Electricity Balancing Significant Code Review (EBSCR)

Quantitative analysis to support Ofgem's Impact Assessment

CLIENT: Ofgem

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Version History

Version	Date	Description	Prepared by	Approved by
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EXECUTIVE SUMMARY

Background

The balancing arrangements are an integral part of any electricity market designed around the principles of self-dispatch and bilateral contracting between generators and suppliers. The arrangements provide the platform by which the System Operator (SO) is able to maintain a physical balance between supply and demand on a second by second basis and at each point on the network, and provide the price signals which incentivise market participants to balance their own energy positions at a half-hourly level.

The primary balancing tool available to the SO is the Balancing Mechanism (BM) in which generators and some providers of demand side response are able to submit bids and offers to increase or decrease generation and demand. The SO also has access to pre-contracted Balancing Services which it is incentivised to use where this can be cheaper than buying in 'real-time' from the BM.

The nature of the Balancing and Settlement Code (BSC) governance arrangements has meant that progress has been relatively piecemeal, and Ofgem has continued to express concerns about the efficiency of the arrangements, most notably in its 2009/10 Project Discovery. The change of governance arrangements with the introduction of the Significant Code Review process allows for a more holistic approach to the future development of the arrangements. Having previously consulted with industry, it decided to launch an Electricity Balancing SCR (EBSCR) with a broad scope in August 2012.

As part of the EBSCR Ofgem will publish an impact assessment (IA) alongside both its draft and final decision which will capture its assessment of both quantitative and qualitative impacts of policy options under the EBSCR. The three high-level objectives of the review are to:

- Incentivise an efficient level of security of supply
- Increase the efficiency of electricity balancing, and
- Ensure the balancing arrangements are compliant with the European Target Model (TM) and complement the Electricity Market Reform (EMR) Capacity Mechanism (CM)

This document relates to the quantitative part of the impact assessment. Ofgem contracted Baringa Partners (incorporating Redpoint Energy) to provide support for the modelling of the potential impacts of potential cash-out policy packages.

Policy options and packages

Ofgem has considered a number of potential policy options as part of the EBSCR including:

- Making cash-out prices more marginal
- Single versus dual cash-out pricing
- Including uncosted demand control actions in the calculation of cash-out prices, primarily voltage control and load disconnection (unserved energy), at the Value of Lost Load (VOLL), and
- Better allocation of pre-contracted reserve costs via a Reserve Scarcity Price function (RSP)

The individual policy considerations have been combined by Ofgem into five potential policy packages shown in the table below. The analysis of these packages is presented in this report.

Table 1 Policy packages considered

<table>
<tr><th>Package</th><th>Marginality of price (PAR MWh)</th><th>Single / dual price</th><th>Uncosted actions</th><th>Allocation of reserve costs</th></tr>
<tr><td>DN</td><td>500</td><td>Dual</td><td>No VoLL</td><td>Current</td></tr>
<tr><td>P1</td><td>50</td><td>Dual</td><td>No VoLL</td><td rowspan="5">Reserve Scarcity Price Function (RSP)</td></tr>
<tr><td>P2</td><td>1</td><td>Single</td><td>No VoLL</td></tr>
<tr><td>P3</td><td>1</td><td>Dual</td><td>Apply VoLL and compensate interrupted parties</td></tr>
<tr><td>P4</td><td>50</td><td>Single</td><td>Apply VoLL and compensate interrupted parties</td></tr>
<tr><td>P5</td><td>1</td><td>Single</td><td>Apply VoLL and compensate interrupted parties</td></tr>
</table>

Approach

For the quantitative analysis, the impact of different policy packages on cash-out prices, system balancing, security of supply and party cash-flows was explored through three separate modelling ‘iterations’. These iterations require increasingly sophisticated analysis, and a corresponding increase in the number of assumptions:

- ***Iteration 1****:* aims to calculate the instantaneous impact on cash-out prices and subsequent party cash-flows under each policy package, assuming no change in parties’ behaviour. This is the simplest and most transparent iteration of the analysis and is based on application of the policy packages to historical data. *Ofgem led this part of the analysis.*
- ***Iteration 2***: aims to calculate cash-out prices in five-yearly spot years from 2015 to 2030 under the different policy packages. In this iteration it is assumed that in the Short Term (ST) the only tool available to parties to manage their imbalance risk is through systematically lengthening or shortening the bias (hedge) in their positions when entering imbalance settlement.
- ***Iteration 3***: is similar to Iteration 2 in that it estimates forward looking cash-out prices to 2030. However, in addition to any short-term response in systematic bias, it also examines the impacts assuming that parties could invest in Longer Term (LT) measures to allow them to manage better their imbalance risk (e.g. forecasting improvements) or investing in additional generation capacity or demand side response measures.

Iteration 1 utilises only historic data, whereas Iterations 2 and 3 require a Cash-Out Model (COM) calibrated to historic data that can simulate changing party behaviour in response to changing cash-out exposures. These latter two iterations are the focus of this report.

Iterations 2 and 3 are based around a 'top-down' Monte-Carlo simulation of cash-out prices, which has been calibrated such that it can reproduce reasonably accurately the distribution of recent historic cash-out prices. The model effectively simulates the balancing accuracy of individual parties to calculate Net Imbalance Volumes (NIV), and compares these volumes to simulated 'Energy Balancing Cost Curves' (EBCC) to generate a cash-out price.

The EBCCs replicate the potential BM Bids and Offers available to resolve energy imbalances in a half hourly settlement period[1]. The EBCCs evolve both within a settlement period, due to changing simulated fuel and carbon prices and the impact of the RSP, and over time due to changes in the underlying capacity mix as a result of plant retirements and additions, and additional investment in demand side response.

The COM also contains a series of monthly regression models, estimated from historic data, which generate the within-day market price, the Market Index Price (MIP), in each settlement period based on the calculated cash-out prices and other simulated values in the model (e.g. gas prices or capacity margin). The cash-out prices and MIP are combined with the parties' imbalance data to generate party-level cash flows (e.g. net imbalance charges and RCRC) so that the distributional impact on different party types of cash-out changes can be explored.

A set of simulations is undertaken for a characteristic day in each month across the spot year. ST changes in party bias are calculated endogenously as part of the model whereas LT choices around possible investment are tested by exogenous scenarios, using outputs from Iteration 2 of the modelling.

Under iterations 2 and 3 a set of simulations to 2030 is undertaken for Do Nothing (DN) and under each EBSCR policy package. A Cost Benefit Analysis (CBA) from the consumers' perspective was undertaken for each package and compared to DN.

Ofgem wished to explore the impact of cash-out reform on long term investment in isolation of a potential future CM. However, we also explored sensitivities with a CM in place. Since the analysis was undertaken, Government has confirmed its intention to implement the CM with the first capacity auctions taking place in 2014.

Conclusions

In the absence of cash-out reform, the changing generation mix under a potentially tightening capacity margin (particularly in a world where the CM is not implemented)[2], will likely drive significant increases in the costs of energy balancing over the next two decades. For example, under the Do Nothing case Gross Imbalance Volumes could rise from ~30 TWh/year at present to ~80 TWh/year by 2030 due primarily to increasing amounts of renewables on the system; with the overall cost of energy balancing to the consumer[3] potentially doubling by 2020 (from ~£74m/year) and increasing by a factor of ten to 2030. The costs of system balancing, such as

[1] The EBCCs have been constructed synthetically to remove bids and offers that are used solely for resolving system balancing requirements such as locational balancing.

[2] Capacity margins are based on scenario modeling from DECC's 2012 Capacity Market Impact Assessment – see section 3.2 for further details. This study has explored two main scenarios out to 2030 under a case where the CM is not implemented and one where it is.

[3] As defined in Appendix B: 8.2.

locational balancing, could also rise dramatically over this period but this was not a focus of this study.

The additional energy balancing costs will result in higher imbalance charges for out of balance parties (for example, imbalance opportunity costs[4] for independent wind generators could rise from ~£1/MWh[5] today under DN to over £5/MWh in 2020 and over £10/MWh in 2030); although under current rules the full extent of the additional costs may not be reflected in cash-out prices. The modelling suggests that System Buy Prices (SBPs) will rise over time, but that after 2015 System Sell Prices (SSPs) will start to fall as bids from subsidised low carbon generation are captured within the cash-out price calculation. By 2025, the average SSP is expected to be negative. This will result in a greater spread in cash-out prices which is expected to influence player behaviour. The risk of being exposed to potentially very high negative SSPs for being long may become as material as the risk of exposure to very high SBPs for being short, and thus the current incentive to adopt a systematically long position may change. For example, the modelling suggests that greater marginality in cash-out prices reinforces incentives to go long in 2020, but by 2030 the effect is broadly reversed, albeit with variations across the year. Under single pricing, the incentives are different again since parties are rewarded for being out of balance in the opposite direction to the system.

Increasing the marginality of PAR, including the RSP and costing demand control actions appears to be justified in terms of signalling the value of peak energy and flexibility, and possibly stimulating additional investment in demand side response and new generating capacity under a tight system.

For example, the incremental impact of moving from PAR500 to P50 (excluding the effect of the RSP and costing demand control) adds around £10/MWh to average SBP (when it is the main price) in 2020 and £15/MWh in 2030. The combined impact of more marginal PAR1, RSP and costing of demand control actions under P3 and P5 leads to a much sharper SBP when it is the main price; ~£15/MWh higher on average in 2020 and ~£27/MWh higher in 2030, under the core scenario without the CM, compared to DN.

The modelling suggests that under P5 the impact of the cash-out reform on market prices in a tight market in 2030[6] is equivalent to a price signal which could in theory support around 3 GW of additional capacity. These reforms to cash-out should also encourage greater imports into the GB market under conditions of system stress, and provide effective signals for the dispatch of flexible generation and demand side response. The combined impact of the cash-out reforms should reduce the risk of load disconnection or voltage control to very low levels.

The modelling suggests that the current dual pricing approach, with a wide (and expected widening) spread between SBP and SSP, leads to imbalance charges which on average are greater than the underlying costs of balancing the system. Sharpening cash-out prices should signal the value of peak energy but compound this ‘over-charging’ for imbalances under normal conditions. This could lead to inefficient investment to improve private balancing performance

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[4] We use the term here to represent the loss to a party that is incurred by being out of balance as opposed to settling its entire position in the wholesale energy market.

[5] Per MWh of credited energy generated or supplied.

[6] Under a bespoke scenario provided by DECC, which assumes no Capacity Market is implemented and with a de-rated annual capacity margin of ~1.5% in 2030.

which cannot be justified in terms of savings in energy balancing costs at the system level. Packages with single pricing appear to align incentives for parties to invest in their own balancing improvement much more closely with the overall system-wide benefits from this investment, in terms of reduced balancing costs, and in the long term may lead to more efficient outcomes. The incentives to make provisions for covering peak conditions are the same as for the equivalent dual pricing options, but the incentives to balance under normal conditions are weaker as a result of the potential reward from being out-of-balance in the opposite direction to the system.

The differences between the dual and single price packages are also reflected in the distributional analysis. For independent players, who traditionally have been weaker balancers, the impact of sharper cash-out prices would be to increase balancing costs. However, the modelling of packages with single pricing suggests that the disbenefit to independent players of sharper cash-out price signals could be offset by removing the cost of dual pricing. This is particularly the case for independent suppliers. For independent wind generators the relative benefits of single pricing do depend, to some extent, on the degree of correlation in their forecast errors, and as a result the frequency with which wind generators are out of balance in the opposite direction to the system[7].

The modelling suggests that consumers would be net beneficiaries of all of the cash-out policy packages in a system with tight capacity margins (up to ~£0.5/MWh after accounting for the benefits of a reduction in unserved energy), and any additional costs in a well-supplied system would be small or neutral. Given the additional benefits to security of supply, not all of which could be quantified, reforms to cash-out seem to be warranted. The negative distributional impacts of sharper cash-out prices could be mitigated through single pricing, which suggests that Packages P2, P4 and P5 may be preferred.

The modelling suggests that differences between these three packages are relatively modest given that the move to at least PAR 50 MWh and the introduction of the RSP, common to all packages, marks the biggest difference with DN. However, not all of the differences can be quantified. P5 would likely provide the greatest benefits to security of supply, primarily as a result of the most significant price signal for new investment due to both PAR1 and costing of demand control actions. There are some limited residual risks associated with PAR1 due to system pollution or 'rogue' bids (e.g. from subsidised generators bidding significantly below the opportunity cost of their subsidy[8]) occasionally setting the cash-out price. P4 with PAR50 would help mitigate against this, but at the expense of less cost-reflective pricing and a weaker investment signal compared to P5.

The analysis in this report has primarily focused on the impact of the cash-out policy packages in isolation of other policy measures. The introduction of the CM under EMR may be a more

[7] With greater correlation (e.g. if more use is made of a small number of aggregators) this will decrease the natural offsetting effects that occur across all wind generators in their forecast errors (as opposed to their outputs). With both greater correlation and increasing volumes of wind, independents would become a bigger driver of overall system imbalance and by definition appear less frequently in the opposite direction to the system imbalance, and hence gain more limited benefit as a result of single pricing.

[8] Although the Transmission Constraint Licence Condition should improve the cost reflectivity of wind bidding and alleviate some of the potential for this to occur.

important driver for investment in new capacity (demand side response or new generating capacity) than cash-out reform. It is important to ensure not to double count the benefits of greater security of supply across the two reform programmes. However, cash-out reform still has a role to play in signalling efficient plant dispatch, utilisation of demand side response, and ensuring efficient flows on interconnectors. The modelling suggests that customers remain net beneficiaries of the single pricing packages (P2, P4, P5) even with a CM in place. Hence, reform to cash-out can go hand in hand with the introduction of the CM. Provided that participants know of the changes to cash-out before offering into the first capacity auctions, and offer competitively, customers should not necessarily be exposed to higher costs from introducing both cash-out reform and the CM. It is also important to note that the risk of exposure to non-delivery penalties under the CM may start to influence player behaviour as much as cash-out risk. In turn this could affect the average system balance and cash-out prices, the modelling of which was outside the scope of this study. Further analysis in this area may be required.

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

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LIST OF ACRONYMS

Standard	Project specific
BETTA – British Electricity Trading and Transmission Arrangements	COM – Cash Out Model
BPA – Buy Price Adjuster	EBCCs – Energy Balancing Cost Curves
BM – Balancing Mechanism	LD – Load Disconnection
BMU – Balancing Mechanism Unit	LT – Long Term
BOA – Bid Offer Acceptance	OC – Opportunity Cost
BSAA – Balancing Services Adjustment Action	OB – Opportunity Benefit
BSC – Balancing and Settlement Code	RSP – Reserve Scarcity Price Function
BSUoS – Balancing Services Use of System Charges	ST – Short Term
CADL – Continuous Acceptance Duration Limit	VC – Voltage Control
CBA – Cost Benefit Analysis	
CfD – Contract for Difference	
CM – Capacity Market	
CSOBM - Cost of System Operation in the Balancing Mechanism	
DSR – Demand Side Response	
EBSCR – Energy Balancing Significant Code Review	
EEU – Expected Energy Unserved	
EMR – Electricity Market Reform	
FPN – Final Physical Notification	
GC – Gate Closure	
GCV – Gross Calorific Value	
MIP – Market Index Price	
NIV – Net Imbalance Volume	
PAR – Price Average Reference (volume)	
RCRC – Residual Cashflow Reallocation Cashflow	
RO – Renewables Obligation	
SBP – System Buy Price	
SO – System Operator	
SPA – Sell Price Adjuster	
SRMC – Short Run Marginal Cost	
SSP – System Sell Price	
STOR – Short Term Operating Reserve	
TM – Target Model	
UEP – (DECC) Updated Energy Projections	
VIU – Vertically Integrated Utility	
VoLL – Value of Lost Load	
VOM – Variable Operating and Maintenance cost	

1. INTRODUCTION

1.1. Background

The balancing arrangements are an integral part of any electricity market designed around the principles of self-dispatch and bilateral contracting between generators and suppliers. The arrangements provide the platform by which the System Operator (SO) is able to maintain a physical balance between supply and demand on a second by second basis and at each point on the network, and provide the price signals which incentivise market participants to balance their own energy positions at a half-hourly level.

The primary balancing tool available to the SO is the Balancing Mechanism (BM) in which generators and some providers of demand side response are able to submit bids and offers to increase or decrease generation and demand. The SO also has access to pre-contracted Balancing Services which it is incentivised to use where this can be cheaper than buying in 'real-time' from the BM.

The prices for imbalance settlement or 'cash-out' are derived from actions taken in the BM and to an extent from the costs of pre-contracted Balancing Services. The calculations of cash-out prices are necessarily complex given the requirement to extract the value of energy in each period from a set of actions taken in real-time for a variety of reasons, not all of which relate directly to gross energy imbalances at a half-hourly level. A fundamental principle behind the British Electricity Trading and Transmission Arrangements (BETTA) is that the costs of energy balancing should be targeted at those participants that cause the imbalances, but that the costs of system balancing (sub-half-hourly, locational, network services) should be socialised.

As a result of this complexity, the balancing arrangements, which were implemented in 2001, have been the subject of two previous reviews[9], and a number of modifications to the Balancing and Settlement Code (BSC) have resulted. These modifications have helped to improve the accuracy of the cash-out price signal, by reducing 'system pollution' in the energy price signal and reducing excessive volatility.

The nature of the BSC governance arrangements has meant that progress has been piecemeal, and Ofgem has continued to express concerns about the efficiency of the arrangements, most notably in its 2009/10 Project Discovery. The change of governance arrangements with the introduction of the Significant Code Review (SCR) process allows for a more holistic approach to the future development of the arrangements. Having previously consulted with industry, it decided to launch an Electricity Balancing SCR (EBSCR) with a broad scope in August 2012. The three high-level objectives of the review are to:

- Incentivise an efficient level of security of supply
- Increase the efficiency of electricity balancing, and
- Ensure the balancing arrangements are compliant with the European Target Model (TM) and complement the Electricity Market Reform (EMR) Capacity Mechanism (CM)

[9] http://www.ofgem.gov.uk/Markets/WhlMkts/CompandEff/CashoutRev/Pages/CashoutRev.aspx

The outcome of the EBSCR is therefore strongly intertwined with security of supply, the success of EMR in integrating large volumes of (relatively inflexible) low carbon generation, the competitiveness of the market and ultimately the price paid by consumers for their electricity.

1.2. Project context and objectives

As part of the EBSCR Ofgem will publish an impact assessment (IA) alongside both its draft and final decision which will capture its assessment of both quantitative and qualitative impacts of policy options under the EBSCR.

This document relates to the quantitative part of the impact assessment. Ofgem contracted Baringa Partners (incorporating Redpoint Energy) to provide support to the modelling of the potential impacts of potential cash-out policy packages.

1.3. Policy options and packages considered

As part of industry workshops supporting the EBSCR process, Ofgem has provided extensive background material on a number of the policy considerations in reforming cash-out[10], and hence they are only summarised briefly below.

More marginal cash-out prices

At present, cash-out prices in a settlement period are calculated as the volume weighted average of the highest/lowest[11] remaining 500MWh of actions in the Net Imbalance Volume stack, after all preceding flagging and tagging rules have been applied[12]. This is known as the Price Average Reference (PAR) volume. Making the PAR smaller more closely aligns the main energy imbalance price with the price of the marginal energy balancing action.

Single versus dual cash-out prices

At present cash-out operates under a dual-price regime whereby the price faced by a party depends on the direction of imbalance of the party relative to the overall system imbalance direction.

Parties out of balance in the same direction as the system are exposed to the main cash-out price reflecting the costs of resolving the energy imbalance on the system in that period, whereas those in the opposite direction (and hence helping to reduce the energy imbalance on the system) are exposed to the reverse, or Market Index Price (MIP). This reflects the price in the within-day market and is meant to be similar to what a party could have attained if it had traded in the market prior to Gate Closure.

Alternatively, under single pricing the reverse MIP is removed and the main SBP and SSP are used for parties out of balance in both directions to the system.

[10] http://www.ofgem.gov.uk/Markets/WhlMkts/CompandEff/electricity-balancing-scr/Pages/index.aspx
[11] Depending upon whether the system is short or long, respectively
[12] See Elexon Imbalance Pricing Guidance for more details
http://www.elexon.co.uk/wp-content/uploads/2013/02/imbalance_pricing_guidance_v4.0.pdf

Table 2 **Dual cash-out price arrangements**

		Length of party	
		Short	Long
Length of overall system	Short	Pay SBP (Main, offer costs in BM)	Paid SSP (Reverse, MIP)
	Long	Pay SBP (Reverse, MIP)	Paid SSP (Main, bid costs in BM)

Table 3 **Single cash-out price arrangements**

		Length of party	
		Short	Long
Length of overall system	Short	Pay SBP (Main, offer costs in BM)	Paid SBP (Main, bid costs in BM)
	Long	Pay SSP (Main, offer costs in BM)	Paid SSP (Main, bid costs in BM)

Under single pricing the incentives for hedging are changed significantly, this is discussed further in Appendix B: 8.1.

Including non-costed demand control actions in cash-out prices

At present the implied costs to consumers of using voltage control[13] to balance the system, or from involuntary load disconnection when it is not possible to balance the system, are not factored into cash-out prices. This is potentially dampening the price signal from cash-out as it not properly accounting for the cost (or value) of balancing the system and maintaining security of supply. The costs of these demand control actions could be included by assigning a price to them in the cash-out price calculation.

Allocation of reserve costs via a Reserve Scarcity Price Function (RSP)

Due to the practical and technical difficulties of balancing the electricity system in real time, as well as commercial incentives to minimise costs, the System Operator (SO) typically procures a range of Short Term Operating Reserve (STOR) contracts in advance that can be drawn upon as needed. This is comprised of both BM-STOR actions, from parties already active in the BM and non-BM STOR actions from parties who are not.

At present, the costs of both forms of STOR are divided into upfront ‘availability fees’ and actual ‘utilisation fees’. The latter are captured directly in the cash-out price calculation[14], whereas the former are captured indirectly through a Buy Price Adjuster (BPA). However, the disaggregation of the costs of STOR into these components means it is difficult to target their overall costs accurately into the settlement periods in which they are used, potentially reducing the cost

[13] Voltage control is an option that can be adopted by National Grid over small time periods that reduces the power drawn (and effective demand) of customers. In addition, it should be noted that the SO can also Max Gen options before disconnections.
[14] With the current exception of non-BM STOR utilisation fees

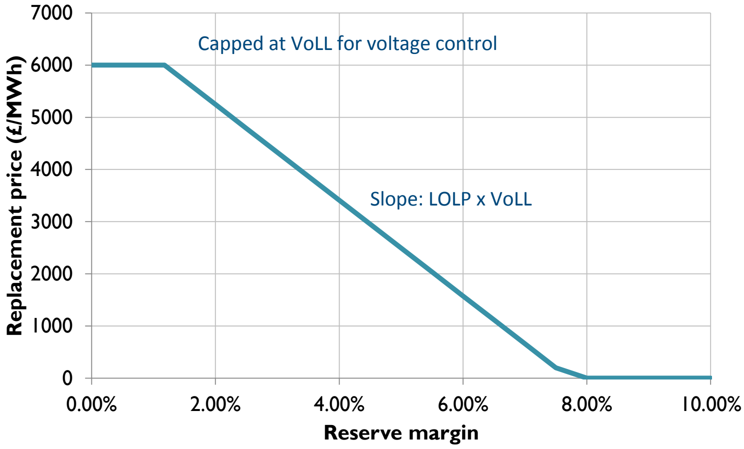
reflectivity of energy balancing actions. In particular, the utilisation fees of contracted STOR providers do not reflect the scarcity value of energy when system conditions are tight, potentially dampening cash-out prices at these times.

Under the RSP, the BPA is removed and STOR actions are re-priced using a single replacement price for each settlement period where a reserve action is utilised and where the replacement price is greater than the utilisation price offered by the unit. The re-pricing is only carried out for the purposes of the cash-out price calculation and does not alter the price paid by the SO.

This price is a function of the 'reserve margin' at or near the time of the settlement period[15] – i.e. the tighter the margin the higher the price. This would cover both BM and non-BM STOR, and would therefore also effectively capture non-BM STOR utilisation fees in cash-out prices, which is not currently the case.

Forms of reserve scarcity pricing exist in some US regional markets such as New York (NYISO), New England (ISONE) and the Mid-West (MISO). Figure 1 below shows the parameters used for the RSP in the modelling. Further details on the specification of the RSP function can be found in Appendix D.

Figure 1 The Reserve Scarcity Price Function



Given the potential rapid increase in replacement price with tightening margin, it is important that the RSP does not unfairly penalise out of balance parties.

The individual policy considerations have been combined by Ofgem into five potential policy packages shown in Table 2 below. The analysis of these packages is presented in this report.

