the de-rated capacity of the generators.

Once a generator has physically closed it cannot re-enter the auction in a later year – i.e. the possibility of mothballing capacity is not considered except as an exogenous assumption.

The capacity requirement in the model is set as a percentage over peak demand (a proxy for the Reliability Standard based on LOLE that has been proposed). The central point for the CM demand curve is set as peak demand plus 10%. We have implemented DECC's latest proposals for a demand curve (as described in Section 2.1) based on a price cap of 1.5 times Net CONE (set at 1.5 GW below the capacity requirement), and value of zero at 1.5 GW above the capacity requirement. An example demand curve is shown in Figure 14.

Figure 14 - Capacity Market supply and demand (example)



The model finds the point in the stack at which the de-rated capacity intersects the demand curve. The offer price of this marginal generator then sets the capacity price for that year. The mechanism will clear either on older existing plant which would otherwise be losing money, or on potential new build. If new build projects clear in the auction, the model assumes that this plant will subsequently be built. Where a new plant has secured a longer term contract, the model assumes that this plant offers capacity into subsequent auctions at zero price for the duration of the contract, while they are being paid the contracted level. Where a plant fails to clear in the Capacity Market, it will receive no capacity revenues which leads to its closure.

The outputs of the Capacity Market Module for each modelled year are the auction clearing price (£/kW), the Capacity Agreement allocation, the identities of the plant which have cleared in the auction, and the total capacity payments (£m).

Generator bidding behaviour

Generator bids are built up as follows. We assume that generator bids are based on the additional revenue required to cover annual fixed costs (existing plant) or fixed and capital costs (new plant). These assumptions are described in Section 3.1.

We assume that new plant will base their offers on the revenue expectation over the full economic life of the plant (rather than say trying to recover the full cost over the 10 year contract). We assume that generators have full confidence that the policy will maintain de-rated capacity margins at a level close to 10 %. We assume that no attempt to game the market or exercise market power. We assume that the Capacity Market does not change 'bidding' behaviour in the wholesale market, and that generators are still able to extract scarcity rents associated with temporal market power when the system is tight.