[15] The precise definition of margin for any practical implementation is still to be determined. But, it is broadly the operating margin available to the SO at or near real-time given technical considerations such as near-term plant dynamics, as opposed to an annual capacity adequacy measure of margin (as reported in Ofgem's Capacity Assessment).

Table 4 Cash-out policy packages

Package	Marginality of price (PAR MWh)	Single / dual price	Uncosted actions	Allocation of reserve costs
DN	500	Dual	No VoLL	Current
P1	50	Dual	No VoLL	Reserve Scarcity Price Function (RSP)
P2	1	Single	No VoLL	
P3	1	Dual	Apply VoLL and compensate interrupted parties	
P4	50	Single	Apply VoLL and compensate interrupted parties	
P5	1	Single	Apply VoLL and compensate interrupted parties	

2. MODELLING APPROACH

2.1. Overview

For the quantitative analysis, the impact of different policy packages on cash-out prices, system balancing, security of supply and party cash-flows was explored through three separate modelling 'iterations'. These iterations require increasingly sophisticated analysis, and a corresponding increase in the number of assumptions:

- ***Iteration 1****:* aims to calculate the instantaneous impact on cash-out prices and subsequent party cash-flows under each policy package, assuming no change in parties' behaviour. This is the simplest and most transparent iteration of the analysis and is based on application of the policy packages to historical data. *Ofgem led this analysis and the key results are summarised in Section 4.1*.
- ***Iteration 2***: aims to calculate cash-out prices in five-yearly spot years from 2015 to 2030 under the different policy packages. In this iteration it is assumed that in the Short Term (ST) the only tool available to parties to manage their imbalance risk is through systematically lengthening or shortening the bias (hedge) in their positions when entering imbalance settlement.
- ***Iteration 3***: is similar to Iteration 2 in that it estimates forward looking cash-out prices to 2030. However, in addition to any short-term response in systematic bias, it also examines the impacts assuming that parties could invest in Longer Term (LT) measures to allow them to manage better their imbalance risk (e.g. forecasting improvements) or investing in additional generation capacity or demand side response measures.

Iteration 1 utilises only historic data, whereas Iterations 2 and 3 require a Cash-Out Model (COM) calibrated to historic data that can simulate changing party behaviour. These latter two iterations are the focus of this report.

Iterations 2 and 3 are based around a 'top-down' Monte-Carlo simulation of cash-out prices. This is described in more detail in subsequent sections, but effectively simulates the balancing accuracy of individual party types (see Section 2.3) to calculate Net Imbalance Volumes (NIV), and compares these volumes to simulated 'Energy Balancing Cost Curves' (EBCCs). The EBCCs replicate the potential BM Bids and Offers available to resolve energy imbalances in a half-hourly settlement period.

The simulation is undertaken for a characteristic day in each month across the spot year. ST changes in party position bias are calculated endogenously as part of the model whereas LT choices around possible investment are tested by exogenous scenarios, using outputs from Iteration 2 of the modelling.

Under iterations 2 and 3 a set of simulations to 2030 is undertaken for Do Nothing (DN) and under each EBSCR policy package. A Cost Benefit Analysis (CBA) was undertaken for each package and compared to the DN case.

2.2. Alternative modelling approaches

There are a number of possible approaches to modelling the impact of cash-out reform, each with its own limitations. In any approach, repeated simulation is highly desirable to help understand both the discrete outcomes from cash-out (e.g. mean expected SBP) as well as the likely distribution of outcomes of these values. This is important given the significant uncertainties around the key drivers of cash-out prices, such as possible NIVs.

Bids/Offers into the BM, balancing actions taken by the SO and the subsequent impact on cash-out prices also reflect a complex mix of decisions by different market players and the SO. These are driven by both fundamentals (e.g. plant availability) and by internal strategies (e.g. of portfolio players versus independents).

Two alternative options to the adopted approach were first considered:

- *Bottom-up electricity dispatch model of individual plants* could be used to simulate the costs of system balancing under different conditions, alongside dispatch for the system as a whole. However, this would reflect a perfectly rational (optimised) result for the system as a whole (i.e. if everything was centrally dispatched) rather than the result of different participants bidding into the BM and responding dynamically to the resulting price signals. It would be difficult to mimic existing behaviour and cash-out prices and undertake repeated simulation under this approach. In addition, the focus of the study was to look at cash-out in detail and it is a small part of overall arrangements, so detail and some transparency could have been lost by using a full dispatch model.
- *Bottom-up, agent-based model of all parties in the BM* could be used to simulate parties maximising their revenues or profit in response to: options for bidding in the BM, cash-out prices and options for dispatch in the wider electricity market. The agents' responses over time would be a function of their own actions and other agents' choices affecting the market as a whole. Whilst conceptually appealing, this would be technically challenging to construct reducing the simplicity and transparency of the model, and it would have been difficult to establish reliable input assumptions from available data.

As a result, a key design decision was to develop a 'top-down' simulation model of the key drivers of cash-out which was *well calibrated to historic data in terms of replicating outturn cash-out prices*. The approach was designed primarily to understand how different party types may respond to different imbalance exposures over time and the impact of this on cash-out prices and the wider system.

We adopted this approach as it provides a focussed and targeted approach to modelling changes to the cash-out arrangements, capturing the most significant impacts. This approach provides relatively more flexibility in terms of the assessment of different policy options, but also provides greater transparency in understanding and communicating the results of the modelling.

The proposed approach and scope of the project were tested with the EBSCR Technical Working Group (TWG) at an early stage of the project to review and provide feedback and advice on the proposed modelling methodology. The TWG was composed of a range of industry experts and stakeholders. Comments and assumptions from this TWG were incorporated into the final methodology design.

2.3. Cash-Out Model (COM)

The Cash-Out Model (COM) is the heart of the simulation engine. It simulates the balancing accuracy of BM party types (i.e. the actual versus expected throughput on different production and consumption accounts for parties such as vertically integrated utilities (VIUs) or independent generators). This is used to generate a NIV for the system as a whole in each half-hourly settlement period, on each characteristic day by month, in each spot year considered.

Key simulated inputs include the balancing accuracy of parties, which reflects factors such as demand forecast error for consumption accounts and wind forecast error / outage risk for production accounts. A starting (static) estimate of systematic position bias (estimated from historic data) is also applied, which is subsequently updated via the ST response functionality of the model. This bias represents the party's overall 'hedge' in position when entering imbalance settlement, to minimise their exposure to cash-out prices. See Section 3.7 for further details on how the imbalance properties of parties are simulated in the model.

The simulated NIVs are compared with a set of simulated EBCCs, which mimic the (unpolluted) energy only stack of bids or offers to generate the cash-out prices from the COM, under different policy packages in each half-hourly settlement period on a characteristic day.

A base set of EBCCs was estimated from historic data. These are adjusted over time due to exogenous changes in the underlying capacity mix (e.g. new plant or retirement of existing plant), simulated commodity prices (to alter energy balancing costs and the potential merit order) and simulated demand (to mimic the impact of a tighter / looser system on available energy balancing options).

The COM then takes the cash-out prices and combines them with an estimate of the MIP (used to set the reverse Energy Imbalance Price) to generate the imbalance cash-flows (e.g. NIC, RCRC) by party type and for the system as a whole. The calculation of MIP is dynamic and based on a regression model of the link between simulated cash-out prices (and other key simulated and non-simulated variables in the COM) and within-day market prices[16]. See Appendix A for further details.

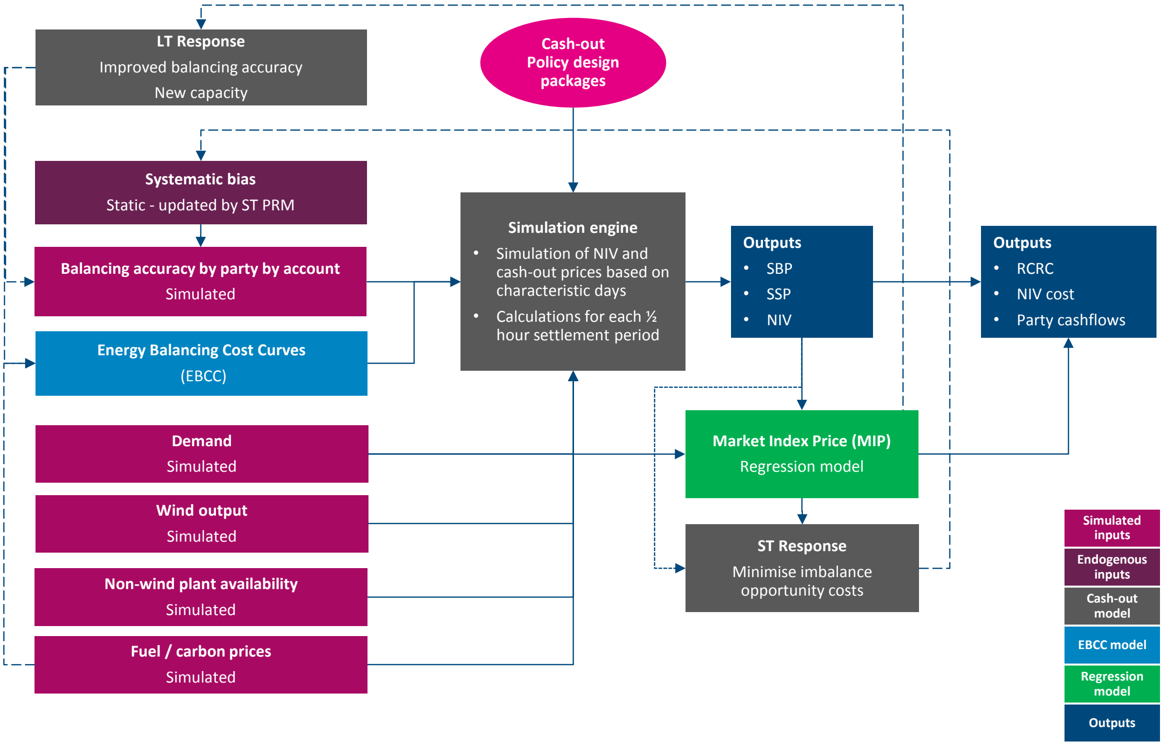
The Short Term (ST) response then examines the extent to which each party could act to minimise its *'Imbalance Opportunity Cost'* by adjusting the systematic bias (or hedge) with which it enters imbalance prior to Gate Closure (see Section 2.5 for further details) under expected average conditions. The updated party positions are fed back into the core COM to see the combined impact on NIV and cash-out prices for the system as a whole. Changes to expected average SBP / SSP at the system level as a result of the change in bias may then lead to further adjustments in bias, and hence the process is repeated until a broad equilibrium is reached – i.e. parties cannot further improve their position given: their own position, other parties' positions and the overall expected system values from cash-out as a result of these.

Finally, the impact of potential new Long Term (LT) investments (improved balancing accuracy or new capacity) are overlaid onto the final positions from the ST response via a number of discrete scenarios, and re-run through the COM to understand the impact on cash-out prices and the wider system. The MIP regression model is used to infer the level of capacity that could

[16] Previous academic work (Bunn D, Karakatsani N (2008) Intra-day and regime-switching dynamics in electricity price formation, Energy Economics 30 (2008) 1776–1797) estimated a statistically significant relationship between cash-out prices and MIP. For this study a set of monthly regression models was estimated from historic data to determine the relationship between the dependent MIP variable and key independent explanatory variables (SBP, SSP, demand, reserve margin, wind, gas prices and carbon prices). The coefficients in the regression model were assumed to remain constant over time.

potentially be supported by the price signal flowing from cash-out into the energy market (see Section 2.6 for further details).

Figure 2 Overview of COM



It is important to note that the model does not produce an overall estimate of BSUoS costs as it is focused on 'energy balancing' only, rather than the costs of energy and 'system balancing' actions (e.g. to resolve transmission constraints). NIV cost (sometimes referred to as 'Energy CSOBM') is calculated to represent changes to the total energy balancing costs in each simulated settlement period.

Party types

The COM models the imbalance performance of BSC parties and their ST response to changing cash-out exposure. In the historic data sourced from Elexon (half-hourly imbalance volumes and party cash-flows for the post-P217A period from 5 November 2009 to end of 2012) there exist almost 200 individual BSC parties. Many of these have both active production and consumption accounts and some entities may hold a number of different party accounts, e.g. reflecting a number of different legal operating entities within a single VIU.

The historic data was used to create distributions of imbalance performance scalars, which were used as part of the Monte Carlo simulations[17] to simulate future imbalance as underlying parameters (e.g. wind volumes, demand volumes, etc.) change over time. However, to make the model manageable it was necessary to group the full set of BSC parties into a set of 'party types', these reflect either:

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[17] Correlations in imbalance across parties are estimated from historic data and factored into the simulated balancing accuracy.

- A large, clearly identifiable entity (which may be spread across multiple accounts) as its imbalance performance and behaviour to-date will be a function of its overall portfolio, and
- Discrete individual parties that share a similar set of underlying characteristics or plant mix, and which can reasonably be assumed to behave in similar manner

As a result the following parties were modelled directly in the COM:

- VIUs
    - Centrica, EDF, EON, RWE, SP, SSE
- Independent thermal generators
    - Drax, Intergen, GDF Suez, other independent dispatchable generators
- Independent wind generators
- Independent energy suppliers
- Others (e.g. non-physical traders)

2.4. Energy Balancing Cost Curves (EBCCs)

2.4.1. Overview

EBCCs are used in the Cash-Out Model (COM) to calculate the costs of energy balancing for the system under a given NIV in each half-hourly settlement period. They reflect the stack of possible energy only offers or bids. Where the simulated NIV value intercepts with the simulated EBCC, the relevant cash-out price is calculated from the volume-weighted average costs of actions up to the level of PAR or NIV value (whichever is lesser).

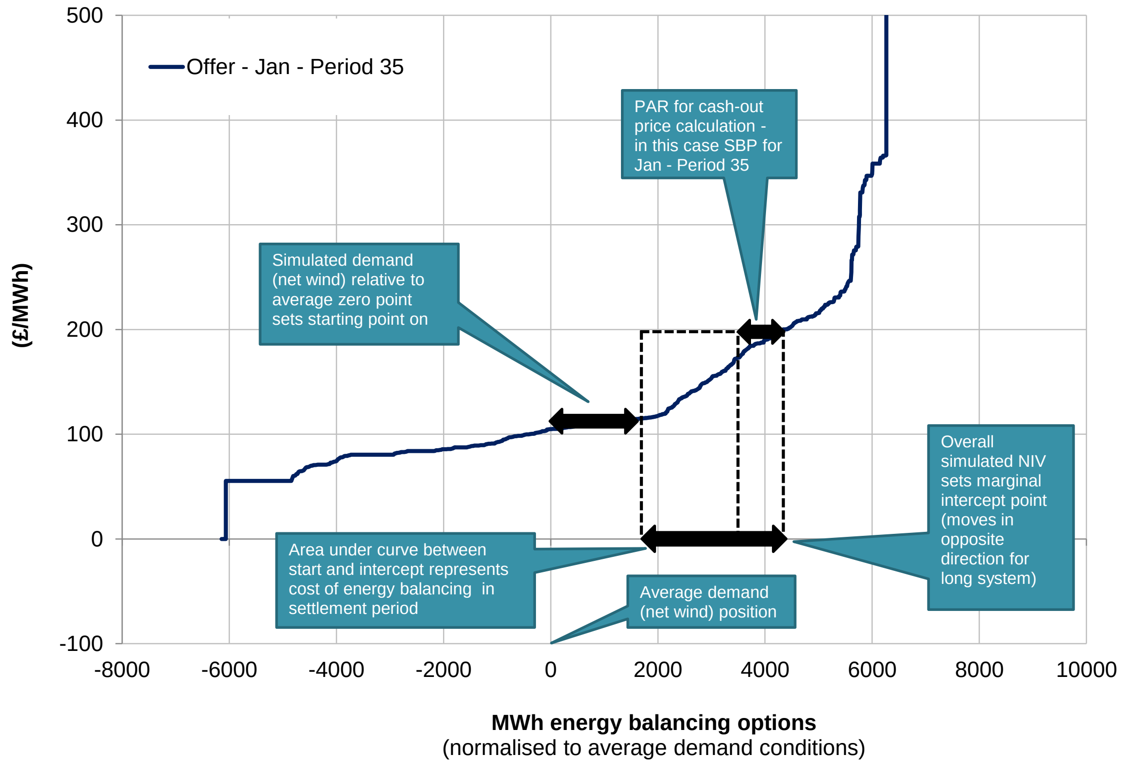
One ***base*** EBCC was constructed for each half-hourly settlement period in each characteristic month, with a separate curve for offers (buy side to resolve a short energy imbalance) and bids (sell side to resolve a long energy imbalance). To form the EBCCs, we took the full set of historic half-hourly BOA settlement data (for dates post-P217A implementation[18]) at BMU-level. We then assessed the structure of individual accepted BOAs taking into account the flagging and tagging rules to remove system balancing actions. Specifically, all Second Stage[19] flagged actions or actions with a de minimis tagged volume greater than zero were excluded. These represent actions that were either SO actions, emergency actions, CADL flagged or volumes too small for consideration.

By considering the parameters of the individual BMUs (efficiency, fuel type, typical price mark-up or mark-down relative to SRMC that they apply in the BM)[20] that form the accepted BOA stack and the wider system conditions at the time (e.g. NIV, commodity prices, demand, wind) we were able to create a "*normalised*" EBCC that reflects the stack of possible offers/bids centred around historic average demand/wind conditions. The stacks could then be adjusted reflecting changes in underlying demand and wind conditions.

[18] 5/11/2009 onwards, which is assumed to reflect fully unpolluted energy only stacks.
[19] System balancing actions which become unpriced.
[20] See Section 3.3 for the source of these assumptions.

Each individual step on the curve is a composite of the BMUs that were accepted under similar conditions at similar prices. The steps on the **base** EBCC also identify the use of reserve actions (BSAAs, BM-STOR, non-BM-STOR) and their respective volumes / price so that their impact on cash-out prices can be adjusted under the alternative RSP policy consideration (see Section 2.4.4).

Figure 3 Examples of a base EBCC offer stack for January 2012 settlement period



In the COM a number of adjustments are made to the **base** EBCCs as part of each individual simulation:

- Only the offer or bid curve is used depending on whether the system NIV is positive or negative for that simulated settlement period.
- The base curves are normalised around a zero point which reflects average demand (net of wind) conditions. Where simulated demand is greater than average and the system is short, the starting point on the EBCCs is shifted to the right to reflect the fact that fewer low cost balancing actions would now be available, all else being equal, as more demand now needs to be met in the wholesale market; the reverse is true when simulated demand is lower than average.
- As each step on the EBCC reflects a composite of individual BMU parameters, the prices offered or bid are updated to reflect outturn commodity and carbon prices from that individual simulation, i.e. if commodity prices are higher than average the overall curve will shift upwards; in addition the merit order of individual steps may also change depending on the relative movements of the SRMCs of different plant types.

2.4.2. Impact of changing capacity mix over time on COM / EBCCs

The base EBCCs reflect the capacity mix and composition of BMUs in 2012. Moving forward an exogenous assumption of the underlying electricity capacity mix to 2030 is a key input to the COM and affects a number of areas of the model:

- The increasing level of intermittent generation, particularly wind, will affect both the overall level of NIV, as well as the available energy balancing options in the base EBCCs in a given settlement period
- The capacity mix will also affect the available options (actions available to resolve the modelled NIV) in the EBCCs themselves in terms of:
    - Retirements – as the base EBCCs are constructed from an understanding of the individual BMUs we phased out oil, coal and gas plant that are retired as a result of the LCPD / IED, or because they are no longer economic (as determined by the underlying capacity mix scenario)
    - Additional actions in the EBCCs available due to new capacity available either from the exogenous capacity mix assumptions or added as part of the LT response (see Section 2.6)

For new capacity, the volumes and prices that are offered into the BM (e.g. offer mark-up above SRMC) are generally determined based on the historic analysis of BMUs, i.e. reflective of the historic bidding strategy for similar plant types[21].

However, for some new plant specific assumptions needed to be made regarding participation in the BM, in particular, new capacity for which historic analysis is less appropriate (e.g. demand side response) and those plant whose bids are influenced by subsidies (RO / CfD). In the case of the latter, it was assumed that plant will explicitly factor in the opportunity cost of their subsidy into their bidding strategy[22]. This leads to the potential for more negative SSP pricing in future, particularly from low carbon generators.

The composition of the EBCCs going forward is clearly a critical determinant of cash-out prices and a number of different capacity mixes were explored as part of the sensitivity analysis (see Section 2.10).

2.4.3. Unserved Energy

The length of the base EBCC offer curve is finite. Under conditions of high demand (net of wind) and with a particularly short system (i.e. high positive NIV) it is exceed the right-hand side of the curve. In reality, this would represent a system experiencing demand control actions.

As the model represents a top-down simulation of cash-out and does not model the bottom-up dispatch of plant it is necessary to calibrate the average level of Expected Energy Unserved (EEU) across the simulations for each spot year - i.e. the EEU is an input to, rather than an output from

[21] To do this we have restricted the analysis of markups / volume to existing plant which have at least 15+ years lifetime remaining, as a proxy for the behavior of new plant

[22] This is assumed to be the cost of ROCs for those technologies which currently receive them (e.g. wind, biomass, etc.) and an estimate of CfD strike prices for other technologies such as CCS (Carbon Capture and Storage). This was due to uncertainty over likely strike prices at the time the modelling was undertaken.

the model. For this we used Ofgem's (2012) Capacity Assessment data[23] and contrasted the annual de-rated capacity margin implied by the exogenous capacity mix, with the level of EEU from the Capacity Assessment expected at the given margin. This is particularly important for policy packages with VoLL pricing. It should be noted that capacity margins themselves are based on scenario modelling from DECC's 2012 Capacity Market Impact Assessment – see Section 3.2 for further details rather than Ofgem's Capacity Assessment.

At the top of the EBCC there are three separate tranches of emergency balancing actions, of increasing price which are used when demand is greater than level of available conventional balancing actions:

- A tranche representing Voltage Control (assumed to be 5% of demand)[24], which we count towards EEU
- A tranche representing emergency MaxGen options, based on current National Grid data[25], but which does not count towards EEU, and
- Any volume beyond this reflects load disconnection and is also counted towards total EEU

2.4.4. The Reserve Scarcity Price Function (RSP)

Under each of the policy packages all BM-STOR and non-BM-STOR actions in the EBCCs are subject to the Reserve Scarcity Price Function (RSP) as a determinant for the replacement price. Concurrent simulations of demand, wind and available plant capacity on the system are used to determine an operating reserve margin for each half-hour period. This reserve margin is an input to the RSP (Figure 1), which determines whether or not a replacement price is applied for STOR actions. Where the replacement price from the RSP is less than the utilisation price offered by the STOR actions (in the case of high reserve margin periods), then the utilisation price for this action is retained resulting in no change to the curve. Conversely, where the replacement price from the RSP is greater than the utilisation price offered by the STOR actions (in the case of tight reserve margin periods), then the RSP price replaces the initial price for this action.

In the model, the application of the replacement price occurs before the offers in the EBCC are sorted into a merit order according to increasing price. This means that in periods with tight simulated reserve margins, many of the STOR actions with very high replacement prices will be sorted toward the top of the merit order so may fall outside of the PAR range and not influence

[23]The 2012 Capacity Assessment (CA) was used as at the time of model development, 2013 data was not yet available – http://www.ofgem.gov.uk/Markets/WhlMkts/monitoring-energy-security/elec-capacity-assessment/Documents1/Electricity%20Capacity%20Assessment%202012.pdf.
EEU data was taken from the CA rather than the DDM scenarios provided by DECC, as the CA provides the relationship between total EEU and annual de-rated capacity margin, which is needed for calibration of the COM. The CA only looks forward over the relatively near term (2017). However, we have had to assume that the relationship between EEU and margin holds over time with the changing underlying capacity mix as it was not possible to obtain new bespoke CA analysis in the time available for this project.
[24] This is consistent with the National Grid Operating Code – http://www.nationalgrid.com/NR/rdonlyres/33623B15-D351-4489-9BF9-11AF8E921BA5/55761/13_OPERATING_CODE_6_I5R0.pdf
[25]These are generally provided by coal plant and their volume is reduced over time as the underlying BMUs which provide this service are retired, in line with the underlying capacity mix scenario

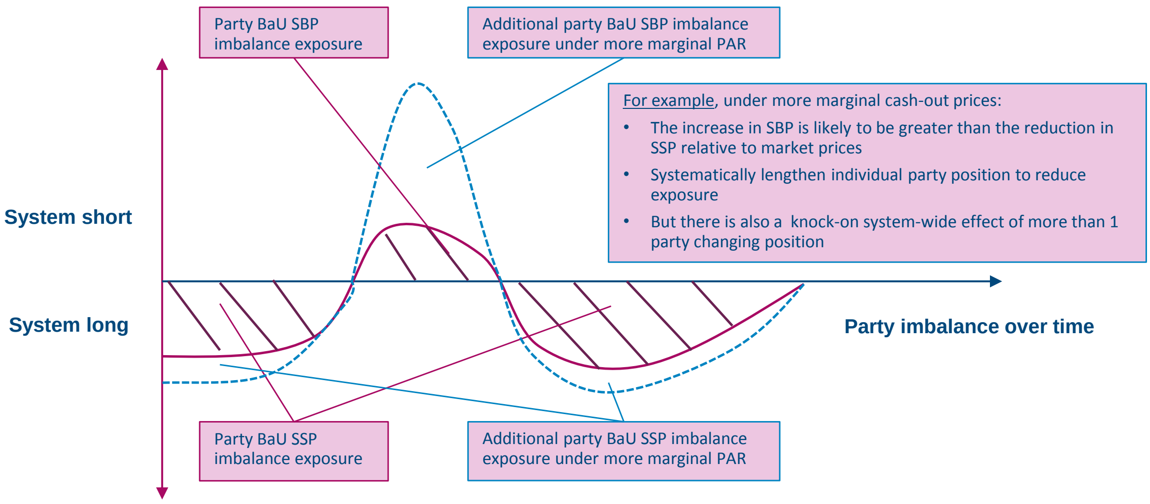
the SBP. This approach is intended to account indirectly for the fact there will be periods in which highly priced replacement price STOR actions are not included in the PAR range due to NIV tagging (which is otherwise not modelled). Typically in tight periods with large NIV the replacement priced STOR actions are captured within the cash-out price calculation, whereas in tight periods with small NIV they are typically 'NIV tagged out'.

Note that the RSP does not affect the calculation of energy balancing costs (NIV costs) as incurred by the SO.

2.5. Short Term (ST) response

All the changes proposed under the policy packages will affect the exposure that parties have to cash-out (Figure 4). In the short term it is assumed that the only tool available to parties to reduce a change in this cash-out price exposure is through systematically lengthening (or shortening) the bias (or hedge) in their positions as they enter Gate Closure.

Figure 4 Illustration of imbalance exposure under more marginal PAR over a discrete time period



It is assumed that parties carry this systematic bias into the settlement period as an efficient mitigation of imbalance risk, and in particular due to the asymmetric risk between the SBP and SSP[26]. Systematic bias by party type is calibrated against historic data as a starting input assumption. However, any change in systematic bias across a number of parties in response to changing conditions will have knock-on system level impacts. For example, if all parties go longer this will reduce the occurrence of a short system and on average depress SBPs, which could then have affected their decision to go longer in the first place.

The ST response function in the model attempts to understand the equilibrium[27] response for the system as a whole across all parties, for each characteristic day in each spot year. It does this by trying to minimise parties' Imbalance Opportunity Cost (OC) by adjusting their systematic

[26] At present the spread between SBP and MIP is typically greater than the spread between MIP and SSP, as the costs of balancing a short system are typically greater than those to balance a long system.
[27] Prices will respond to the aggregate position taken by all parties such that individual parties need to consider not only their own response but also the response of other parties.

bias for the day as a whole[28]. We use the term OC here to represent the loss to a party that is incurred by being out of balance, rather than settling its entire position in the wholesale energy market:

- For instance, under dual pricing policies, a short party in a short system will have to procure energy through cash-out at a price equal to SBP. This price is typically greater than the price at which this energy could have been procured ahead of Gate Closure, which for the analysis we assume is equivalent to the MIP. Hence the OC for this particular settlement period is the difference between the SBP and MIP.
- Likewise, for long positions in a long system, the price received for spilling energy (SSP) is less than what could have been received had the position been settled in its entirety in the wholesale energy market (again, assumed to be at MIP). Hence the OC in this case is the difference between the MIP and the SSP.

At present, because the spread between SBP and MIP is typically larger than the spread between SSP and MIP (i.e. the costs of balancing a short system are systematically higher than balancing a long system) parties 'tend' to enter imbalance slightly long on average as this helps to minimise the effective OC.

For each characteristic day (one per month across each spot year) the COM first runs a set of 100 Monte Carlo simulations[29]. Each individual simulation generates system level results for cash-out prices, NIV, MIP as well as party level values for imbalance volumes, CEV (Credited Energy Volumes), BCV (Bilateral Contract Volumes) and the resulting party cash flows, for each settlement period of the day.

From the distribution of simulation results the average values are stored. An optimisation is then undertaken, which aims to minimise the parties OCs under average expected conditions across the characteristic day, by changing their daily position bias. The optimisation is dynamic in that as parties change their bias this impacts on their individual imbalance volumes, and overall system NIV, MIP and cash-out prices.

The final bias values represent the optimised equilibrium position under *expected average conditions*. However, using these new party bias values as an input to the original set of Monte Carlo simulations may lead to slightly different average system values, and hence a different ST response. The process of Monte Carlo simulations, followed by ST response and new Monte Carlo simulations with updated bias values is repeated several times until equilibrium is reached. This occurs where there is no further change in bias position or average system values. This convergence is relatively quick, typically only requiring 2 or 3 iterations.

The updated bias positions also reflect a shift of volume from cash-out to the energy market or vice versa. As a result the starting intercept point on the EBCCs for the next set of Monte Carlo simulations is adjusted by this volume. For example, if changing bias leads to parties going longer overall in the BM this implies that more energy is now being contracted in the wholesale energy market. As a result fewer offers will be available for balancing in the BM and so the

[28]This assumption was discussed with the EBSCR TWG and deemed more appropriate than a bias strategy which evolves either within-day or is fixed annually.

[29] Simulated variables in the Monte Carlo runs are individual party imbalance for each production and consumption account, demand shift and stretch parameters, wind output, overall plant availability for thermal plant and commodity prices (gas, oil, coal, biomass, and carbon).

intercept point on the buy side EBCC starts further to the right to reflect a more expensive set of remaining balancing options. This means that the overall ST response can lead to two opposing effects, the direct impact on NIV of parties being shorter or longer overall in the BM, and more or less volume being available for energy balancing.

The final output following the ST response model is a complete set of cash-out prices and cashflows generated using the optimised position bias for parties for a particular policy and underlying capacity mix.

2.6. Long-Term (LT) response

Over the Long-Term (LT) it is assumed that parties can manage their imbalance exposure by doing more than adjusting their systematic bias, by making additional investments. These options were explored by testing a number of discrete scenarios on top of the final ST results. LT investment options are separated into two groups:

- Those where a rational decision would be made comparing investment costs directly to the expected saving in imbalance costs, such as improvements in demand / wind forecasting or plant reliability (see Section 4.3.4).
- Those which are dependent on rational investors building new capacity (or extending the life of existing capacity) as a result of longer term electricity price signals driven by changes to cash-out.

The latter is more complex to understand and illustrate through the modelling approach, as decisions around investment will in reality be influenced not only by changes to cash-out prices and their subsequent impact on near term market prices and forward prices, but also by a number of other factors external to the model, most notably the introduction of the CM.

As the focus of the modelling is on the impact of cash-out reform the approach taken here does not capture all the factors which could potentially feed into a decision to invest in additional capacity. Due to this, we have tested the extent to which different levels of investment in new capacity could be considered *'broadly rational'* given the underlying capacity mix on the system and the impact this new investment will then have on cash-out.

The starting point for this is the regression model, which forms part of the core COM, to understand the relationship between changing cash-out prices and within day market prices (i.e. the MIP). Separate analysis undertaken for DECC identified a clear relationship between near term market prices and forward prices[30]. Hence, it is a reasonable assumption that the impact of cash-out prices on MIP will ultimately flow through into forward prices, which in turn could provide the signal for new investment.

Within the COM we:

- First compare the difference in average MIP for a given spot year under DN (after the ST response) and from a policy package (again after the ST response). Where the MIP

[30] The analysis sought to test for a consistent premium or discount in forward power prices relative to spot power prices for corresponding delivery periods and accounted for forecast error relating to the factors that drive spot electricity prices. One of the findings of that analysis was that, for the majority of forward power contracts in the period studied, the ratio of forward prices to the corresponding spot prices was a function of a constant factor that was statistically significant at the 95% confidence level.

under the policy package is higher than DN this represents the potential investment signal driven by the changes from cash-out alone.

- As the regression model contains reserve margin as one of its independent variables it is used to infer the maximum amount of capacity (not technology specific) to add back into the COM. The Monte Carlo simulations are then re-run to test the drop in MIP (and wider impact on cash-out prices) with this new capacity in the model.
    - If after the new capacity is added, as long as MIP is not below that DN case then we infer that this capacity could be supported by the price signal from cash-out changes, subject to the wider caveats about whether this capacity would materialise in practice
    - If the MIP drops below that seen under DN, we re-run a variant of the scenario with a smaller proportion of the maximum capacity[31]
- The impact of new capacity in the COM depresses the MIP in a number of ways:
    - By increasing the reserve margin directly in the MIP regression model (i.e. a higher margin will lead to smaller MIP all else being equal)
    - By adding, generally cheaper, available energy balancing options to the EBCC stack, which reduces cash-out prices and the MIP via the regression model. Similarly, new capacity increases the margin seen by the RSP, which in turn reduces cash-out prices and MIP.
    - By reducing the level of annual EEU, which reduces cash-out prices when VOLL costing is applied. As described in Section 2.4.3, the overall level of EEU is calibrated against Ofgem's Capacity Assessment based on the de-rated capacity margin for the year. Adding new capacity under the LT response will therefore reduce the level of EEU as an increase in system capacity will also increase the de-rated capacity for which EEU is determined.

Over the time period assessed by the study, changes to the underlying capacity mix (which are an exogenous input to the COM) will have a significant impact on the difference in MIP between DN and the potential cash-out policy packages, and hence the incentive to invest in new capacity from cash-out reform alone. As a result, a number of capacity mix sensitivities were explored (described in more detail in Section 2.10), which include:

- Core: a bespoke DECC scenario to 2030 (from its Dynamic Dispatch Model) which does not include the effect of the CM. This scenario was selected by Ofgem as the core scenario given the time frame for introduction of the CM and the desire to contrast the impact of cash-out reform under scenarios both with and without the impact of the CM on the future capacity mix (see Section 3.2 for details). Ofgem's Capacity Assessment (2012) central scenario was not used given the shorter time horizon for that modelling.
- CM: DECC's latest EMR central scenario, which does include the CM.
- Alternative: National Grid's 2012 Gone Green scenario.

[31] For practical reasons the scenarios considered are 100%, 2/3 and 1/3 of the implied maximum capacity addition

2.7. System Operator (SO) response

Within the COM the costs of directly SO procured and 'actioned' reserve or balancing services are captured by:

- The BPA/SPAs (covering BM / non-BM STOR availability fees, BM Start-up) applied to specific settlement periods and using historic values and allocation (relevant only to the DN case since BPAs/SPAs are replaced by the RSP in the policy packages), and
- BM STOR utilisation feees, which are captured within the base EBCCs[32], as they are constructed from historic actions (i.e. accepted offers) which contain this data

The amount of reserve contracted by the SO and its use in future may change as a result of:

- Increasing levels of intermittent generation, demand changes, new interconnection and changes to the largest in-feed loss, and
- The level of 'self-provision' of reserve by market participants

The COM is designed to assess how cash-out prices change under different policy packages and how party types respond to this in the short-term by changing their degree of bias, or in the long term as a result of new investment, which in turn would affect the level of SO reserve requirement. However, it is extremely complex to estimate what the optimum economic provision of SO reserve would be and this is not endogenous within the COM.

Based on a number of discussions with National Grid it was assumed that the SO's behaviour under all policy packages would remain broadly the same as today, in terms of the proportion of use of SO contracted reserve versus energy balancing actions in the BM. However, the overall volume of reserve required will rise in line with changes to the wider system from increasing wind, demand and largest potential infeed loss.

To mimic this within the model the initial price of identified historic reserve actions in the EBCCs was adjusted such that they retain their relative position in the merit order of balancing actions over time. In addition the overall volume of reserve in the curve is scaled according to the rising reserve requirements (which are scenario specific).

2.8. Approach to modelling individual policy considerations

Individual cash-out reform considerations are captured in the COM as follows:

- *Marginality of price* – this is undertaken by changing the PAR calculations in the COM – i.e. the degree of averaging across accepted bids or offers (reflected in the EBCCs) when calculating the SSP or SBP respectively
- *Single / dual price* - by default the COM is set to dual pricing. Under a single price all parties pay the SBP when the system is short regardless of whether their imbalances are short or long versus the contracted position, and vice versa for SSP when the system is long[33]

[32] We were provided additional data by Elexon and National Grid within the BOAs to identify these directly so that they could be incorporated into the EBCCs

[33] We assume that parties do not actively try to chase the NIV under a single price to gain from being in the opposite direction to the system, but only respond via the average change in their daily hedge position when entering imbalance settlement.

- *Uncosted demand control actions* – the COM reflects two tranches of potential demand control acitons, Voltage Control within the main EBCC stack and load disconnection (when the NIV exceeds the top of the EBCC). By default these are costed at zero, but under VoLL pricing they have replacement prices which feed into the SBP[34].
  - Note that for load disconnection the repriced volume is captured as part of the standard PAR calculation rather than the price automatically hitting VoLL as soon as any load disconnection occurs, i.e. if PAR is 500 MWh and there is only 1 MWh of load disconnection only 1 MWh of VOLL pricing would enter the PAR calculation and the cash-out price.
- *Allocation of reserve costs* – by default reserve utilisation in the COM reflects prices seen from historic data (reserve actions are identified within the EBCC stack) with reserve availability fees added to the calculated cash-out prices via the BPA/SPAs.
  - Under the RSP the BPA/SPAs are removed as all reserve costs (including non-BM STOR utilisation which is not currently included in cash-out) are now covered by the scarcity replacement pricing
  - The base utilisation price of the reserve actions in the EBCCs are replaced with the value from the scarcity price function calculated for that particular settlement period, only in instances where the replacement price is greater than the initial offer price submitted. The reserve actions are then resorted in the merit order based on their new scarcity price and factored into the cash-out price calculation when they form part of the PAR value

2.9. Implicit modelling assumptions

Table 5 below illustrates our high-level assumptions for this analysis. Modelling these impacts quantitatively is inherently difficult and given the time and resources available for this project we aimed at making simplifications only where necessary.

The impact of cash-out reform on interconnector flows is a potentially important in relation to security of supply and costs of balancing. However, it is extremely complicated to model interconnected markets alongside a detailed representation of the BM, to understand how flows may change under different policy package. Quantitatively assessing this was not within the scope of the project and hence a representation of interconnectors is not currently included in the COM. These issues are discussed qualitatively later in the report and an illustration of the potential impact has been added to the CBA in Section 5.3.1.

[34] Voltage Control has been costed at £6000/MWh, Load disconnection in the core-No-CM scenario has been costed at £17000/MWh and in the with-CM sensitivity at £6000/MWh.

Table 5 Implicit modelling assumptions

Assumption	Implications
P217A and other tagging/flagging rules successfully removed all 'non-energy pollution' such that the modelling is focused on energy balancing.	Any residual 'pollution' in cash-out prices could affect the results.
The approach is focused on modelling energy only actions in the Balancing Mechanism, with the relationship to the wholesale market captured indirectly via a regression model of the MIP.	Not modelling the wider electricity market and corresponding dispatch explicitly.
The current relationship between cash-out prices (and other system parameters such as reserve margin) and the MIP as estimated by the regression model holds in future. (See Appendix A for further details)	This may not accurately capture the changing relationship under different policy packages or significant differences in the wider electricity system; however, this is likely to be the best approximation possible given the available historic data.
The future bidding strategies with respect to volumes bid/offered and the price mark-downs/mark-ups of BM participants will broadly reflect those calibrated from historic behaviour.	The volume of offers and bids and the mark-ups in BM offer and bid prices will remain the same despite changing capacity mix and portfolios of different players. This also assumes that the introduction of the CM will not change bidding behaviour. This assumption was necessary as there is no allocation of individual BMUs to parties in the model and therefore no basis for evolving strategies. Changed strategies would primarily affect the cost of system balancing.
Parties respond rationally to reduce their expected imbalance exposure, by adjusting the bias in their position when entering imbalance in the short term or by investing in new capacity as a result of potential signals driven by changes to cash-out.	An equilibrium is reached assuming economically rational behaviour.
Simulated changes in behaviour of parties (e.g. in position bias) are not mapped back to the level of individual plant and so do not reflect changes in dispatch fundamentals.	This may ignore second order effects such as lower efficiency of part loaded plant and hence some additional costs of changes to behaviour.
The optimal level of System Operator (SO) procured and 'actioned' reserve is not calculated internally within the model.	Estimates of baseline changes to SO reserve provision are entered as external assumptions into the modelling approach based on discussions with National Grid. The endogenous analysis is focused on the response of BM participants given the available level of SO reserve, and other factors.
The impact of new LT investment in *Iteration 3* has no impact on the results of *Iteration 2* – i.e. no further ST response in systematic bias.	This is a simplification to aid transparency in the understanding of *Iteration 3* versus *Iteration 2* results. In reality, new investment will impact on system level cash-out prices and may impact on any response in systematic bias.
Wider issues affecting cash-out such as changes to cross-border balancing and interconnector flows are not calculated within the model.	The possible impact of these is addressed qualitatively.

Assumption	Implications
As we do not model fundamental dispatch changes in the energy market it is difficult to infer anything directly about operational security of supply, however, investment in new capacity will affect overall capacity adequacy.	EEU in the model is calibrated to Ofgem's 2012 Capacity Assessment outturn for a given annual de-rated margin (based on the assumed capacity mix to 2030 which is an input to the modelling). New capacity investment will increase de-rated margins and lower EEU.
The share of the demand and generation market by party types are assumed to remain at their historic shares over time, with the exception of independent wind whose percentage share is assumed to be constant but total output grows with growing wind capacity. As a result, the generation shares for other parties are scaled back accordingly.	The share of independent suppliers as a % of the market relative to the VIUs does not change over time.

2.10. Sensitivity analysis

A number of sensitivities were modelled to assess the consequences of alternative capacity mix trajectories, how robust the results are to party imbalance correlation assumptions and the individual impacts of the RSP. Specifically:

- The core scenario capacity mix and unserved energy assumptions are based on DECC assumptions for a market without the CM. Given concurrent discussions under Electricity Market Reform (EMR), testing the assumed capacity mix and unserved energy in a market with the Capacity Mechanism was necessary. Differences in the capacity mix and EEU assumptions between a with and without Capacity Mechanism case are most significant in 2030 as highlighted by Figure 5. (Capacity Mechanism sensitivity results are denoted by CM.)
- We also modelled a capacity mix and unserved energy assumptions according to National Grid's 2012 'Gone Green' scenario trajectory. This scenario is characterised by much larger volumes of wind on the system and higher levels of unserved energy in interim years. (The Gone Green sensitivity results are denoted by GG.)
- The core modelling runs contain two independent wind parties with identical properties, and equal output volumes. The correlation between their production imbalance deviations is assumed to be to zero. We also modelled a sensitivity that assumes forecast errors of these two wind parties are perfectly correlated to demonstrate the impact on wind generators of being out of balance consistently in the same direction as the system (thus reducing the benefit of single pricing). (This sensitivity is denoted 1wind.)
- Understanding the individual impact of the RSP is also important, so sensitivity model runs were made to packages without the application of this policy. (This sensitivity is denoted noRSP.)

The sensitivity runs undertaken are summarised in Table 6 below.

Table 6 Sensitivity analysis model runs

Sensitivity	Years	Packages	Purpose
Capacity Mechanism CM	2030	DN P3 P5	To test the effect of the DECC Capacity Mechanism capacity mix and unserved energy assumptions
Gone Green GG	2020 2030	DN P3 P5	To test the effect of the National Grid Gone Green capacity mix and unserved energy assumptions
100% wind correlation 1wind	2030	DN P5	To understand the impact of independent wind production forecast error correlation assumptions
No RSP noRSP	2020 2030	P5	To understand the individual impact of the RSP

3. KEY DATA ASSUMPTIONS

3.1. Energy Balancing Cost Curves (EBCCs)

The Energy Balancing Cost Curves (EBCCs) as described in Section 2.4 were generated using historic BOA stacks provided by Elexon. Individual Balancing Mechanism Unit (BMU) properties were based on Baringa assumptions.

Table 7 Key EBCC assumptions use and source

Item	Resolution	Use	Source
Bid/offer acceptance stacks	Period	Used to generate EBCCs that dynamically update with changes to prevailing commodity prices	Historic data provided by Elexon
BMU level assumptions for current fleet: fuel, heat rate, carbon emissions, VOM, base retirement year, capacity	Fixed		Baringa assumptions

3.2. Capacity mix and de-rated margins

The evolution of the underlying capacity mix affects the model in four ways:

1. Incumbent generators that exist in the EBCCs and due for retirement will no longer feature in the EBCCs past their retirement year. Thus the EBCCs in 2030 are comprised of fewer data points than were derived from the historic accepted bid/offer stack data set. All years modelled will have some level of retirement relative to historic data.
2. New build capacity is inserted into the EBCCs as single blocks by technology type. The volume and price strategies with which these generators submit bids/offers are based on the historic strategies for equivalent plant types.
3. The simulation of reserve margin used by the regression model and the RSP is dependent on the total volume of available capacity which is linked to the underlying capacity mix. Reserve margin refers to the short-term operational margin of the system in an individual half-hour period.
4. Implicit to the capacity mix (and demand forecast) assumptions is a corresponding de-rated margin, which determines the volume of EEU in any given year using the Capacity Assessment assumptions.

The source for all assumptions related to the evolution of the capacity mix and de-rated margins is found in Table 8. Importantly, any wind capacity on the system is exclusive of embedded wind as demand figures are assumed to be net of embedded sources of generation[35]. Any reserve

[35] Note that the commonly used term "demand net of wind" refers to network variables only; i.e.: all quoted demand values are net of embedded sources of generation and all quoted wind values are net of

actions that were historically taken by National Grid as BSAA, BM-STOR or non-BM-STOR generators are assumed to expand in volume in line with likely increases in the reserve requirements held by National Grid.

Table 8 Key capacity mix and de-rated margin assumptions use and source

Item	Resolution	Use	Source
Core plant capacity mix (excluding items below)	Annual	New plant capacity used to define new steps on EBCCs, retirement profile of existing plant used to remove capacity from base EBCCs in future years, overall capacity used as part of simulated plant availability which is an input to the reserve scarcity price function and MIP regression model	Bespoke DECC DDM modelling scenarios from 2012 CM Impact Assessment[36]
DSR capacity and various supporting assumptions			DECC (2012) Electricity System Analysis – future system benefits from selected DSR scenarios
Maxgen capacity and various supporting assumptions			National Grid[37]
Capacity de-rating factors		Used to assess annual level of EEU	Bespoke DECC DDM modelling scenarios
De-rated margin			
Relationship between de-rated margin and EEU			Ofgem (2012) Electricity Capacity Assessment
Embedded wind capacity projections		Used to adjust DECC total onshore wind capacity numbers as demands, etc. are all net of embedded generation	National Grid SYS (Seven Year Statement), 2010
Reserve parameters various	Period	Used to scale volume of BM/non-BM STOR actions within EBCC in line with increasing system requirement for reserve	Formula based on data from National Grid, Imperial College, DECC

The evolution of the capacity mix under the Core Scenario can be seen in Figure 5. The acronyms GG and CM refer to two sensitivities to the capacity mix modelled, Gone Green (2012)

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embedded wind. Thus "demand net of wind" refers to all network demand remaining following that which is satisfied by the level of network wind on the system.

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

[37] http://www.nationalgrid.com/uk/Electricity/Balancing/services/balanceserv/systemsecurity/maxgeneration/

and Capacity Mechanism Scenario respectively. Figure 6 indicates the change in de-rated capacity margin and implied EEU over time for the Core Scenario and sensitivities[38].

Figure 5 Evolution of capacity mix under different sensitivity scenarios

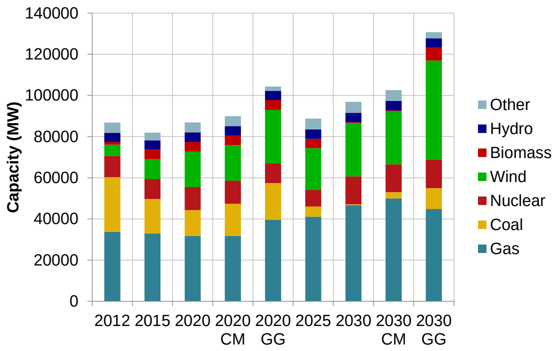
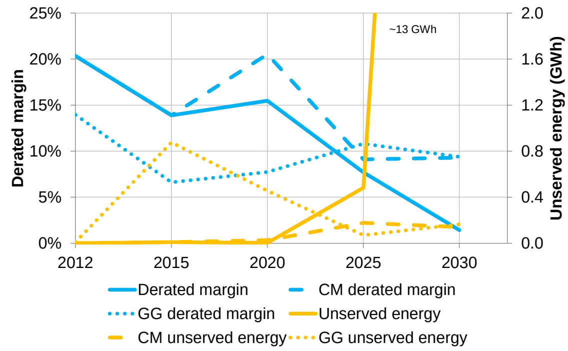


Figure 6 Evolution of de-rated capacity margins and annual unserved energy under different scenarios



3.3. Plant cost and strategies

The price at which capacity is bid or offered into the BM is dependent on three things:

1. The physical properties of the generators: efficiency/heat rate, carbon emissions, VOM and any subsidy (ROCs or CfD).
2. Prevailing commodity prices (discussed further in Section 3.6), which together with the above form the SRMC of the plant.
3. The mark-up strategy that a generator applies to its SRMC when making bids/offers in the Balancing Mechanism. For bids, this mark-up will be a discount to its SRMC; for offers it will be a premium to the SRMC.

The proportion of a generator's volume that it bids or offers into the Balancing Mechanism (as opposed to contracting in the wholesale energy markets) also varies considerably by plant type.

The sources for assumptions used to derive plant price and volume strategies are shown in Table 9.

Table 9 Key plant cost and strategy assumptions use and source

Item	Resolution	Use	Source
Efficiency of new plant	Annual	On GCV basis, used to calculate SRMC for new plant additions to inform offer/bid pricing	DECC (2012) Electricity Generation Costs
Base VOM (Variable Operating and Maintenance) costs of new		Used to calculate SRMC for new plant additions to inform offer/bid	

[38] As mentioned previously these capacity mixes are not the same as those for Ofgem's Capacity Assessment (2012 or 2013)

Item	Resolution	Use	Source
plant		pricing	
Emission factors		On GCV basis, used to calculate SRMC for new plant additions to inform offer/bid pricing	Defra (2012) greenhouse gas conversion factors for company reporting
ROCs per plant type		Used to calculate SRMC for new plant additions to inform offer/bid pricing	DECC (2012) Renewables Obligation Consultation
ROC price projections		Used to calculate SRMC for new plant additions to inform offer/bid pricing	Assumed to maintain current prices
CfD reference and strike prices		Used to calculate SRMC for new plant additions to inform offer/bid pricing	Bespoke DECC DDM modelling scenarios
Bid/offer strategy for coal, CCGT, peaking plant	Period	Used to inform price/volume offered into BM (i.e. EBCC) by equivalent new capacity additions	Estimated from analysis of historic BOA-level settlement data provided by Elexon
Bid/Offer DSR	Period	Used to inform price/volume offered into BM (i.e. EBCC) by equivalent new capacity additions	DECC (2012) Electricity System Analysis – future system benefits from selected DSR scenarios
Bid/Offer strategy for all other plant	Period	All other plants are assumed to bid/offer their entire volume at their SRMC	
Average BPA values by characteristic day and settlement period	Period	Adder to cash-out prices under DN	Historic data provided by Elexon
Transmission Loss Multiplier	Fixed	Adjustment to cash-out prices	Historic data provided by Elexon

3.4. Historic party shares

Historic market shares by party type were calculated at the monthly level based on the average seen in the historic settlement data provided by Elexon for the post-P217A period (from 5 November 2009 to end of 2012) and is consistent with the other historic data used to construct the EBCCs.

The shares were calculated for:

- % share of demand in energy market

- % share of overall generation in energy market
- % share of wind generation in energy market
- % share of accepted BM offers
- % share of accepted BM bids

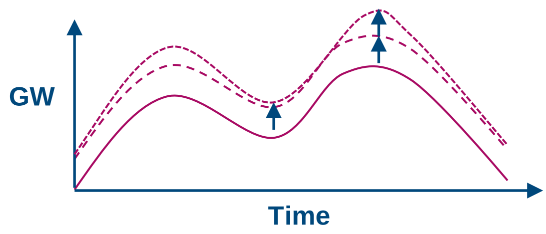
The % shares were held constant over time to avoid making additional assumptions about how the market structure might evolve over time. The only exception to this is that the historic % share of wind generation by parties was assumed to take priority over the % share of other generation types. Hence, as the overall volume of wind on the system grows the residual share of non-wind generation in total generation declines. Hence the % share of total generation by party type is maintained only for the residual generation after wind is accounted for.

3.5. Demand and wind

Projections of demand are used by the model to simulate the total growth in energy contracted either through wholesale energy markets or the BM. Demand is simulated on a half-hourly level and as such is characterised by a daily demand profile that varies by month. Over time, the uncertainty in the magnitude of demand in any given period is simulated using the combination of two parameters:

1. Using a shift parameter that shifts the entire demand profile across the day up or down. Conceptually, this parameter relates to systematic changes in demand due to lower macroeconomic growth or greater substitution to electric heating for example. The demand shift parameter is determined by taking a triangular distribution of demand sampling between DECC's low, central and high annual trajectories.
2. Using a stretch parameter that can accentuate or depress the shape of the daily profile (e.g. make peaks, spikier or troughs flatter). Conceptually, this parameter relates to intra-day variation in demand that may reasonably occur due to an unseasonably cold day for example. The stretch parameter was determined using historic distributions of demand around the average.

Figure 7 Simulated demand parameters



The simulation of outturn wind is treated in a similar way to demand except that the shift parameter is replaced by a total network wind capacity assumption. A wind variation parameter is used to simulate variations in wind speed and output that could be expected for this wind capacity. This variation is applied to a daily profile with half-hour resolution.

All sources for demand and wind data assumptions are outlined in Table 10. Note that all demand (and consumption accounts) quoted in the model are net of embedded sources of generation.

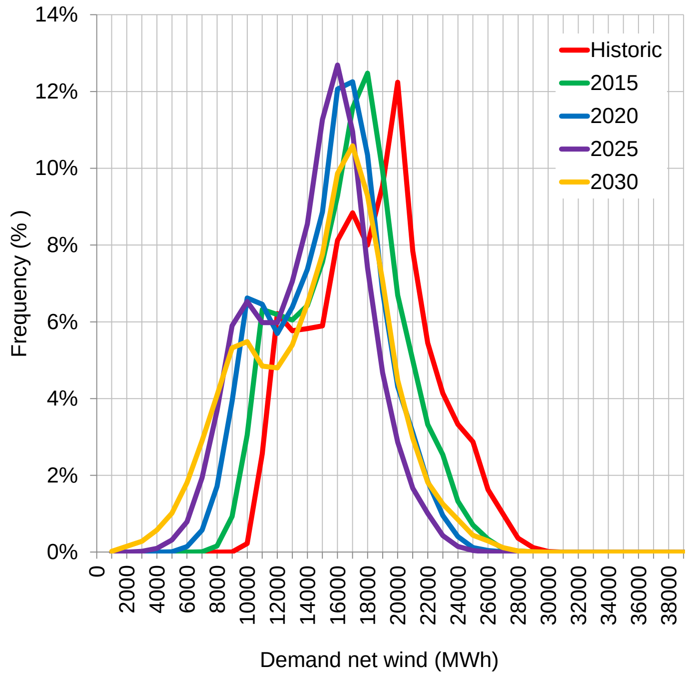
Table 10 Key demand and wind assumptions use and source

Item	Resolution	Use	Source
Annual energy demand projections	Annual	Used in simulation of energy demand	DECC UEP October 2012
Demand stretch distribution parameters	Monthly		National Grid[39]
Average demand profile shapes	Period	Combined with simulated demand shift and stretch parameters to create overall demand profile within each characteristic day, future changes to core demand profile estimated from DECC study	DECC (2012) Electricity System Analysis – future system benefits from selected DSR scenarios
Wind variation distribution parameters	Monthly	Used in simulation of wind output	DECC wind capacity mix applied to Baringa in-house simulated hourly load factor data[40]
Average wind profile shapes	Period	Combined with simulated wind output factor to create within day profile for each characteristic day	

The outcome of combining the evolution of demand with the substantial increases in wind capacity in the scenarios is that a reduction in demand net of wind over time is assumed (Figure 8).

[39] INDO http://www.nationalgrid.com/uk/electricity/data/demand+data/
[40] Based on hourly wind speed data from Anemos Wind Atlas.

Figure 8 Evolution of distribution of demand net of wind



3.6. Commodity prices

The evolution and distribution of commodity price changes is an important input to the model. Commodity prices are one of the input assumptions used to determine the SRMC of generators in the EBCCs. Historic mark-up strategies are then applied to these SRMCs to determine bid/offer prices that are used to form outturn cash-out prices.

Commodity prices are simulated at an annual level by creating triangular distributions around low, central and high price trajectory assumptions from the sources outlined in Table 11. In the case of gas, capturing seasonality effects was considered important, so monthly scalars are applied in the model that increase gas prices in winter months and reduce them in summer months.

Table 11 Key commodity price assumptions use and source

Item	Resolution	Use	Source
Fossil fuel price projections	Annual	Used in simulation of commodity prices	DECC UEP October 2012
DECC carbon price projections	Annual	Used in simulation of commodity prices, low values are bounded by Carbon Price Floor	DECC Carbon Valuation Oct 2012
Biomass prices	Annual	Used in simulation of commodity prices, historic price range maintained	E4Tech 2010 study for DECC

Item	Resolution	Use	Source
Seasonal gas price scalars	Monthly	Used to adjust simulated gas price data	In-house Baringa commodity price database

3.7. Imbalance deviation

Imbalance deviation represents the departure of a party's outturn position from its contracted position. The characteristics of this imbalance differ according to party types and account type (production/consumption). Two main drivers for imbalance were modelled – position bias, which is any systematic imbalance deviation that a party might adopt to hedge its cash-out price risk, and unanticipated imbalance – both of which used historic party-level data provided by Elexon to determine input assumptions (Table 12).

Table 12 Key imbalance data assumptions use and source

Item	Resolution	Use	Source
Position bias	Monthly Account	Used directly in the model to simulate party hedging strategies	Estimated from historic party-level half hourly settlement data provided by Elexon
Imbalance deviation distribution parameters		Used in the simulation of imbalance deviation scalars for each party	
Imbalance deviation correlations			

3.7.1. Position bias

A party's position bias (or hedging strategy) refers to its imbalance on account of a deliberate out of balance position adopted to mitigate its exposure to cash-out. The model applies position bias to a party's expected position to determine its bilateral contract volume. The final imbalance volume of a party is made in reference to its bilateral contract volume so will include any imbalance on account of position bias.

The historic average of imbalance for each party was taken as its position bias. This was determined on a monthly level and is fixed across years prior to any modelled ST response (see Section 2.5). Historically, in aggregate, parties have adopted long position bias strategies to mitigate exposure to asymmetric cash-out price spreads which have been greater on the buy side than the sell side of the market.

3.7.2. Unanticipated imbalance – distributions

A party's unanticipated imbalance refers to it incorrectly forecasting its position due to the physical characteristics of its account. For example, unexpected spikes in demand, the forced outage of thermal plants or unforecasted changes in wind output would all contribute to the unanticipated imbalance deviation of a party's account.

Figure 9 Distribution of consumption imbalance scalars, 2030

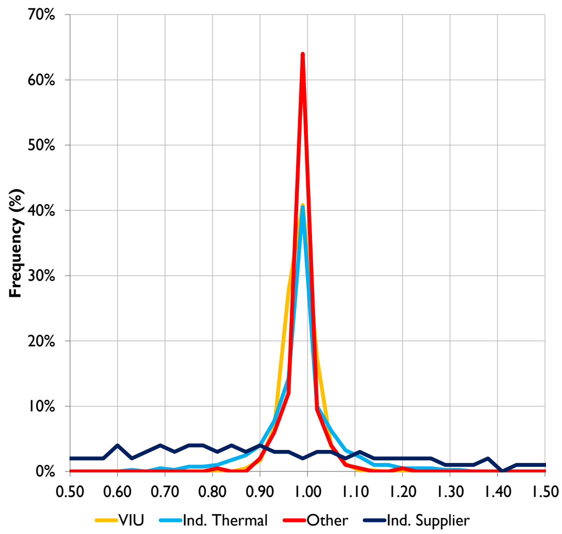
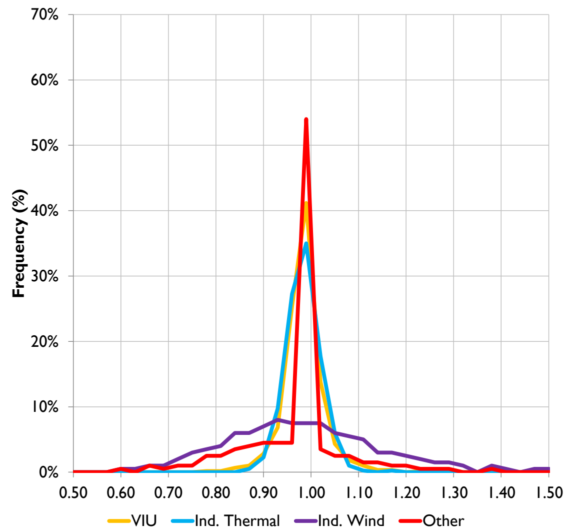


Figure 10 Distribution of production imbalance scalars, 2030



Where the position bias takes the average of a party's historic imbalance, unanticipated imbalance takes the historical distribution around this average to generate imbalance deviation scalars for model simulations. A separate imbalance deviation scalar is generated for each party account and for each Monte Carlo simulation. They are numbers that deviate either side of 1 at a frequency, direction and magnitude equivalent to historic deviations. Imbalance deviation scalars are applied to the expected position of a party such that a scalar of 1.1 would represent a 10% increase (long) in the outturn position of a party relative to its expectation. Taken with its position bias, a party's imbalance can therefore be determined. Figure 9 and Figure 10 indicate the distribution of imbalance deviation scalars for each party type and each account. Independent wind generators, for example, have historically been poorer at forecasting their position than VIUs, so have a broader distribution of production imbalance deviation. Importantly, parties with thermal assets are skewed slightly to the left (short imbalances) indicating their propensity for forced outages.

Another input used to generate the imbalance deviation scalars is the imbalance correlation between parties. For instance, imbalance may be on account of a systematic event that may affect all parties to some extent in the same period. Historic data was therefore used to determine any correlations between party's imbalances such that the generation of the simulated imbalance deviation scalars would represent this correlation. For example, if two parties have a positive correlation in their imbalance deviation then a long imbalance for one party will likely result in a simulated long imbalance for the other (depending on the magnitude of the correlation) and vice versa. The use of two identical independent wind parties with no correlation in their production imbalance deviation is a case in point (see Section 2.10 and Section 4.4.3 for further details).

It should be noted that the imbalance deviation scalars of parties are based on historic imbalances which will correspond to the historic account portfolio. These imbalances are carried forward through time despite changing capacity of individual parties. This assumption may understate the extent to which portfolio players are exposed to cash-out going forwards, for example, as changes in the capacity of wind in a portfolio would also result in changed imbalance distribution properties. However, this is the most neutral assumption as the alternative would require additional assumptions about the composition of individual parties' portfolios changes going forward, which are assumed to be maintained based on historic shares of generation / production / BM participation going forward (as discussed in Section 2.9).

3.8. Model calibration results

The model was first calibrated using a range of input data (e.g. demand, capacity mix, commodity prices) reflective of the post-P217A period (5 November 2009 to end 2012). Through careful construction of key elements of the model from detailed half-hourly historic settlement data it was possible to reproduce reasonably accurately historic NIVs, MIP and cash-out prices; both at an average level and in terms of the distribution of historic results. Figure 11 to Figure 14 below compare the historic and modelled distributions of these metrics.

Figure 11 Comparison of historic and modelled distribution of NIV

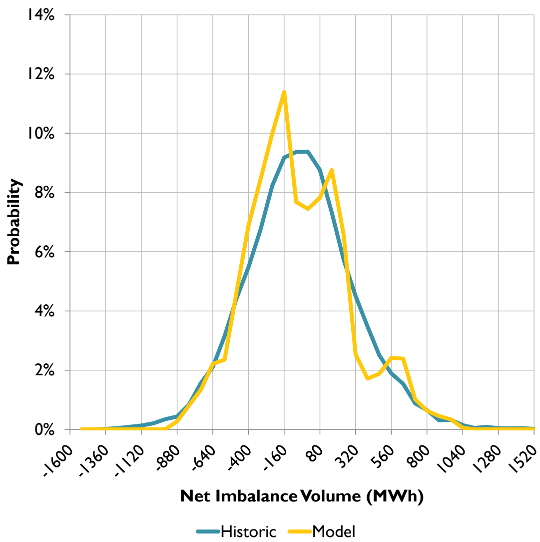


Figure 12 Comparison of historic and modelled distribution of MIP

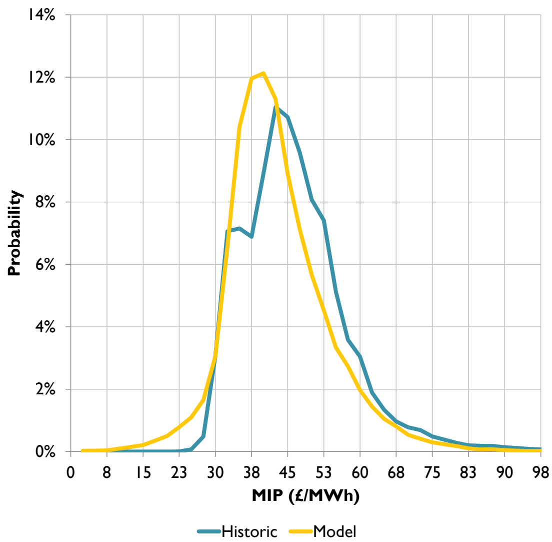


Figure 13 Comparison of historic and modelled distribution of SBP (main only)

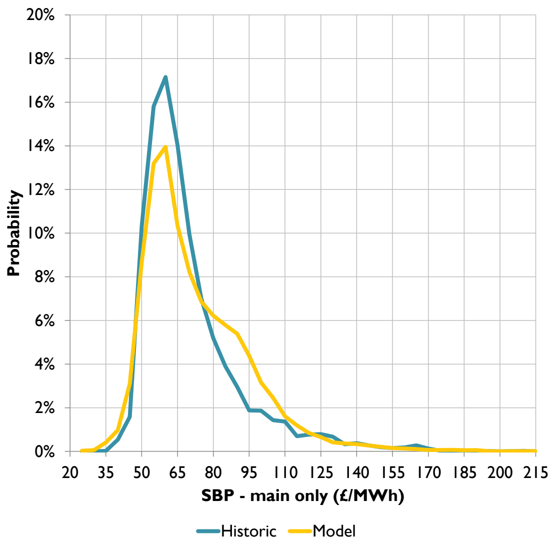
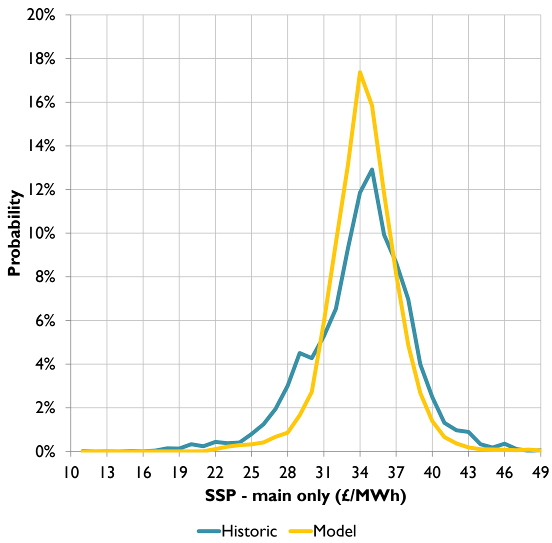


Figure 14 Comparison of historic and modelled distribution of SSP (main only)



4. DETAILED RESULTS

4.1. Historic analysis

Ofgem conducted analysis on historic data (dating back to the implementation of P217A – 5 November 2009) to understand the consequence of the policy packages in the absence of any behavioural response. This was undertaken by retrospectively applying updated PAR values, a single cash-out price, the RSP and VoLL costing to historic cash-out prices and cashflows according to each package's characteristics. The key results from this analysis are outlined in more detail in Ofgem's Impact Assessment, with the specific points summarised below.

This analysis demonstrates that the impact of lower PAR is greater on the buy side of the market than on the sell (Table 13[41]). In the case of average SBP, a substantial increase occurs when moving from PAR500 to PAR50, but with a corresponding smaller increase when moving from PAR50 to PAR1.

In the case of average SSP, a more marginal PAR makes reduces SSP, but the scale of the impact is much smaller than the equivalent impact of PAR on SBP. Rather, lower PAR on the sell side substantially lowers the minimum bids accepted into highly negative territory. Given the relatively high de-rated margins in the historic data set, the impact of VoLL pricing and the RSP on average SBP are minimal, but prices do rise on occasion to the cost of voltage control on account of the RSP and costing of demand control actions.

Table 13 Average and maximum/minimum cash-out prices following the retrospective application of policy packages to historic data (2010 – 2012)

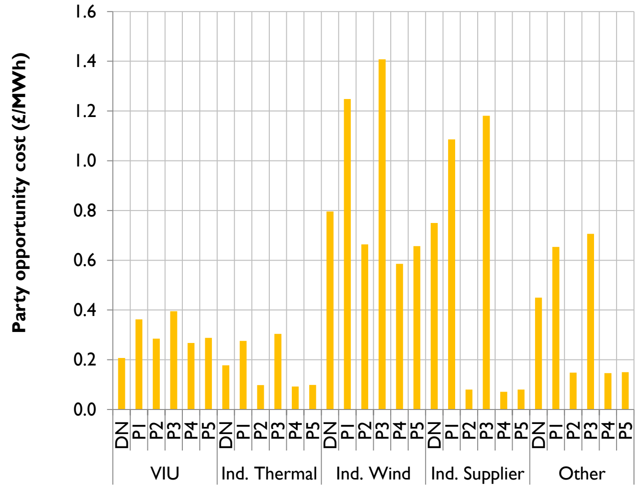
Package	SBP £/MWh		SSP £/MWh	
	Average	Max	Average	Min
DN	68.9	503.4	35.0	-17.2
P1	81.5	6000	33.8	-153.5
P2	85.2	6000	33.3	-255.8
P3	85.4	6000	33.3	-255.8
P4	81.7	6000	33.8	-153.5
P5	85.4	6000	33.3	-255.8

The distributional effects of the policy packages can be seen in Figure 15, which indicates the opportunity cost of imbalance to parties as a function of their credited energy volume (CEV). It indicates that those parties that are typically poor at balancing (such as independent suppliers and wind parties) are most exposed to cash-out and therefore most exposed to the increasing PAR marginality of packages. However, the application of single pricing compensates for this by

[41] Note that the table shows results for SBP and SSP when they are the main price. The impact of the packages on average SBP and SSP in all periods (including reverse priced periods) would be lower.

creating an opportunity for these parties to benefit when out of balance in an opposing direction to the system, thereby reducing their overall opportunity cost.

Figure 15 Distributional effects of retrospective policy changes to historic outcomes



Some of the effects demonstrated by the historical analysis are also observed in the future analysis. However, due to the evolving capacity mix and demand, and the inclusion of participant response to cash-out reform which is not captured in the historical analysis, there are some significant differences observed and key messages identified which are not apparent in the historic analysis.

4.2. Future analysis – Do Nothing case

Assessing results under the Do Nothing (DN) case is important to separate the effects of proposed cash-out reforms from underlying changes to the system over time. In particular, the combination of the evolving capacity mix (and margin) and increasing commodity prices (including the Carbon Floor Price) are expected to have a significant impact on system imbalances, cash-out prices and wholesale market prices.

The expected substantial increase in intermittent renewables on the system, coupled with the retirement of coal and older gas plant, which are more controllable, is forecast to reduce the balancing capacity of the system over time. Wind output, which is relatively difficult to forecast compared to conventional plant, will increasingly contribute to imbalance volumes resulting in greater variability as seen by the progressive widening distributions of NIV, shown in Figure 16. These widening distributions highlight the increasing importance of the BM, and cash-out regime, as they suggest that a greater proportion of energy will be traded through cash-out in the future. Annual gross imbalance volumes are forecast in the modelling to increase from around 28 TWh/yr in 2012 (9% of demand) to 43 TWh/yr in 2020 (14% of demand) to 58 TWh/yr in 2030 (16% of demand)[42].

[42] Note this is not the total balancing that the SO has to undertake but rather the gross absolute value of all party imbalance volumes.

It is important to recognise that parties are likely to respond not only to changed balancing incentives under cash-out reform, but also to changes to the underlying capacity mix and the direction and propensity for the system to be out of balance. Figure 17 shows the change in NIV (labelled ST) after including the change in position bias adopted by parties in the modelling. The net effect is to make the system shorter, particularly by 2030, than it would otherwise have been. As explained further below, this is the result of an increasing spread between the SSP and the MIP, making it less attractive to adopt a long position as a risk management strategy against high SBPs.

Figure 16 Evolution of NIV distributions under DN before short term response

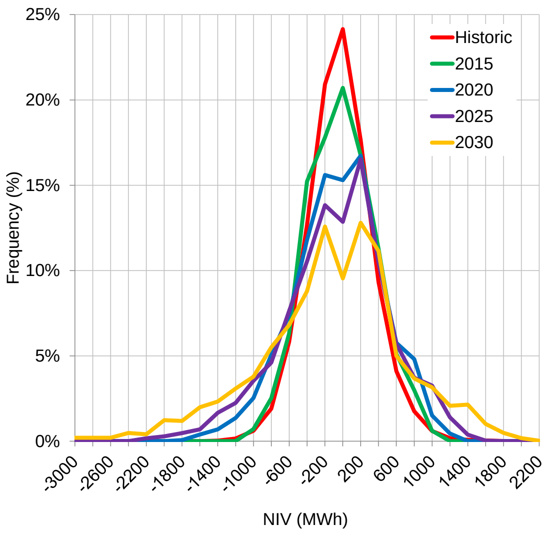
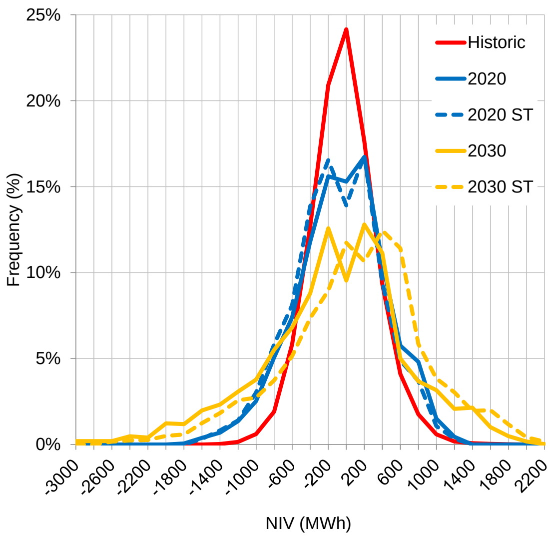


Figure 17 The effect of short term response on NIV distributions under DN



In combination with steadily rising commodity prices, greater variability in the magnitude of imbalance volumes will underpin increases in both the magnitude and variability of cash-out prices and consequently MIP. Figure 18 and Figure 19 indicate these changes. Of particular note is the evolution of the spread between cash-out prices and MIP:

- The system is currently characterised by asymmetrical spreads where the difference between average SBP (when it is the main price[43]) and MIP is greater than the difference between average SSP (when it is the main price) and MIP. This has largely driven the historical long hedging strategy of parties as buy side exposure has been greater than sell side exposure.
- This situation is expected to continue into 2015 before a steady reversal as the incidence of subsidised renewable plant bidding into the BM at negative prices (the opportunity cost of lost subsidy) being captured within the cash-out price calculation increases. Following this trend, spreads are forecast to become largely symmetrical by 2025.
- By 2030, the substantial capacity of subsidised renewables is expected to result in a situation in which sell side spreads are greater than buy side spreads and the SSP is negative on average. Avoiding negative SSPs will become a strong motive for shortening hedge positions.

[43] Note that the cash-out price results in this section are for the cases when SBP or SSP is the main price.

Figure 18 Evolution of average prices under DN

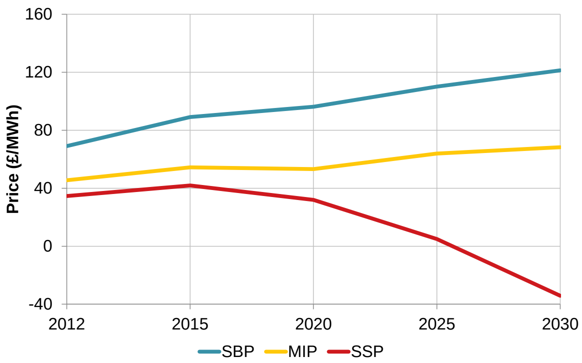
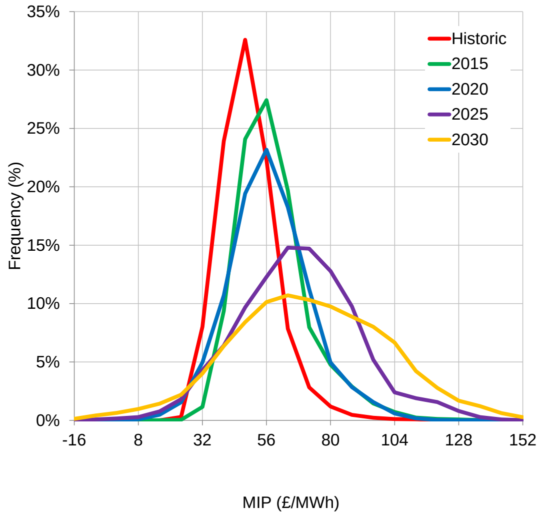


Figure 19 Evolution of MIP distributions under DN



MIP is expected to increase steadily over time in line with underlying capacity mix and commodity price changes but also become increasingly variable. This is highlighted by the widening distributions shown in Figure 19. The incidence of negative prices is modelled to be 1.2% (109 hours) by 2030. The incidence of negative prices is a function of many factors including the level of interconnection, the flexibility of the demand side and the strategy of the SO in managing the system with large volumes of asynchronous plant. Hence, there is some uncertainty surrounding this figure. DECC, in its EMR analysis, suggested several hundred hours of negative prices in 2030 under its central scenario.

4.3. Future analysis – policy packages

4.3.1. Cash-out prices

System Buy Prices (SBPs)

In all cases, the effect of the policy packages is to sharpen cash-out prices (i.e. increase SBPs and decrease SSPs). This is particularly true for SBPs, since in addition to more marginal PAR are also impacted by the RSP (in all packages) and costsed demand control actions (P3, P4, P5).

Figure 20 Evolution of average SBP (main price) under policy packages

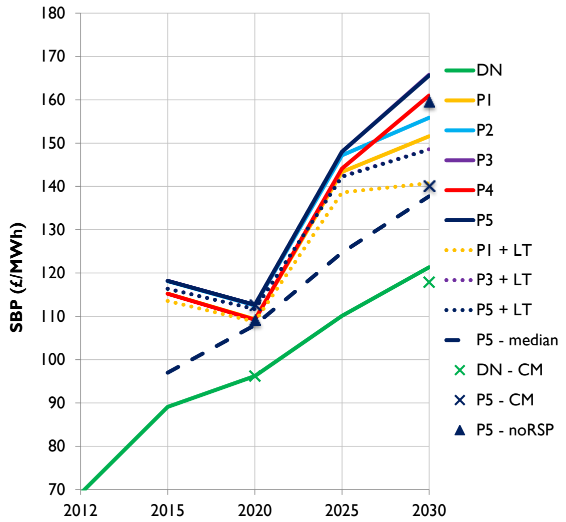
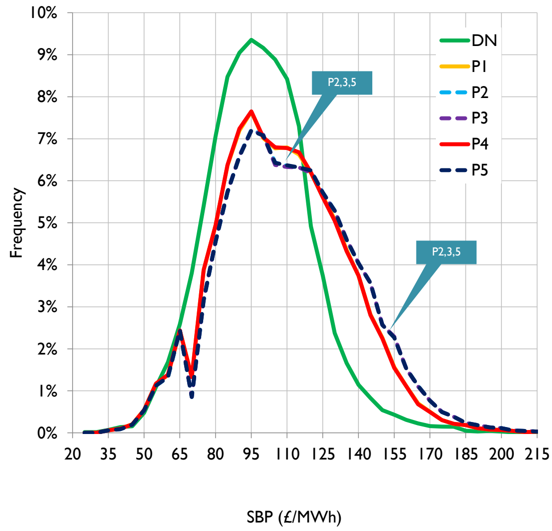


Figure 21 SBP (main price) distributions under policy packages in 2020



All packages result in a step increase in SBP compared to DN. This can be seen in both the evolution of averages over time (Figure 20) and in the distribution of prices in 2020 (Figure 21). The largest driver of this step change is the increase in PAR marginality, particularly in the earlier years of assumed relatively high margins and low levels of EEU, where the effect of the RSP and costing of demand control actions is small. Moving from PAR500 to PAR50 is found to increase average SBPs (main price) by ~£9.5/MWh in 2020 and ~£14.5/MWh in 2030. The modelling shows a further increase in average SBP (main price) moving from PAR50 to PAR1 of ~£3.1/MWh in 2020 and ~£4.4/MWh in 2030.

The jagged shape of average SBPs under the policy packages relative to DN shown in Figure 20 indicates how sensitive SBPs are to the RSP. The reduction in average main SBPs between 2015 and 2020 corresponds to the increase in de-rated capacity margins for the capacity scenario modelled. Likewise, the subsequent sharp increase to 2025 corresponds to a tightening system. Considering the RSP has the potential to raise the offer price of a generator from a utilisation fee of typically around £150/MWh to a replacement price of up to £6,000/MWh, small changes in reserve margin can have a significant impact on average main SBPs. To disentangle this effect, a sensitivity around P5 was modelled without the application of the RSF (as seen by the triangles of Figure 20). In 2020, it was found that the RSP raises average SBP (main price) by ~£3.5/MWh, with a de-rated capacity margin of 15.5%. In 2030, this effect increases to ~£6.0/MWh, with a de-rated capacity margin of 1.4%[44].

The consequences of costing demand control actions really only becomes apparent in 2030 when the volumes of EEU are large in the scenario modelled. In 2030, P3, P4 and P5 increase at a much greater rate than P1 and P2 such that the effect of costing demand control actions is

[44]Here the reserve margin refers to the amount of excess capacity in each half-hour period relative to demand. This should not be confused with the de-rated capacity margin which is an annual measure of capacity adequacy.

greater than that of increased PAR marginality. Costing demand control actions is modelled to have a ~£9.7/MWh effect on main SBPs in 2030.

Single pricing will only indirectly affect the main cash-out price by way of the short-term response that it may in-part influence. Unlike changing marginality or the introduction of costing demand control actions, single pricing does not affect the magnitude of main cash-out prices, but significantly changes the reverse price (setting it equal to the main price) with consequent impacts on party cashflows.

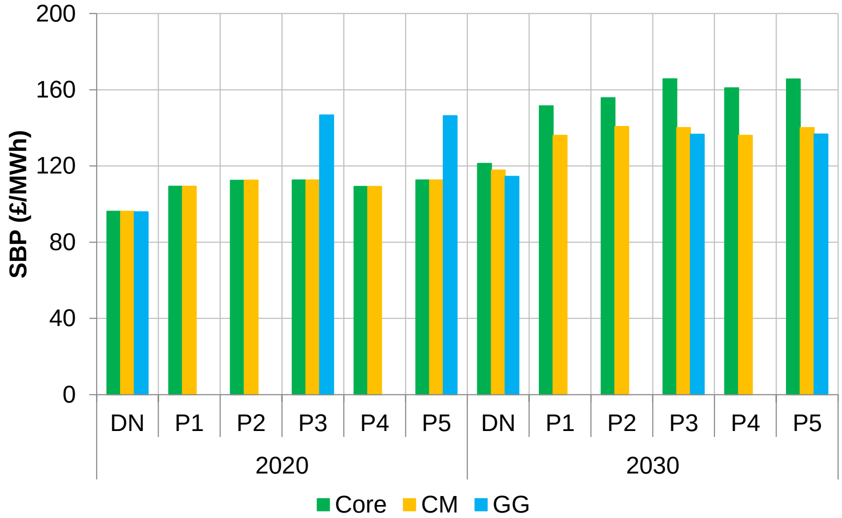
The modelled LT investment in additional capacity resulting from strengthened cash-out price signals mitigates the impacts of the RSP and costing demand control actions by checking the upward trajectory of SBP in 2030. This is due to an easing of the tight reserve margin (lessening the impact of the RSP) and reductions in the volumes of EEU (lessening the impact of VoLL costing). In earlier years, the impact of additional capacity on the system is less pronounced.

The analysis suggests that average SBPs are heavily influenced by the pricing effects of the RSP and costing voltage control and load disconnection when the system is tight. The RSP has the ability to raise rapidly prices into the £'000s/MWh range; similarly, policy packages with costed demand control actions (P3, P4, P5) price lost load events at between £6,000/MWh and £17,000/MWh[45], whereas under DN (and packages P1, P2) these events are not costed. Under the CM sensitivity capacity mix with greater reserve margins and much lower levels of EEU, the impact of the RSP and costed demand control actions on SBP is significantly reduced.

The presence of the RSP and costed demand control actions heavily influence the mean SBPs under tight conditions but have less impact on the median. The dashed line of Figure 20 demonstrates the extent of this effect; by 2030 the median SBP under P5 is ~£27.9/MWh lower than the average. This line also indicates how the median is relatively insensitive to changes in reserve margin in comparison to the mean average. The distribution of prices in Figure 21 indicates the expected range of main SBPs in 2020, which is assumed to have an adequate capacity margin, and hence is representative of a more typical year (particularly if the introduction of a CM under EMR reduces the risk of tight margins).

[45] VOLL prices have been informed by a separate study undertaken by London Economics for Ofgem as part of the EBSCR process. Under the core no-CM scenario voltage control is priced at £6000/MWh and load disconnection at £17000/MWh. Under all other capacity mix scenarios (the with-CM and Gone Green) both load disconnection and voltage control are priced at £6000/MWh

Figure 22 **Average SBP (main price) under different capacity mix sensitivities**



To explore this further, the CM and GG sensitivities, undertaken for a subset of the policy packages, demonstrate the effect on SBP of systems with changed capacity margins. Referring back to Figure 6, it is evident that the de-rated capacity margin in 2020 under GG is lower than the core scenario (and CM sensitivity). Conversely, both the CM and GG sensitivities have higher de-rated capacity margins in 2030 than the core scenario. The corresponding effect on average SBP can be seen in Figure 22.

In 2020 the GG SBP is significantly higher than the other scenarios under P3 and P5 on account of the interaction between the tighter margin and the RSP. The opposite is true in 2030 where the average SBP under the core scenario is affected by the RSP (and costing of demand control actions) to a much greater extent than the CM and GG sensitivities with greater headroom. These scenarios clearly demonstrate the sensitivity of SBP under the policy packages to the de-rated capacity margin.

System Sell Prices (SSPs)

Average SSPs (main price) under the policy packages exhibit a steep decline between 2015 and 2030. However, this decline is dominated by changes to the underlying system (capacity mix, commodity prices and NIV variation) and less so from the proposed policy packages. Therefore, unlike SBP, differences in SSP across the packages are expected to be relatively small. This is due to the following reasons:

- Offer (buy side) curves have typically exhibited greater ‘shape’ than bid (sell side) curves. The relatively flat nature of bid curves makes them less responsive to changes in the marginality of PAR
- In addition to increased PAR marginality, offer curves are subject to the RSP and costed voltage control and load disconnection; bid curves have no equivalent policies, and
- The sharp decline is driven by the increasing presence of subsidised renewable plants in the utilised section of the bid curve (i.e. falling within normal NIV ranges), which is true of all policy packages and DN alike

Figure 23 Evolution of average SSP (main price) under policy packages

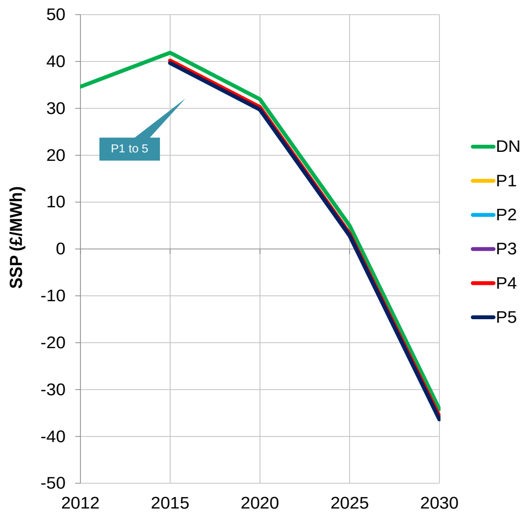
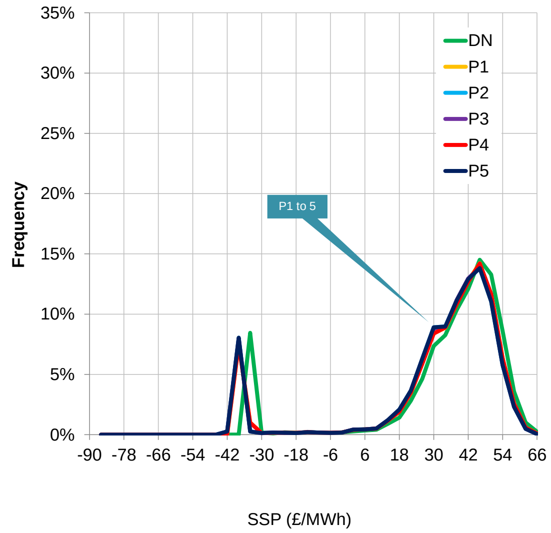


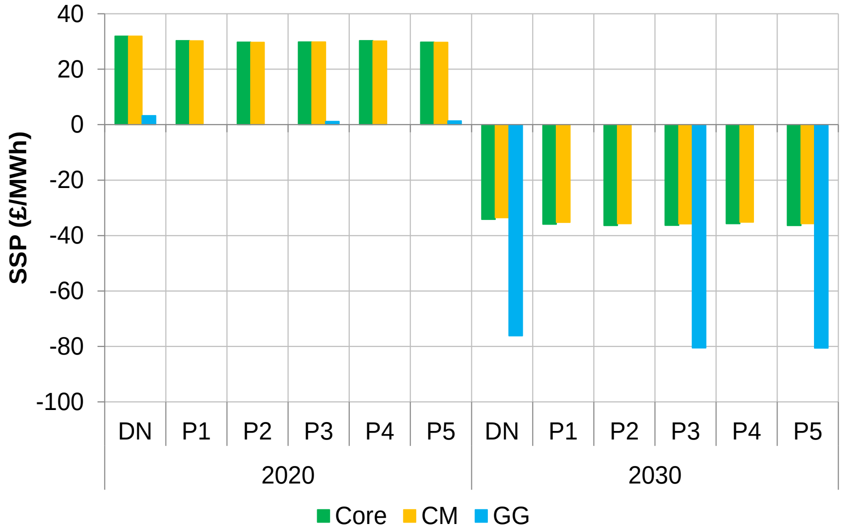
Figure 24 SSP (main price) distributions under policy packages in 2020



The effect of having an increasing proportion of accepted bids from renewables featuring in the cash-out price calculation is that bid curves become characterised by step changes corresponding to the level of subsidy for each type of renewable plant (e.g. the difference between 1 and 2 ROCs or the CfD strike price for onshore and offshore wind). Figure 24 indicates the relatively frequent utilisation of one such step in the -£38/MWh range in 2020.

In reality it is unlikely that renewable plant receiving the same level of subsidy will all bid at the exactly the same price, not least because generators may include shut down and start-up costs in their bids, which will differ by plant. Furthermore, the modelling relies on the assumption that there will be sufficient competition between renewables generators offering to curtail to drive bids down close to the opportunity costs of the lost subsidy. There is a risk, however, that bids with extremely negative prices get captured in the cash-out price calculation. This is particularly true under the most marginal PAR1 policy options. The sell side of the market need not necessarily have the same PAR level as the buy side of the market although this would increase the complexity of the arrangements.

Figure 25 **Average SSP under different capacity mix sensitivities**



Unlike SBPs, SSPs do not have an equivalent to the RSP or VoLL pricing that is sensitive to de-rated margins. Rather, any changes are purely driven by the properties of the underlying capacity mix. In the case of the CM sensitivity, this capacity mix is broadly similar to that of the core scenario, registering very little change to average SSPs in both 2020 and 2030 (Figure 25). However, under the GG scenario, much greater volumes of wind on the system (see Figure 5) increases the incidence of negatively priced bids within the cash-out price calculation. This results in significant reductions in SSP, particularly by 2030. The volumes of wind are extensive enough such that both onshore and offshore wind have accepted bids in the BM, with offshore wind bidding more negatively than onshore wind due to the larger number of ROCs or higher CfD received per MWh.

4.3.2. Cash-out spreads

Cash-out spreads are an indication of the magnitude of the exposure that parties have to being out of balance. On the buy side, this exposure is measured by the difference between the cost of procuring energy through cash-out (SBP) and what it would have cost if this imbalance was traded in wholesale energy markets (assumed at MIP); thus buy side spreads are equal to SBP minus MIP. Conversely, sell side spreads indicate the difference between selling spilled energy in wholesale electricity markets (assumed at MIP) versus through cash-out (at the lower SSP); the equivalent opportunity cost/spread is MIP minus SSP.

Both average buy side and average sell side spreads are expected to increase in magnitude over time across DN and all packages (Figure 26 and Figure 27). On the sell side, the rate of this increase is expected to be greater than on the buy side. However, the difference between DN and policy packages will be more distinguished on the buy side. These findings are consistent with outcomes for average SBP and SSP driven by changes to the underlying system as well as proposed cash-out reform policies.

Figure 26 Evolution of average buy side spreads (SBP-MIP) under DN and different policy packages

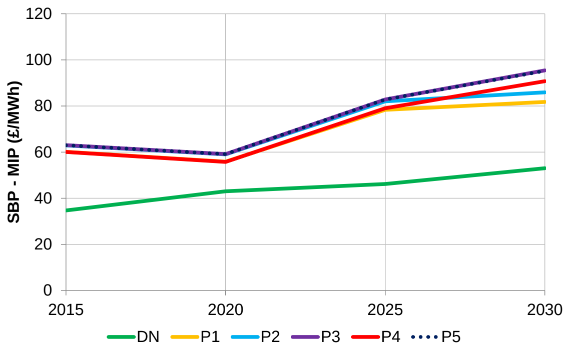
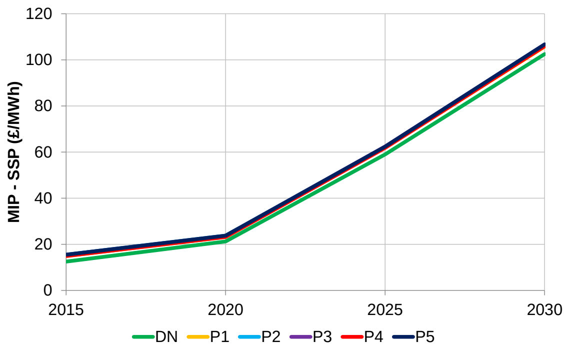
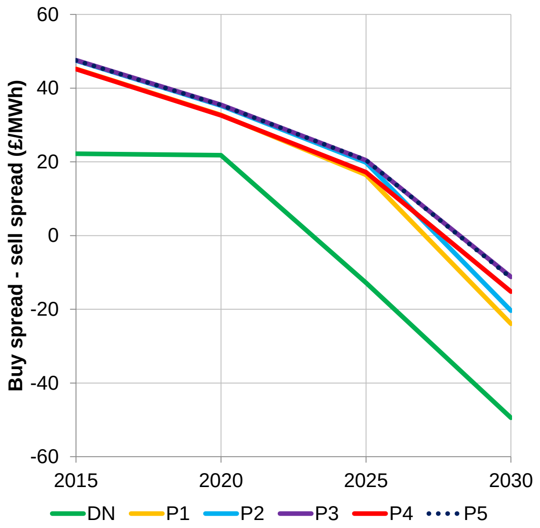


Figure 27 Evolution of average sell side spreads (MIP-SSP) under DN and different policy packages



To gauge how parties may respond to the relative magnitude of buy and sell side spreads, Figure 28 demonstrates how the difference in these spreads is expected to evolve. As the rate of sell side spreads is expected to increase at a greater rate than buy side spreads, there is a downward trend over time. By 2030, the magnitude of sell side spreads are expected to be greater than buy side spreads across DN and all policy packages as indicated by values below zero. In the absence of any other considerations this would result in a preference to adopt an increasing relatively short position over time.

Figure 28 Evolution of the difference between average buy side spreads and sell side spreads under DN and different policy packages



The spreads discussed above relate to the difference between the SBP and MIP and SSP and MIP when they are respectively the main price. Figure 29 and Figure 30 show the spreads considering all periods, including reverse priced periods, for packages P3 and P5. In the case of P5 the cash-out price is just a single line since this is a single pricing package. Figure 29 demonstrates that P3 would lead to wider cash-out spreads on average in all periods, as well as wider spreads between main prices and MIP. Figure 30 shows that the single price of P5 would on average be higher than the MIP initially, but converges to the MIP by 2030 as the effect of very low/negative cash-out prices when the system is long brings down the average.

Figure 29 Evolution of average COPs (main and reverse) for a dual price package (P3) and DN

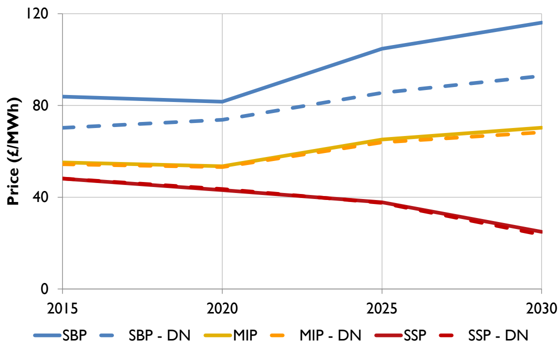
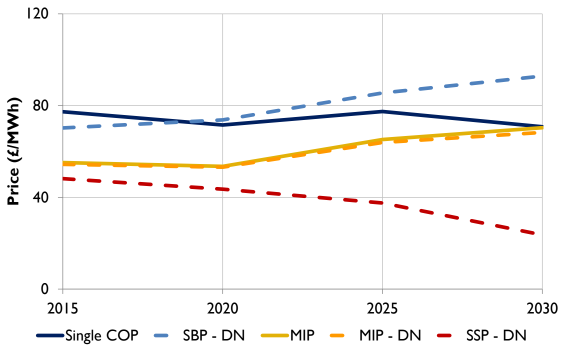


Figure 30 Evolution of average COPs (main and reverse) for a single price package (P5) and DN



4.3.3. Short term balancing incentives

System level impacts

To understand the overall impact of a cash-out reform policy package on the short term response of parties there are three key factors to consider:

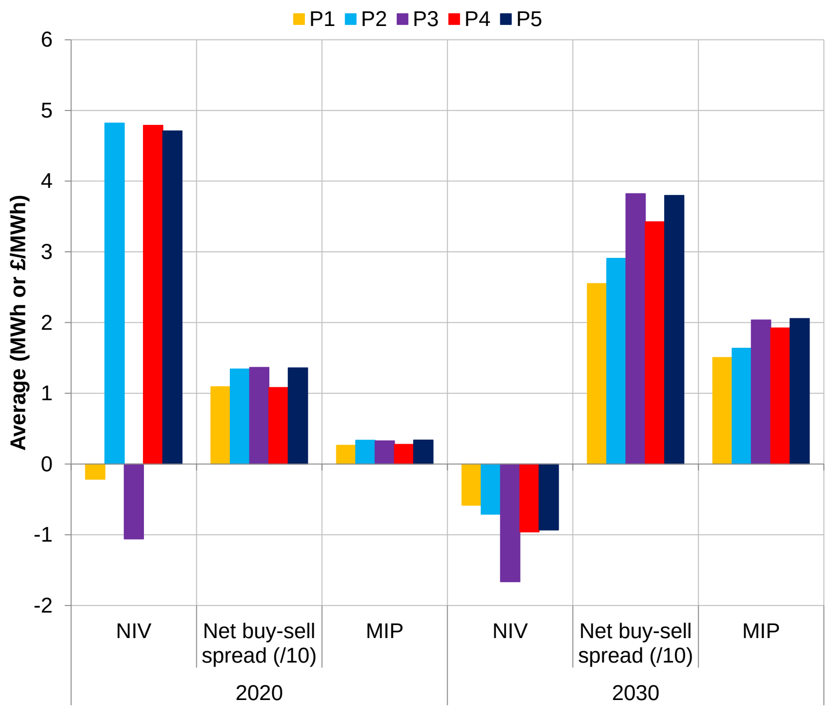
1. The impact on cash-out price spreads from the proposed cash-out reform policies alone (i.e. more marginal PAR, the application of the RSP and costing demand control actions).
2. The impact of introducing a single price policy which lowers the 'cost of hedging' for parties and creates incentives to adopt a position whereby parties can most benefit from being out of balance in an opposing direction to the system[46].
3. The impact on buy/sell spreads from the system moving longer or shorter. This has two opposing effects: if the system is moving shorter, there is potential to increase SBP due to an increase in average NIV; concurrently, if the system is moving shorter there will be an increase in the availability of lower cost offers in the BM as this energy is no longer contracted in wholesale energy markets.

In addition to a party's consideration of its own imbalance properties, these three factors will combine to result in party hedge positions. The net effect of hedging positions will influence system imbalance outcomes which in turn will influence cash-out prices, MIP and the investment signal generated moving from DN to the policy packages.

Figure 31 separates some of these combined effects as they compare to DN. For instance, the overall equilibrium impact of increasing the marginality of price under dual prices (PAR under DN > P1 > P3) in 2020 is to push the system longer in order to reduce the impact of the increasingly positive buy side spread.

[46] In aggregate as a result of the average daily hedge. It is not assumed that parties are intentionally trying to chase the opposite direction of the system from period to period given the difficulty and significant uncertainty associated with doing this.

Figure 31 **Change in key system parameters relative to DN under each policy package**



Under single price policies (P2, P4 and P5), all else being equal, the impact is to move shorter in 2020 as seen by comparing P3 to P5. Single price policies in this case offer two opposing incentives:

1. A lower cost of adopting any given preferred hedge position as some of the cost of this position will be recovered when the party is out of balance in an opposing direction to the system. This may exaggerate the magnitude of any directional hedge position adopted under the equivalent dual price package.
2. The potential for parties to alter their hedge position in order to benefit from spreads. This may result in a reversal of the direction of the hedge adopted under the equivalent dual price package.

Individual parties will respond according to one of these behaviours to different extents according to their own physical characteristics and the response of other parties. In the examples above, moving from P3 to P5, the net effect of all party responses is a shorter system under the single price package (P5), most likely driven by greater influence of the second of the incentives. This complex interplay between opposing incentives and aggregate system effects makes the directional outcomes with respect to NIV difficult to predict and attribute to any single dominant cause.

Hedge positions will have a small flow through effect onto cash-out prices and in turn MIP. Most MIP changes, however, are a consequence of the changed marginality of the cash-out price. Here MIP changes are broadly tracking the changes in the buy/sell spread. The difference in MIP from DN provides the signal for investment in new capacity under a policy package.

Importantly, the changes in hedge volume outlined here are very small when compared to total system movements. An average 5 MWh change in total hedge volume represents only 2% of one standard deviation of NIV in 2020. Thus, at a system level, party hedge changes offer very little differentiation between packages as seen in Figure 32 and Figure 33.

Figure 32 Distribution of NIV under DN and each package, 2020

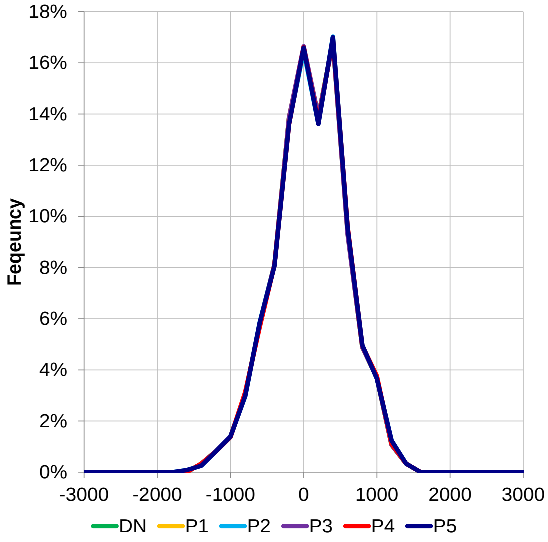
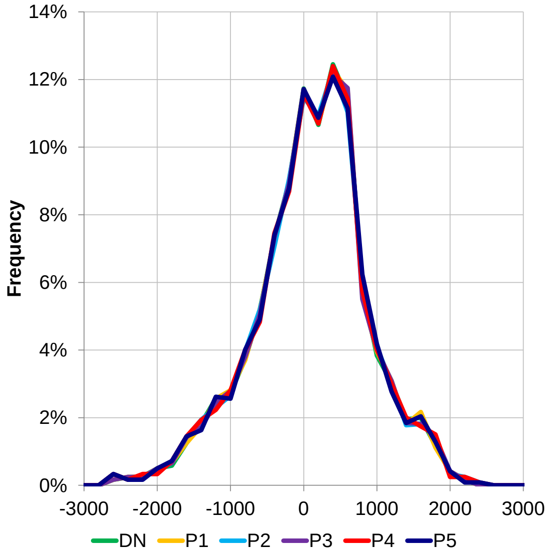


Figure 33 Distribution of NIV under DN and each package, 2030



Party level impacts

The Gross Imbalance Volume (GIV) of parties is an indication of their influence in setting imbalance system outcomes (i.e. whether the system is long or short). Figure 34 and Figure 35 show that independent wind generators become as important in determining system level energy imbalances over time as the VIUs despite contributing only 10% of the credited energy volume of VIUs. It is also clear that these parties have far greater influence than any of the other party types. As GIVs increase this broadly accentuates the impact of more marginal PAR levels.

Figure 34 Total gross imbalance volumes (GIV) of party types under DN and each package, 2020

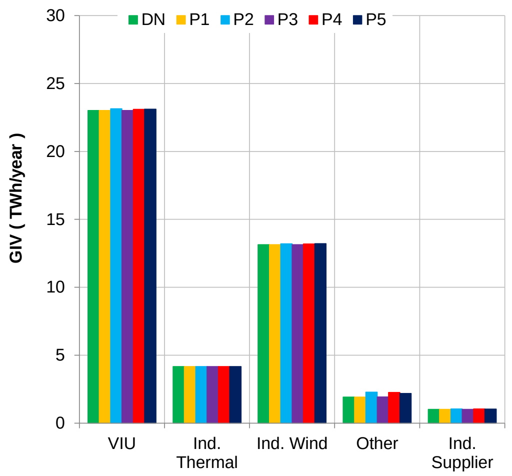


Figure 35 Total gross imbalance volumes (GIV) of party types under DN and each package, 2030

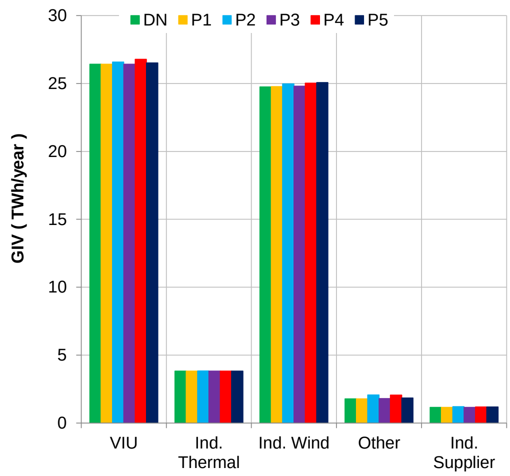


Figure 36 and Figure 37 indicate the average hedge position adopted by parties under DN and each policy package following the modelled short term response. These hedge positions are formed by parties attempting to minimise the opportunity cost of their imbalance and therefore represent their risk minimising position. They account for the combined effects of parties' imbalance properties and system conditions such as the direction and magnitude of NIV and the magnitude of buy and sell side spreads (see Section 4.3.2 for more details). Individual parties' incentives for hedging depend on a number of complex (and potentially offsetting) factors, particularly when comparing dual versus single pricing, which are outlined in more detail in Appendix B: 8.1. The section below describes the overall trends as a result of the modelling.

Under the dual pricing packages (DN, P1, P3), parties move longer on aggregate as prices become more marginal. The VIUs and independent thermal parties maintain long positions to mitigate the risk of forced outages on their generation plant. Independent wind (with a much wider range of imbalances) is an exception to this as it adopts consistently short positions under dual pricing in order to avoid increasingly negative SSPs.

By contrast, independent wind demonstrates a preference to be longer under single pricing policies, given the greater advantage of being long when the system is short. Parties with thermal generating assets still generally maintain a preference for being long, except the VIUs under some of the single pricing packages in 2030, which is likely in-part to be a response to the longer positions being taken by independent wind which lessens the benefit of being long for other parties.

It should, be noted that there can also be variation in response within each of these aggregate party types. For example, each of the VIUs (which are modelled independently) reflect quite a range of different portfolios and their corresponding imbalance distributions mean that their optimal hedging positions can be somewhat different to each other.

Figure 36 Average hedge position adopted by party types following short term response under DN and each policy package, 2020

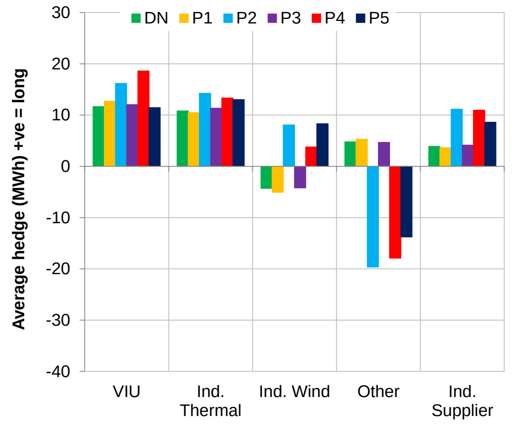
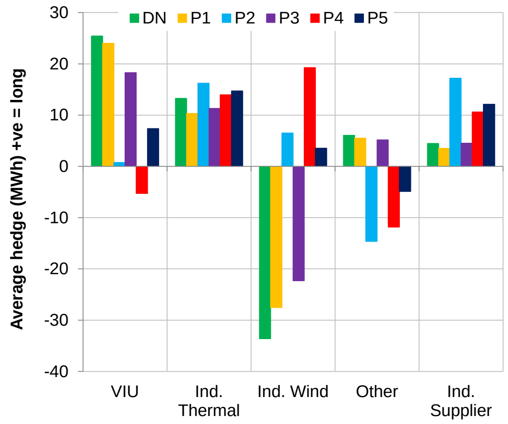


Figure 37 Average hedge position adopted by party types following short term response under DN and each policy package, 2030



When examining the average hedge positions of parties as a proportion of their GIV it becomes clear that the hedge taken by VIUs and independent wind parties is actually very small (Figure 38 and Figure 39). Placed in this perspective, it is likely that the motivation of these parties is primarily to minimise their exposure to cash-out. By contrast, independent thermal, suppliers and other parties, which are less likely to have imbalance volumes capable of influencing system outcomes, are more able to benefit from having imbalances in the opposite direction to the system and can take a more active approach in minimising their exposures.

Figure 38 Average hedge position as a percent of GIV adopted by party types following short term response under DN and each package, 2020

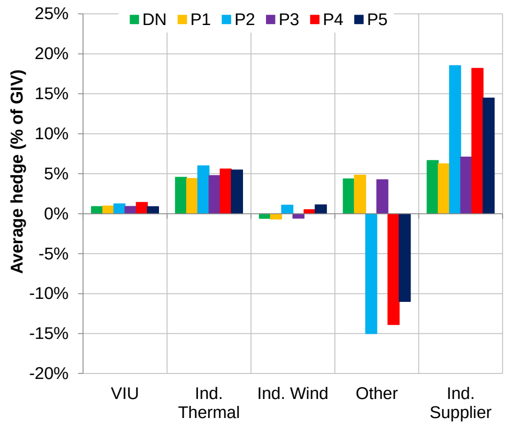
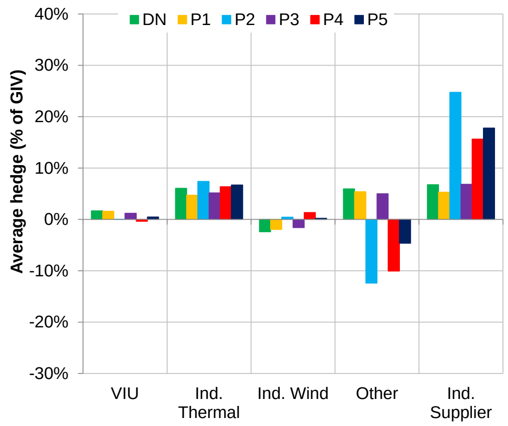


Figure 39 Average hedge position as a percent of GIV adopted by party types following short term response under DN and each package, 2030



4.3.4. Long term balancing incentives

As well as providing signals to parties to balance in the short term, cash-out prices should signal the value of investing in improving future balancing performance through better forecasting systems and improving plant reliability. For this investment to be efficient, imbalance costs for parties should closely mirror the costs imposed by their imbalances on the system. If imbalance costs are too low, parties will make insufficient investment in forecasting and plant reliability, thus increasing the costs to the system operator, and ultimately customers. If, however, imbalance costs are too high, parties may over-invest to achieve high levels of balancing accuracy, which collectively do not improve the system level imbalance to a degree justified by the costs of the investment by the individual parties. This may be because there is natural diversification of imbalances across multiple parties, and hence an average 5% improvement in balancing performance by all parties does not necessarily translate into a 5% reduction in imbalance volumes at the system level.

To assess how well the signals from the policy packages align with the underlying costs to the system operator, we have plotted the relationship between opportunity costs of all parties (the additional costs of being cashed-out rather than closing positions in the wholesale market at prevailing market price) against the Gross Imbalance Volume, and compared this to the NIV opportunity cost for the System Operator (the additional costs from resolving the system level energy imbalance through the BM rather than at market price) and which reflects the true consumer costs of balancing. Note that:

- The approach to calculating NIV opportunity (or consumer) costs of balancing is outlined in Appendix B: 8.2, and
- The overall approach to assessing long-term balancing incentives is described in more detail in Appendix B: 8.3

The change in NIV opportunity cost represents the 'real' cost savings for the consumer from a reduction in system imbalance volumes, whereas the party opportunity cost represents the *individual* party benefits from improved imbalance. However, because of the distributional effects within cash-out, as a result of the flows of imbalance charges and RCRC, a benefit for one party from improved imbalance can lead to a negative impact on another (as improved balancing reduces the overall pool of RCRC).

The costs of the investment in improved balancing still ultimately need to be paid for by the consumer, but the distributional impacts within cash-out across parties mean that real net consumer benefits only materialise if the overall cost of system balancing is reduced by a level that exceeds the cost of the investment across all parties.

The results for 2020 and 2030 are shown in Figure 40 and Figure 41 below.

Figure 40 Long term imbalance incentives for DN and each package, 2020

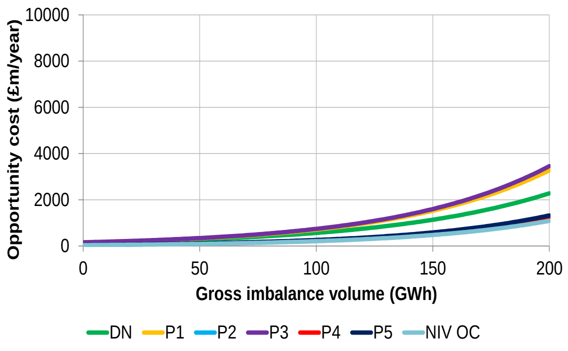
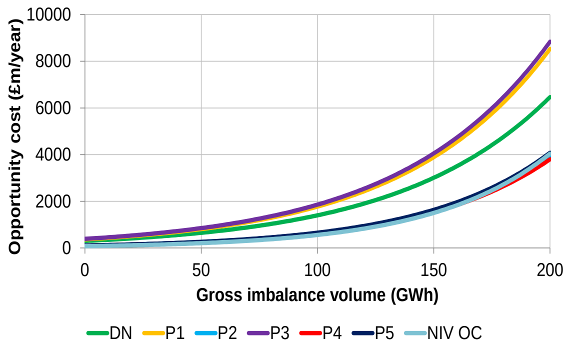


Figure 41 Long term imbalance incentives for DN and each package, 2030



The curves represent the best fit through the simulation results. As Gross Imbalance Volumes increase the opportunity costs of the imbalance also increase according to an exponential relationship. This is particularly true in 2030 under the tighter system. The light blue line represents the NIV opportunity cost or the 'efficient benchmark for investment' against which we compare the other lines. The party exposures under the single price packages (P2, P4, and P5) closely align with the underlying NIV opportunity costs. There is some variation between the packages given the different PAR values and pricing of demand control action, and no one package exactly aligns with the underlying NIV opportunity cost, which is as would be expected since the RSP, for example, will not be 100% accurate (in terms of reflecting the actual costs to the SO of using STOR).

It can be seen that for the DN case and the dual pricing packages, P1 and P3, the opportunity cost curves for parties are significantly in excess of the underlying NIV cost, suggesting that on average the imbalance costs charged to parties are in excess of the costs that they impose on the system, particularly under more marginal cash-out prices. This is not to say that the more marginal cash-out prices under P1 and P3 are not reflective of costs when the system is under stress conditions, but rather that dual pricing imposes imbalance costs in excess of the costs to the SO under normal operating conditions. As a result parties may invest or take actions to avoid this long term exposure to imbalance costs which are not justified in terms of added benefit to the system.

This analysis suggests that the incentives to invest in long term balancing performance are weaker under single price packages than dual price packages, but actually incentivise more efficient overall outcomes. However, this does not necessarily mean that balancing performance would deteriorate from current levels under single pricing packages since there is a general trend to more volatile cash-out prices given the evolving capacity mix, emphasised by greater cash-out price marginality. Table 14 below shows the estimated improvement in long term balancing performance by 2030 under the five packages, compared to current levels. The improvements are greatest under the dual price packages, but there are also improvements under the single price packages.

Table 14 Average GIV for DN and each package before and after long term imbalance investment, 2030

Package	Average GIV before investment (GWh)	Average GIV after investment[47] (GWh)	Improvement (GWh)
DN	79	71	8
P1	79	71	8
P2	81	75	6
P3	79	71	8
P4	82	76	6
P5	81	73	8

[47] Improvement in imbalance is assumed to be to the maximum of the rational cost-benefit indifference point or 10%. This recognises that there will be physical limits to which imbalance improvements can occur. However, it is difficult to say with certainty what the upper limit will be.

It is also important to note that the incentives for parties to cover their positions under peak conditions are strengthened by sharper cash-out prices equally under dual and single price packages. Hence, lower incentives to balance under normal conditions do not necessarily mean that parties would invest less to cover exposure to peak conditions and the signal for investment still flow through to forward markets.

In addition to the overall system consequences of individual parties investing in balancing improvements, there are also distributional effects among party types to consider. This is explored further in Appendix B: 8.2.

4.3.5. Investment in new generating or demand side response capacity

There are a number of factors that drive investment in new capacity[48], including:

- The level of wholesale electricity prices, and the spread between the wholesale price and generation costs
- Opportunities for selling Balancing Services to the SO via the BM or under Balancing Services contracts
- Volatility in prices and signals for flexibility
- The 'bankability' of forward prices and the availability of long term contracts with credit-worthy counterparties
- The possibility of securing additional revenues under the CM as proposed under EMR

Reforms to cash-out affect the first three of these factors directly, less so the others factors.

The regression analysis suggests that higher SBPs, driven by lower PAR, the RSP and costing of demand control actions will likely push up within-day and day-ahead prices, when the capacity margin is tight, and this would likely feed through into higher and more volatile forward prices.

Using the regression analysis it is possible to equate the increase in the wholesale price caused by cash-out reforms (Figure 43) with an equivalent change in capacity margin – providing an indication of the additional new capacity the market could in principle support[49] as a result of cash-out reform. Figure 42 below shows the results from the modelling under the five packages. It suggests that the impact of cash-out prices on the wholesale market is equivalent to around 700 MW in 2020 and between 2,000 MW and 3,000 MW of new generation capacity by 2030.

[48] New capacity is taken here to include demand side response as well as generation.

[49] The market is assumed to be able to support new capacity where the inframarginal rent and BM revenues are sufficiently and consistently high enough to cover all marginal and amortised costs of the investment as well as the required rate of return of the investing party.

Figure 42 Evolution of assumed (cumulative) investment under each policy package[50]

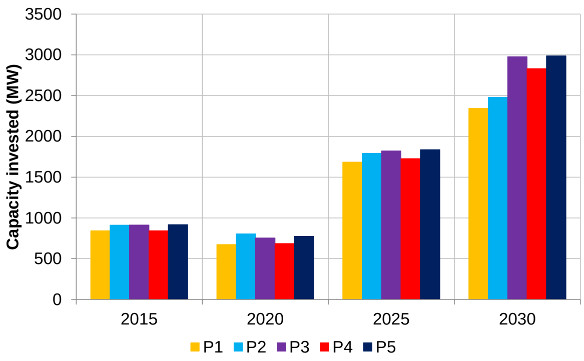
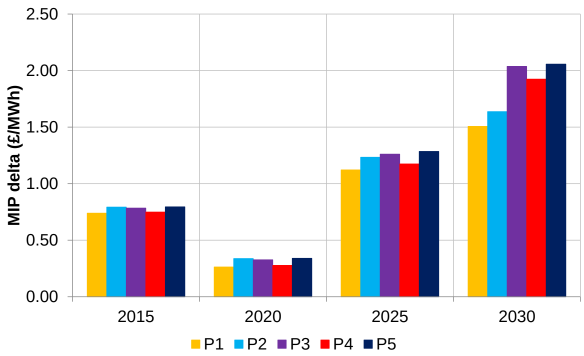


Figure 43 Evolution of difference in MIP between policy packages and DN – the signal for investment



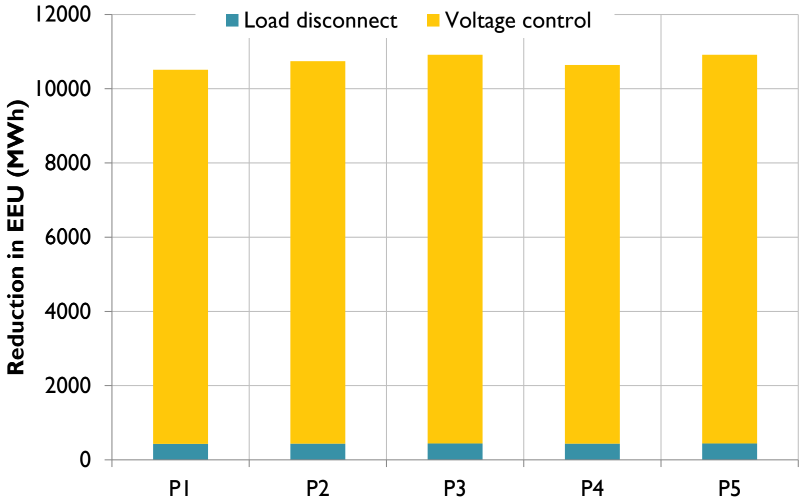
However, it cannot be concluded that the cash-out reforms will necessarily lead to these levels of increased investment, given the wide range of factors that impact on this decision, especially in the case of new generation. In particular, whether opportunities available in the wholesale market or in providing Balancing Services are more 'bankable' for lenders and investors will depend on the contracts on offer, which is a function among other things on forward market liquidity and the contracting strategy of the SO, which is in turn a function of its regulatory incentives.

Views expressed in the Technical Working Group sessions suggested this might be a zero sum game in terms of investment signals for new generation if the result of more marginal cash-out prices was simply to move demand for energy between the wholesale markets and the Balancing Services markets. By contrast, there was more confidence that policy options such as costing of voltage control and demand disconnection that put 'new money' into the system could strengthen investment signals overall. Peak energy previously being provided by customers for free would be priced according to VoLL, which should encourage new generation investment to 'compete' with voltage control and involuntary interruption. The potential effect can be seen by comparing the results for P3 (which includes costing of demand control actions) and P1 (which does not) in Figure 42 above. In 2030, P3 could potentially support an extra 630 MW of capacity relative to P1 reflecting the value of this capacity in avoiding cash-out prices set by VoLL.

Assuming that the cash-out policy packages do deliver the additional capacity indicated in Figure 42, the resulting reduction in EEU is shown in Figure 44. There is a significant reduction (~10 GWh+) in EEU across all packages in 2030, with the trend following the pattern of new capacity in Figure 42. However, the difference in EEU reduction across the packages is smaller than the differencs in new capacity, as the reduction in EEU is subject to rapidly diminishing returns, i.e. when the margin is tight the first 1-2 GW of new capacity lead to a significant reduction in EEU with each further MW leading to a smaller incremental saving.

[50] This reflects the absolute incremental capacity that could be supported up to 2030 relative to *no* additional capacity without the cash-out policy package. It is independent of the capacity supported by the price signal in preceding years.

Figure 44 Reduction in EEU following LT capacity investment for each package in 2030



A final consideration is the impact of the proposed CM. Views expressed by the Technical Working Group suggested that any changes to investment signals created through cash-out reform would be immaterial relative to the signals provided through the CM, although cash-out reform would likely influence how their bid into the capacity auctions. For the core analysis, we considered the impact of the cash-out packages in isolation of the CM. For the CM sensitivity we assumed that all new investment was driven by the CM rather than cash-out reform. Under this sensitivity capacity margins are on average higher, and the impact of the policy packages on cash-out prices is lower.

In summary, the analysis suggests that if wholesale electricity prices were the only driver of investment then cash-out reform could potentially lead to additional investment in an otherwise tight market, for example up to 3,000 MW by 2030. However, actual investment is dependent of a number of other factors including the demand for Balancing Services (which may diminish with additional investment), the 'bankability' of future revenue streams, and now the implementation of the CM.

However, even with a CM in place, policy considerations such as reducing PAR or introducing a RSP should enhance security of supply through improved interconnector response to scarcity events and activating greater demand side response as discussed below.

4.4. Party-level results

4.4.1. Balancing net cashflows

Net cash flows from balancing are taken here to be the sum of incoming and outgoing cashflows from three sources:

- Net Imbalance Charges (NIC) which represents the charges to a party due to its imbalance. In periods when the party is short this equates to procuring its imbalance at the SBP so will be an outgoing cashflow. In periods when the party is long this equates to selling its imbalance at the SSP so will be an incoming cashflow.
- Residual Cashflow Reallocation Cashflow (RCRC) which recovers or returns differences in the aggregate NIC according to the total credited energy volumes of parties. Parties with

low imbalance will typically be net beneficiaries, with RCRC being more positive than their own NIC, and vice versa for parties with high imbalance.

- Balancing Mechanism Earnings (BME) which represent the revenue from accepted offers and bids into the BM. Note that we are only including those actions that contribute to energy balancing, and not actions taken to support system balancing, such as resolving transmission constraints. As the BM currently operates a pay-as-bid market and the model is not agent-based, all BMEs are calculated using a single weighted average pay-as-bid price.

From a cashflow perspective, independent suppliers and wind parties tend to have the greatest imbalance exposure (Figure 45 and Figure 46) as a proportion of their volumes as historically, they have been less able to balance their positions. This is true under both DN and the proposed policy packages as underlying system changes and the physical properties of these parties result in large imbalances. This becomes increasingly the case moving from 2020 to 2030 as changes to underlying system conditions drive larger variation in NIV and corresponding increased imbalance exposure. The modelling suggests that the sharpening of cash-out prices due to increasing PAR marginality, the application of the RSP and costing demand control actions will accentuate this exposure and further disadvantage these parties. The two dual price packages (P1 and P3) result in a net increase (compared to DN) in outgoing cashflows from independent suppliers and wind parties. Under P3 in 2020 this is £1.2/MWh and £1.7/MWh respectively; £3.7/MWh and £4.8/MWh in 2030.

Figure 45 Party-level net cashflows for DN and each policy package, 2020[51]

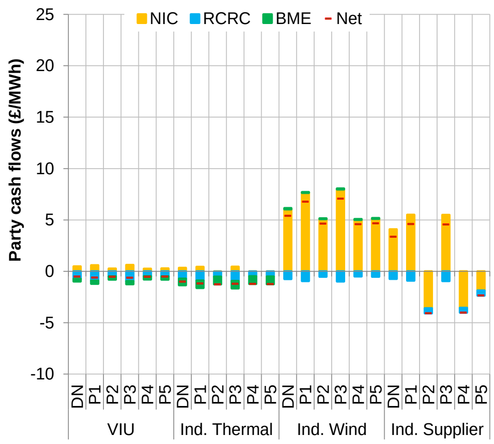
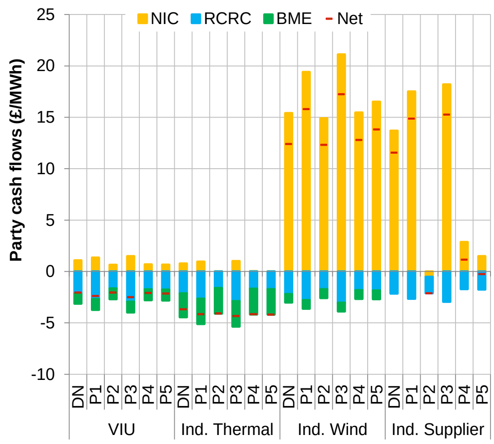


Figure 46 Party-level net cashflows for DN and each policy package, 2030



4.4.2. Opportunity cost

We use the term opportunity cost here to represent the loss to a party that is incurred by being out of balance as opposed to settling its entire position in the wholesale energy market. For instance, a short party in a short system will have to procure energy through cash-out at a price equal to SBP. This price is typically greater than the price at which this energy could have been

[51] Positive values represent outgoing cashflows. All quoted net cashflow and opportunity cost values are before assumed investment in improved reliability and forecast accuracy

procured ahead of Gate Closure, which for the analysis we assume is equivalent to the MIP. Likewise, for long positions in a long system, the price received for spilling energy (SSP) is less than what could have been received had the position been settled in its entirety in the wholesale energy market (again, assumed to be at MIP). These differences in price represent a cost to the party of being out of balance, termed here the opportunity cost. Under packages with single pricing, this opportunity cost also accounts for the lost benefit of not receiving a better price than MIP for helping the system by being out of balance in the opposite direction. Further details outlining opportunity cost trade-offs and hedging strategies under packages with dual and single pricing are discussed in Appendix B: 8.1.

Like the balancing net cashflows described above, the opportunity cost is greatest for those parties that are poor at balancing their positions (Figure 47 and Figure 48).

Figure 47 Party-level opportunity cost for DN and each policy package, 2020

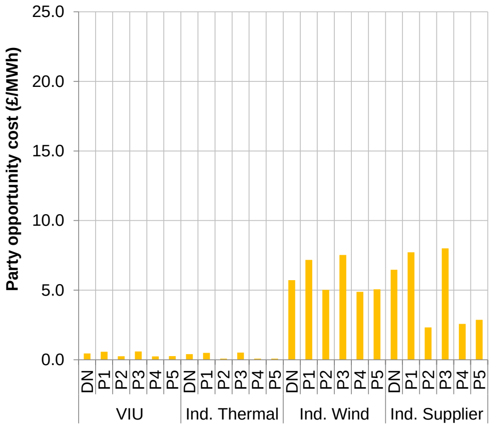
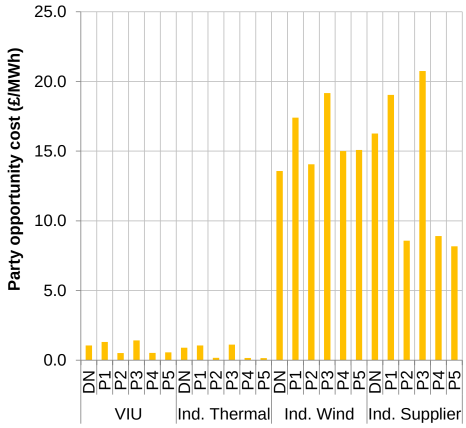


Figure 48 Party-level opportunity cost for DN and each policy package, 2030



4.4.3. Impact of single pricing

The modelling suggests that single pricing tends to offset the detrimental impacts of sharper cash-out prices for all parties, particularly independent suppliers and wind parties. This is because single pricing allows these parties to capture benefit when their imbalance is in an opposing direction to the system, whereas currently they only pay or receive the reverse price based on MIP when they are 'helping' the system. For independent suppliers this is particularly true to the point that they consistently fare better under single pricing policy packages than under DN. For independent wind parties the benefits of single pricing are enough to offset completely sharpening effects in 2020. In 2030, the benefit of single pricing for independent wind depends on the package, with a slight benefit recorded in P2 and mitigation of sharpening prices in P4 and P5.

The difference in captured benefit from single pricing between independent suppliers and wind parties reflects the fact that independent wind parties are more frequently out of balance in the same direction as the system (and likely driving this system imbalance) than independent suppliers, and therefore benefit less from the more favourable reverse price. However, Figure

49 and Figure 50 demonstrate that this benefit is dependent on the correlation of forecast errors across wind parties[52]. As the correlation of production imbalance between wind parties increases, there is increasing likelihood that wind imbalances may drive system imbalances. In these instances, wind parties will frequently set whether the system is short or long and thus will rarely be able to receive benefits under a single pricing policy option.

Figure 49 Independent wind balancing cashflows for DN and each policy package with 1wind sensitivity, 2030[53]

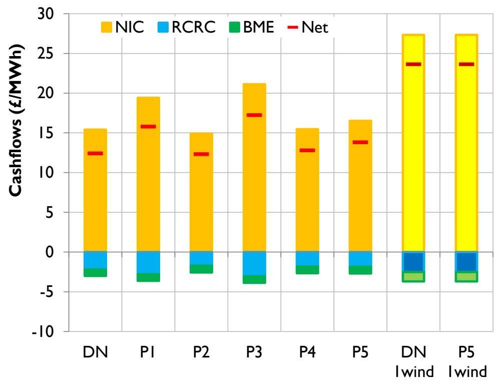
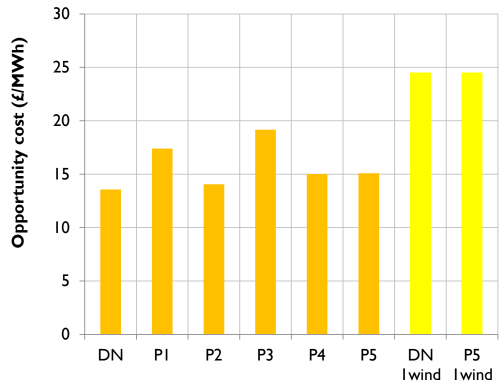


Figure 50 Independent wind opportunity cost for DN and each policy package with 1wind sensitivity, 2030



This assumption does not just have distributional consequences for independent wind parties, but also consequences for system level prices (Table 15).

Table 15 Difference in prices using 100% wind correlation compared to core scenario, 2030

Price	DN	P5
Average SBP	-£0.3/MWh	+£4.2/MWh
Average SSP	-£1.7/MWh	-£1.8/MWh
Average MIP	-£0.0/MWh	+£0.3/MWh

The extent to which wind parties will exhibit correlations in their production imbalance will be dependent on a number of things:

- The number of forecasting services available to wind parties and the diversity of sources from which these forecasting services draw their information. For instance, if only a limited number of forecasting services exist, or they all draw their information from a single source, then incorrect wind speed predictions are likely to be systematic and wind

[52] It should be noted that the base case that models two independent wind parties with zero production imbalance correlation already offers a relatively high degree of correlation for the simple fact that there are only two parties where in practice there would be many. However, within each of these two parties, the overall distribution reflects the historic correlation of wind forecast errors as the simulated distributions were derived from historic outcomes; i.e. if the historic results were perfectly correlated the distributions would be wider than they are and vice-versa.
[53] Positive values represent outgoing cashflows.

imbalance correlations are likely to be high. Conversely, the presence of many services and / or sources of information are likely to mitigate this.

- The extent to which wind parties are regionally grouped. For instance, if wind farms are predominantly located in few areas with the best wind resources, then unexpected wind events in a region are likely to affect all wind farms in that region and wind imbalance correlations are likely to be high. Conversely, a diversified set of locations for wind farms will mitigate this.

Even with very high production imbalance correlation among wind parties, single pricing policy packages will still in-part mitigate their imbalance costs so will be preferable for these parties than dual pricing policies. However, in this case the costs of increased PAR marginality, the RSP and costing demand control actions will be particularly pronounced and disadvantage wind parties to a much greater extent than any other party type.

5. SUMMARY OF RESULTS

5.1. Overview

The changing generation mix over time is expected to drive the greatest changes to the cash-out exposure of parties. This is primarily due to substantial increases in wind capacity leading to greater variability in system imbalances and hence greater volumes of energy traded through cash-out (rising from around 9% of demand in 2012 to 16% by 2030). Steadily increasing commodity prices are expected to lift average main SBPs from £89/MWh in 2015 to £121/MWh by 2030. Conversely, the large volumes of subsidised renewables are expected to result in a sharp decrease in average main SSPs from a high of £42/MWh in 2015 to -£34/MWh by 2030. Under DN policy, energy balancing costs are expected to increase from around £74m in 2012 to around £753m by 2030, with the impact of negative bids being a key driver of this increase. Net Imbalance Charges may rise to as much as £1.5bn by 2030. The impact of subsidies 'polluting' balancing costs could be very significant, with a large proportion of the additional costs being charged back to low carbon generators, potentially creating a spiralling effect where low carbon generators require higher subsidies to cover rapidly increasing balancing costs.

Another message coming from the modelling is that under DN policy, the asymmetry in cash-out prices on the SBP side is likely to reduce as the spread between SSPs and market prices starts to increase. This should diminish the current incentives on parties to be systematically long, as the desire to avoid very negative SSPs will start to influence behaviour as much as attempting to avoid very high SBPs.

Hence, under DN policy the modelling suggests that cash-out prices will become more expensive (SBPs higher, SSPs lower) and more volatile. Layering on the proposed cash-out reforms is expected to exaggerate the effects further. The extent to which this is the case depends on the combination of the choice of individual reform proposals and on how tight the system is. In Table 16 we show approximately the impact of the different policy considerations on cash-out prices. It can be seen that the impact of the considerations on SBP are greater under the tighter system assumed in 2030.

Table 16 Estimated effect of individual policy considerations following short term response (£/MWh)

Cash-out price	Policy effect	Methodology to estimate[54]	2020	2030
SBP - average	PAR500 to PAR50	P1 - DN - RSP effect - VOLL effect	+9.5	+14.5
	PAR50 to PAR1	P3 - P1 - VOLL effect	+3.1	+4.4
	RSP effect	P5 - P5 noRSP	+3.5	+6.0
	VoLL effect	P5 - P2	+0.2	+9.7
SSP - average	PAR500 to PAR50	P1 - DN	-1.7	-1.7
	PAR50 to PAR1	P3 - P1	-0.4	-0.4

[54] Given that it was only possible to run a discrete number of packages and sensitivities within the scope of this project, it is not possible to separate out each individual impact explicitly.

5.2. Security of supply

Improvements to security of supply from the modelled cash-out packages are expected to result from:

- Strengthened signals to invest in new demand side response capabilities or generating capacity as a result of sharper cash-out prices feeding into peak market prices
- Increased signals through higher imbalance charges for investment in improved plant reliability and forecasting accuracy
- Improved signals for the dispatch of flexible generation and utilisation of demand side response from cash-out prices being more responsive to system conditions, and
- Greater responsiveness of interconnectors to conditions of system stress in the GB market

Figure 51 shows the top 2.5% of SBPs in 2030 under the policy packages compared to DN. It can be seen that in a tight market, prices would rise up to VoLL before load disconnection, which should ensure that interconnectors are importing at maximum before customers are disconnected, which would not be the case under DN. This also suggests that customers with lower VoLL than the administrative level would self-interrupt sooner, enhancing security of supply for customers with higher VoLLs.

The cash-out policy packages would likely make SBPs far more responsive to system conditions, and increase their volatility. This should signal the additional value of flexible generating capacity and demand side response. Figure 52 shows the standard deviation of SBP under the policy packages relative to DN, demonstrating a rapid increase particularly for those packages in 2030 with costed demand control actions.

Figure 51 High end SBP cumulative distribution for different policy packages, 2030

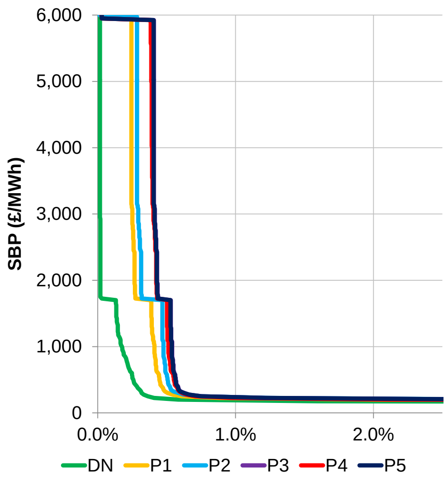


Figure 52 Evolution of standard deviation of SBP under different policy packages

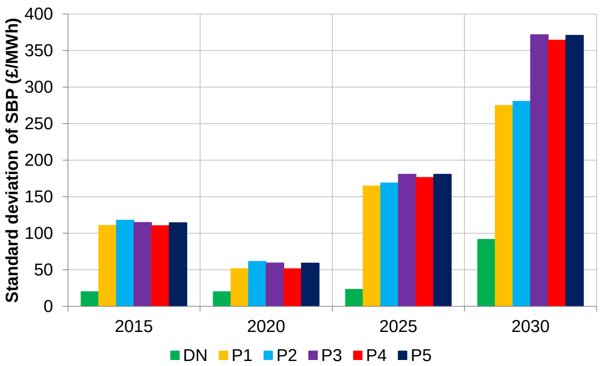


Table 17 summarises the security of supply metrics that could be quantified in the modelling for each of the policy packages.

Table 17 **Influence of policy packages on security of supply metrics**

Package	Investment in new demand side response or generation capacity 2020 / 2030 (MW)	Responsiveness of cash-out prices to system conditions as measured by increase in standard deviation of SBP 2020 / 2030 (£/MWh)	Reduction in EEU resulting from additional capacity and improved interconnector responsiveness 2030[55] (GWh)
P1	~670 / ~2340	+32 / +183	~10.5
P2	~800 / ~2480	+41 / +189	~10.7
P3	~750 / ~2980	+39 / +280	~10.9
P4	~680 / ~2830	+31 / +273	~10.6
P5	~770 / ~2990	+39 / +279	~10.9
Notes	In absence of the CM	DN: 20 / 92	Relative to DN

For the core analysis, we considered the impact of the cash-out packages in isolation of the CM. For the CM sensitivity we assumed that all new investment was driven by the CM rather than cash-out reform. Under this sensitivity capacity margins are on average higher, and the impact of the policy packages on cash-out prices is lower.

However, even with a CM in place, policy considerations such as reducing PAR or introducing a RSP should enhance security of supply through improved interconnector response to scarcity events and activating greater demand side response as discussed in Section 5.3.3.

5.3. Value for consumers

5.3.1. Cost-benefit analysis

An annualised[56] cost-benefit analysis (CBA) was undertaken to assess the net impact on consumers of the proposed cash-out policy packages. A fundamental assumption made for this analysis is that all costs and benefits incurred by parties on account of cash-out reform will be passed onto consumers. In reality the extent to which the costs and benefits get passed through to customers will depend on the competitive dynamics of the market, but we have not attempted to model this effect given the inherent uncertainties out to 2030. The outcomes of this CBA for 2020 and 2030 are shown in Table 18 and Table 19 respectively.

The CBA is split into two groups of costs and benefits: those to producers (or producer surplus) and those accruing to consumers (consumer surplus). Some of the impacts assessed are direct outputs of the model whereas some are ex-post impacts that are layered onto the model outputs. The costs and benefits included in the producer surplus category are:

[55] There is minimal EEU in 2020, so 2030 results have been used here. These results include reductions in EEU from both voltage control and load disconnection.

[56] Each year modelled has a distinct CBA as opposed to a single cumulative CBA across the whole modelled horizon, for example as we are not tracking cumulative build of investment over time, but the level of investment that could potentially be supported in a given spot year.

- **Net imbalance charges (NIC) and RCRC**: these are direct outputs of the model and represent the costs of imbalance charges to parties and the redistribution of these charges through RCRC.
- **SO balancing and party hedging cost**: This represents the net change in the total costs of balancing the system. This is composed of the cost to the SO of accepting bids and offers and the costs to parties of hedging before Gate Closure (the cost of hedging is valued at the forward market price). Changes in these costs will occur through behavioural responses to changes in cash-out prices and reliability or forecasting improvements made by parties.
- **Payments for involuntary and voluntary disconnection**: This captures payments to consumers who are involuntarily disconnected and payments to industrial and commercial DSR where appropriate. These would in practice form part of the SO's costs of balancing but are split here for transparency.
- **Investment in new capacity**: This captures the costs of parties investing in additional capacity in response to the cash-out policy packages. We have analysed two forms of investment response – DSR (the results for which are presented in this section) and CCGT investment (the results for which are presented in Appendix C: 9.2. DSR is assumed to have no up-front investment costs but does have a utilisation cost captured in the SO balancing costs above. For the CCGT investment case, we subtract the 'infra-marginal' revenues: this is the benefit which is captured by parties operating in the wholesale markets, and would be captured regardless of cash-out reform. As not all costs associated with the investment are likely to be recouped through cash-out, it is not appropriate to assign all these costs to the packages.
- **Investment in reliability and forecasting**: Reliability and forecasting improvements are not endogenously captured as part of the model. However, changing cash-out incentives is likely to have a significant impact on the incentives to invest in these opportunities. We have undertaken analysis to assess the likely difference in investment incentives for reliability or forecasting improvements under the different packages. This presents the difference in investment cost compared to the Do Nothing case, where benefits represent a reduction in investment cost under a given package.
- **Price revenue benefit**: It is assumed that market participants pass all costs through to consumers. As such, this offsets all the costs incurred by market participants through increased prices for consumers.

Consumer surplus costs and benefits include:

- **Price revenue cost**: represents the costs passed through by market participants to consumers and directly offsets the price revenue benefit under producer surplus above.
- **Value of reduced lost load**: The packages are likely to improve security of supply for consumers and reduce lost load. Consumers place a value on lost load hence any reduction implies a benefit for consumers. The benefit to consumers of avoided voltage control and disconnection are valued at £6,000/MWh and £17,000/MWh respectively. Lost load is reduced through new capacity added in the model and improved interconnector response. Although interconnector flows are not captured endogenously within the model, it is assumed that given the spikiness of prices at times of system stress under the packages, these prices could be sufficient to incentivise interconnectors

to flow into GB subsequently averting some of the remaining lost load. We assume the same response from interconnectors in all packages[57].

- **Payment for involuntary and voluntary disconnection**: this captures the payments to consumers from the SO for disconnection services, netting off the cost to producer surplus above. These are payments for involuntary services in the case where consumers are cut-off in an emergency, and voluntary where consumers offer DSR services to the SO.
- **Value of voluntary disconnections**: Where DSR is disconnected, even if they receive payment for this, they still place an inherent value on lost load. This is captured here and is equal to the payment that they receive for this service.

The costs and benefits are summed to show the impact on consumers. This is quoted as a £/MWh cost for all customers, as well as a £/year impact on the average domestic customer bill. The £/MWh figure includes the costs and benefits passed on by parties, and the savings in unserved energy and voltage control. The £/year domestic bill figure does not include the savings in unserved energy and voltage control since these would not feature in the bill, but represent a benefit to domestic consumers in terms of enhanced security of supply.

Table 18 and Table 19 show the results of the cost benefit analysis for 2020 and 2030. This version of the CBA assumes that the long term capacity investment in response to the cash-out policy packages is delivered through greater DSR. We have also calculated the CBA assuming that long term capacity investment is delivered through investment in new generation plant (CCGT). These results are presented in Table 25 and Table 26 in Appendix C: 9.2. The net benefit of the cash-out policy packages is somewhat lower under this case, but the key messages are the same.

[57] This is limited to a reducing EEU by up to 5,125 MWh, which is sufficient to remove all EEU under Package P5 in 2030.

Table 18 CBA summary from domestic consumer perspective – DSR long term capacity, 2020

£m/year		2020				
		P1 LT	P2 LT	P3 LT	P4 LT	P5 LT
Producer Surplus	NIC	-107	144	-129	156	145
	RCRC	107	-144	129	-156	-145
	SO balancing and party hedging costs	1	0	2	-1	1
	Payments for involuntary disconnections	0	0	0	0	0
	Payments for voluntary disconnections	0	0	0	0	0
	Investment in new capacity	0	0	0	0	0
	Investment in reliability	-8	13	-9	13	13
	Price revenue benefit	7	-14	7	-13	-13
Consumer surplus	Price revenue cost	-7	14	-7	13	13
	Reduction in disconnection (new capacity)	0	0	0	0	0
	Reduction in voltage control (new capacity)	0	0	0	0	0
	Reduction in disconnection (interconnector)	0	0	0	0	0
	Reduction in voltage control (interconnector)	0	0	0	0	0
	Payment for involuntary disconnection	0	0	0	0	0
	Payment for voluntary disconnection	0	0	0	0	0
	Value of voluntary disconnection	0	0	0	0	0
Total consumer surplus (+ve = benefit)		-7	14	-7	13	13
Change in average £/MWh (-ve = benefit)		0.02	-0.05	0.02	-0.04	-0.04
Change in average domestic bill £/year (-ve = benefit)		0.07	-0.15	0.07	-0.14	-0.14

Note: totals may not sum due to rounding.

In 2020, the impact of the cash-out policy packages on consumers is relatively modest. This is a function of the relatively high starting capacity margin assumed in the input data. As we shall see below the impact is greater under a tighter capacity margin as shown in the 2030 results.

Variations in the costs and benefits from short term balancing incentives are modest. There is a small benefit in P1 and P3 associated with a slightly longer system. There is greater variation in the long term balancing incentives, with the dual price packages (P1, P3) leading to higher costs relative to DN, and the single pricing packages lower cost. This reflects the better alignment of party balancing incentives with underlying balancing costs. The impact of the long term capacity investment is negligible since the additional demand side response is rarely utilised (and hence the cost is very small), and there is no voltage control or unserved energy to reduce in the DN case. Likewise, there is no need for additional imports through interconnectors to reduce voltage control actions and unserved energy.

As a result the net impact on consumers is very small. Ranging from a £0.02/MWh net cost under packages P1 and P3 to a £0.05/MWh saving under P2. These variations are too small to be significant. It should be noted, however, that although the impact on consumers is small the distribution effects, as evidenced by the variations in NIC, are large which will impact on the competitive market dynamics.

The CBA indicates more significant costs and benefits of cash-out reform, and differences between packages, in the tighter system modelled for 2030. A key driver for this is an increase in the underlying energy balancing costs from £205m in 2020 to £753m in 2030. The NIC increases dramatically from around £107m in 2020 to £1.5bn by 2030. The impact of negative SSPs is a significant driver of these inflated balancing costs.

As was the case in 2020, the variations in balancing costs associated with short term balancing incentives are relatively modest associated with parties adopting different hedge positions. It should be noted that by 2030 a longer system does not necessarily lead to cost savings since the impact of negative bids will start to increase balancing costs significantly. The variations in the costs and benefits from long term balancing incentives vary significantly between packages. Under the dual price packages, the increased NICs, rising to £1.8bn under P3, could lead to inefficient investment to avoid the imbalance exposure. Under the single price packages, the NIC exposure is lower and this may help avoid over-investment.

In all packages, we see a similar cost associated with additional demand side response, since prices can rise to around £6000/MWh under the RSP in all cases, i.e. to a level that would activate most of the demand side response available. The costs of the demand side response are broadly in line with the savings in unserved energy, but there is a significant benefit in reduced cost of voltage control.

The net effect of the costs and benefits is that all packages show a benefit to consumers, ranging from £0.17/MWh in P1 and P3, and rising to £0.48/MWh in P5. The impact of more marginal PAR and VOLL costing are not that evident in the CBA results. This is because all packages have at least PAR 50 MWh and the RSP, which represent the biggest difference with DN and the impact of moving to PAR 1 MWh and introducing VOLL costing is modest within the resolution of the CBA. Greater differences can be seen in some of the other output metrics. Hence, it is important when evaluating the different cash-out policy packages to consider the CBA in conjunction with the other quantitative results, and qualitative arguments.

Table 19 CBA summary from domestic consumer perspective – DSR long term capacity, 2030

£m/year		2030				
		P1 LT	P2 LT	P3 LT	P4 LT	P5 LT
Producer Surplus	NIC	-233	461	-323	451	434
	RCRC	233	-461	323	-451	-434
	SO balancing and party hedging costs	9	-3	14	-9	13
	Payments for involuntary disconnections	0	0	0	-0.1	0
	Payments for voluntary disconnections	-16	-16	-16	-16.0	-16
	Investment in new capacity	0	0	0	0	0
	Investment in reliability	-33	66	-40	73	54
	Price revenue benefit	41	-47	43	-47	-50
Consumer surplus	Price revenue cost	-41	47	-43	47	50
	Reduction in disconnection (new capacity)	7	7	7	7	7
	Reduction in voltage control (new capacity)	60	62	63	61	63
	Reduction in disconnection (interconnector)	1	1	1	1	1
	Reduction in voltage control (interconnector)	31	31	31	31	31
	Payment for involuntary disconnection	0	0	0	0	0
	Payment for voluntary disconnection	0	0	0	0	0
	Value of voluntary disconnection	16	16	16	16	16
Total consumer surplus (+ve = benefit)		59	148	59	148	152
Change in average £/MWh (-ve = benefit)		-0.17	-0.43	-0.17	-0.43	-0.44
Change in average domestic bill £/year (-ve = benefit)		0.24	-0.61	0.25	-0.61	-0.64

Note: totals may not sum due to rounding.

5.3.2. Summary

Table 20 summarises the results from the CBA on the impact of the policy packages on customers. The net cost/benefit of packages is minimal in 2020, with small benefits for the single price packages. The net benefits are greater under the tighter system assumed in 2030, with the greatest benefit under P5.

Table 20 Influence of policy packages on cost to consumers – delta to DN

Package	2020		2030	
	Cost £/MWh	Impact on average domestic consumer bill £/yr	Cost £/MWh	Impact on average domestic consumer bill £/yr
P1	+£0.02	+0.07	-0.17	+0.24
P2	-0.05	-0.15	-0.43	-0.61
P3	+0.02	+0.07	-0.17	+0.25

Package	2020		2030	
	Cost £/MWh	Impact on average domestic consumer bill £/yr	Cost £/MWh	Impact on average domestic consumer bill £/yr
P4	-0.04	-0.14	-0.43	-0.61
P5	-0.04	-0.14	-0.44	-0.64
Notes	DN: £0.67/MWh	DN: £2.22/yr Based on average consumption of 3,300kWh/year	DN: £2.48/MWh	DN: £7.22/yr Based on average consumption of 3,300kWh/year

5.3.3. CM sensitivity

Table 21 and Table 22 show the results for the CBA under the CM sensitivity for 2020 and 2030 respectively. The single pricing packages (P2, P4 and P5) still show net benefits to consumers but these benefits are less than in the case without the CM, since it is the CM rather than cash-out reform that drives the additional investment in capacity that reduces EEU.

Table 21 CBA summary from domestic consumer perspective – with CM scenario – 2020

£m/year		2020				
		P1 LT	P2 LT	P3 LT	P4 LT	P5 LT
Producer Surplus	NIC	-113	139	-139	152	138
	RCRC	113	-139	139	-152	-138
	SO balancing and party hedging costs	1	0	2	1	0
	Payments for involuntary disconnections	0	0	0	0	0
	Payments for voluntary disconnections	0	0	0	0	0
	Investment in new capacity	0	0	0	0	0
	Investment in reliability	-7	12	-9	11	12
	Price revenue benefit	7	-12	7	-12	-13
Consumer surplus	Price revenue cost	-7	12	-7	12	13
	Reduction in disconnection (new capacity)	0	0	0	0	0
	Reduction in voltage control (new capacity)	0	0	0	0	0
	Reduction in disconnection (interconnector)	0	0	0	0	0
	Reduction in voltage control (interconnector)	0	0	0	0	0
	Payment for involuntary disconnection	0	0	0	0	0
	Payment for voluntary disconnection	0	0	0	0	0
	Value of voluntary disconnection	0	0	0	0	0
Total consumer surplus (+ve = benefit)		-7	12	-7	12	13
Change in average £/MWh (-ve = benefit)		0.02	-0.04	0.02	-0.04	-0.04
Change in average domestic bill £/year (-ve = benefit)		0.08	-0.13	0.08	-0.13	-0.14

Note: totals may not sum due to rounding.

Table 22 **CBA summary from domestic consumer perspective – with CM scenario - 2030**

£m/year		2030				
		P1 LT	P2 LT	P3 LT	P4 LT	P5 LT
Producer Surplus	NIC	-195	488	-242	510	486
	RCRC	195	-488	242	-510	-486
	SO balancing and party hedging costs	2	-10	1	-29	-11
	Payments for involuntary disconnections	0	0	0	0	0
	Payments for voluntary disconnections	0	0	0	0	0
	Investment in new capacity	0	0	0	0	0
	Investment in reliability	-28	64	-33	84	64
	Price revenue benefit	25	-54	32	-56	-52
Consumer surplus	Price revenue cost	-25	54	-32	56	52
	Reduction in disconnection (new capacity)	0	0	0	0	0
	Reduction in voltage control (new capacity)	0	0	0	0	0
	Reduction in disconnection (interconnector)	0	0	0	0	0
	Reduction in voltage control (interconnector)	1	1	1	1	1
	Payment for involuntary disconnection	0	0	0	0	0
	Payment for voluntary disconnection	0	0	0	0	0
	Value of voluntary disconnection	0	0	0	0	0
Total consumer surplus (+ve = benefit)		-24	55	-31	57	53
Change in average £/MWh (-ve = benefit)		0.07	-0.16	0.09	-0.16	-0.15
Change in average domestic bill £/year (-ve = benefit)		0.24	-0.52	0.31	-0.53	-0.50

Note: totals may not sum due to rounding.

5.4. Competition and sustainability impacts

By sharpening cash-out prices, the cash-out policy packages are expected to disadvantage independent parties to the greatest extent which could have a negative impact on competition. This is primarily due to the fact that historically, they have been the poorest balancers. However, the inclusion of single pricing appears to offset these dis-benefits for independent suppliers, and reduces them for independent wind generators. Ultimately, competition is likely to deliver the best value for consumers when it is revealing the true underlying costs. Higher imbalance costs for intermittent generators could be compensated for through higher subsidies and hence the cash-out packages need not necessarily be detrimental to investment in low carbon generation, and by revealing the true costs of balancing this should lead to a lower cost outcome for consumers in the long run.

Table 23 outlines the impact of each policy package on competition.

Table 23 Influence of policy packages on competition

Package	Assessment	Opportunity cost, 2020 / 2030 Relative to DN (£/MWh)	
		Independent wind	Independent suppliers
P1	• Least marginal PAR of policy packages where more marginal prices likely to impact negatively independent parties with poorer balancing characteristics to the greatest extent • Relatively high long term investment response increases margins and reduces the inflating effect of the RSP, where the RSP might impact independent parties with poorer balancing characteristics to the greatest extent • Dual pricing policy will not offset increase in marginality and inflating effect of the RSP for independent parties	+1.5 / +3.8	+1.2 / +2.8
P2	• Most marginal PAR of policy packages • Marginal PAR susceptible to system pollution and price distortions; greatest risk that SSP may be set by rogue negative bids[58] • Relatively high long term investment response will reduce the inflating effect of the RSP • Single pricing will mitigate marginality consequences for independents, particularly independent suppliers; but sensitive to forecast error correlation for independent wind generators	-0.7 / +0.5	-4.1 / -7.7
P3	• Most marginal PAR of policy packages • Marginal PAR susceptible to system pollution and price distortions; greatest risk that SSP may be set by rogue negative bids • Highest long term investment response reduces the impact of VoLL and the RSP • Dual pricing policy will not offset increase in marginality and inflating effect of VoLL and the RSP for independent parties	+1.8 / +5.6	+1.5 / +4.5
P4	• Least marginal PAR of policy packages • Lowest long term investment response will have least mitigating impact on costing demand control actions and RSP • Single pricing will mitigate marginality consequences for independents, particularly independent suppliers; but sensitive to forecast error correlation for independent wind generators	-0.8 / +1.4	-3.9 / -7.4
P5	• Most marginal PAR of policy packages • Marginal PAR susceptible to system pollution and price distortions; greatest risk that SSP may be set by rogue negative bids	-0.6 / +1.5	-3.6 / -8.1

[58] E.g. from wind generators bidding significantly lower than the opportunity cost of their subsidy support, although the recent introduction of the Transmission Constraint Licence Condition should improve the cost reflectivity of wind bidding and alleviate some of the potential for this to occur.

Package	Assessment	Opportunity cost, 2020 / 2030 Relative to DN (£/MWh)	
		Independent wind	Independent suppliers
	• Moderate long term investment response will reduce impact of VoLL and the RSP • Single pricing will mitigate marginality consequences for independents, particularly independent suppliers; but sensitive to forecast error correlation for independent wind generators		
Notes		DN: 5.7 / 13.6	DN: 6.5 / 16.3

Sustainability will be impacted by the modelled cash-out packages in two main ways:

- Exposure to higher imbalance charges may encourage part-loading of thermal plants to mitigate risk of forced outages from cold-starts leading to slightly higher emissions, and
- For a given subsidy level, the higher cost of imbalance for independent wind parties relative to packages with lower PAR or single pricing (P2/4/5) might reduce bankability and discourage low carbon investment.

The impacts on the investment in low carbon generation assume subsidy levels remain unchanged to DN. As mentioned above, where subsidy levels are adjusted in response to more reflective imbalance charges, the impact on investment in low carbon generation need not be impacted by cash-out reform.

6. CONCLUSIONS

In the absence of cash-out reform, the changing generation mix under a potentially tightening capacity margin, will likely drive significant increases in the costs of energy balancing over the next two decades. For example, under the Do Nothing case Gross Imbalance Volumes could rise from ~30 TWh/year at present to ~80 TWh/year by 2030 due primarily to increasing amounts of renewables on the system; with the overall cost of energy balancing to the consumer[59] potentially doubling by 2020 (from ~£74M/year) and increasing by a factor of ten to 2030. The costs of system balancing, such as locational balancing, could also rise dramatically over this period but this was not a focus of this study.

The additional energy balancing costs will result in higher imbalance charges for out of balance parties (for example, imbalance opportunity costs[60] for independent wind generators could rise from ~£1/MWh[61] today under DN to over £5/MWh in 2020 and over £10/MWh in 2030); although under current rules the full extent of the additional costs may not be reflected in cash-out prices. The modelling suggests that System Buy Prices (SBPs) will rise over time, but that after 2015 System Sell Prices (SSPs) will start to fall as bids from subsidised low carbon generation are captured within the cash-out price calculation. By 2025, the average SSP is expected to be negative. This will result in a greater spread in cash-out prices which is expected to influence player behaviour. The risk of being exposed to potentially very high negative SSPs for being long may become as material as the risk of exposure to very high SBPs for being short, and thus the current incentive to adopt a systematically long position may change. For example, the modelling suggests that greater marginality in cash-out prices reinforces incentives to go long in 2020, but by 2030 the effect is broadly reversed, albeit with variations across the year. Under single pricing, the incentives are different again since parties are rewarded for being out of balance in the opposite direction to the system.

Increasing the marginality of PAR, including the RSP and costing demand control actions appears to be justified in terms of signalling the value of peak energy and flexibility, and possibly stimulating additional investment in demand side response and new generating capacity under a tight system.

For example, the incremental impact of moving from PAR500 to P50 (excluding the effect of the RSP and costing demand control) adds around £10/MWh to average SBP (when it is the main price) in 2020 and £15/MWh in 2030. The combined impact of more marginal PAR1, RSP and costing of demand control actions under P3 and P5 leads to a much sharper SBP when it is the main price; ~£15/MWh higher on average in 2020 and ~£27/MWh higher in 2030, under the core scenario without the CM, compared to DN.

The modelling suggests that under P5 the impact of the cash-out reform on market prices in a tight market in 2030[62] is equivalent to a price signal which could in theory support around 3 GW of additional capacity. These reforms to cash-out should also encourage greater imports into the GB market under conditions of system stress, and provide effective signals for the dispatch of

[59] As defined in Appendix B: 8.2.
[60] We use the term here to represent the loss to a party that is incurred by being out of balance as opposed to settling its entire position in the wholesale energy market.
[61] Per MWh of credited energy generated or supplied.
[62] In the absence of the Capacity Mechanism.

flexible generation and demand side response. The combined impact of the cash-out reforms should reduce the risk of load disconnection or voltage control to very low levels.

The modelling suggests that the current dual pricing approach, with a wide (and expected widening) spread between SBP and SSP, leads to imbalance charges which on average are greater than the underlying costs of balancing the system. Sharpening cash-out prices should signal the value of peak energy but compound this 'over-charging' for imbalances under normal conditions. This could lead to inefficient investment to improve private balancing performance which cannot be justified in terms of savings in energy balancing costs at the system level. Packages with single pricing appear to align incentives for parties to invest in their own balancing improvement much more closely with the overall system-wide benefits from this investment, in terms of reduced balancing costs, and in the long term may lead to more efficient outcomes. The incentives to make provisions for covering peak conditions are the same as for the equivalent dual pricing options, but the incentives to balance under normal conditions are weaker as a result of the potential reward from being out-of-balance in the opposite direction to the system.

The differences between the dual and single price packages are also reflected in the distributional analysis. For independent players, who traditionally have been weaker balancers, the impact of sharper cash-out prices would be to increase balancing costs. However, the modelling of packages with single pricing suggests that the disbenefit to independent players of sharper cash-out price signals could be offset by removing the cost of dual pricing. This is particularly the case for independent suppliers. For independent wind generators the relative benefits of single pricing do depend, to some extent, on the degree of correlation in their forecast errors, and as a result the frequency with which wind generators are out of balance in the opposite direction to the system.

The modelling suggests that consumers would be net beneficiaries of all of the cash-out policy packages in a system with tight capacity margins (up to ~£0.5/MWh after accounting for the benefits of a reduction in unserved energy), and any additional costs in a well-supplied system would be small or neutral. Given the additional benefits to security of supply, not all of which could be quantified, reforms to cash-out seem to be warranted. The negative distributional impacts of sharper cash-out prices could be mitigated through single pricing, which suggests that Packages P2, P4 and P5 may be preferred.

The modelling suggests that differences between these three packages are relatively modest given that the move to at least PAR50 and the introduction of the RSP, common to all packages, marks the biggest difference with the Do Nothing case. However, not all of the differences can be quantified. P5 would likely provide the greatest benefits to security of supply, primarily as a result of the most significant price signal for new investment due to both PAR1 and costing of demand control actions. There are some limited residual risks associated with PAR1 due to system pollution or 'rogue' bids (e.g. from subsidised generators bidding significantly below the opportunity cost of their subsidy) occasionally setting the cash-out price. P4 with PAR50 would help mitigate against this, but at the expense of less cost-reflective pricing and a weaker investment signal compared to P5.

The analysis in this report has primarily focused on the impact of the cash-out policy packages in isolation of other policy measures. The introduction of the CM under EMR may be a more important driver for investment in new capacity (demand side response or new generating capacity) than cash-out reform. It is important to ensure not to double count the benefits of greater security of supply across the two reform programmes. However, cash-out reform still has a role to play in signalling efficient plant dispatch, utilisation of demand side response, and ensuring efficient flows on interconnectors. The modelling suggests that customers remain net beneficiaries of the single pricing packages (P2, P4, P5) even with a CM in place. Hence, reform to cash-out can go hand in hand with the introduction of the CM. Provided that participants know of the changes to cash-out before offering into the first capacity auctions, and offer competitively, customers should not necessarily be exposed to higher costs from introducing both cash-out reform and the CM. It is also important to note that the risk of exposure to non-delivery penalties under the CM may start to influence player behaviour as much as cash-out risk. In turn this could affect the average system balance and cash-out prices, the modelling of which was outside the scope of this study. Further analysis in this area may be required.

7. APPENDIX A – MIP REGRESSION MODEL

A regression model was developed to form a structural relationship between independent simulated and endogenous variables in the cash-out model, and the dependent variable MIP. It has the following features:

- Linear form with quadratic terms on reserve margin to capture the non-linear response that forward prices have to a tightening system
- Separate cash-out price and reserve margin coefficients for buy and sell periods
- Purely contemporaneous independent and dependent variables
- Coefficients generated on a monthly basis using half-hourly historic data dating back to 5/11/2009 (~4,400 observation per month)
- Generalised least squares (GLS)

$$MIP_t = \beta_1 SBP_t + \beta_2 SSP_t + \beta_3 demand_t + \beta_4 RM_{buy,t} + \beta_5 RM^2_{buy,t} + \beta_6 RM_{sell,t} + \beta_7 RM^2_{sell,t} + \beta_8 wind_t + \beta_9 gas_t + \beta_{10} carbon_t + intercept_t$$

The coefficients on each of these terms can be found in Table 24. Coefficients significant to a 0.05 level are highlighted in bold.

Table 24 Regression model coefficients

Variable	Units	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Intercept	-	-2.4	2.0	3.3	**-6.8**	-2.6	-1.0	**-11.9**	**-8.7**	3.2	**17.1**	-0.6	**-18.8**
SBP	£/MWh	**0.0**	**0.1**	**0.1**	**0.1**	**0.1**	**0.0**	**0.1**	**0.0**	**0.1**	**0.1**	**0.1**	**0.1**
SSP		**0.2**	**0.1**	**0.1**	**0.3**	**0.1**	**0.1**	**0.2**	**0.1**	**0.2**	**0.1**	**0.2**	**0.2**
Demand	GWh	**1.4**	**1.3**	**1.2**	**1.3**	**1.3**	**1.2**	**1.1**	**1.1**	**1.4**	**1.7**	**1.6**	**1.9**
RM_{buy}	GW	**-1.3**	**-1.9**	**-2.3**	0.0	**-0.8**	**-0.3**	0.2	**-0.4**	**-1.0**	**-1.9**	**-2.3**	**-1.9**
RM^2_{buy}		**0.0**	**0.1**	**0.1**	**0.0**	**0.0**	0.0	**0.0**	0.0	**0.0**	**0.1**	**0.1**	**0.1**
RM_{sell}		**-1.6**	**-1.8**	**-1.6**	**-1.1**	**-0.7**	**-0.5**	**-0.5**	**-0.6**	**-0.9**	**-1.3**	**-2.2**	**-2.0**
RM^2_{sell}		**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	0.0	0.0	0.0	**0.0**	**0.0**	**0.1**	**0.1**
Wind	MWh	0.0	0.0	**0.0**	**0.0**	**0.0**	0.0	**0.0**	0.0	**0.0**	**0.0**	**0.0**	**0.0**
Gas	£/MWh	**0.9**	**1.3**	**1.4**	**1.3**	**1.3**	**1.1**	**1.6**	**1.7**	**0.9**	0.1	**1.1**	**1.6**
Carbon		**0.8**	0.2	**0.3**	**0.5**	**0.6**	**0.6**	**0.6**	**0.6**	**0.4**	**0.7**	0.1	**0.5**

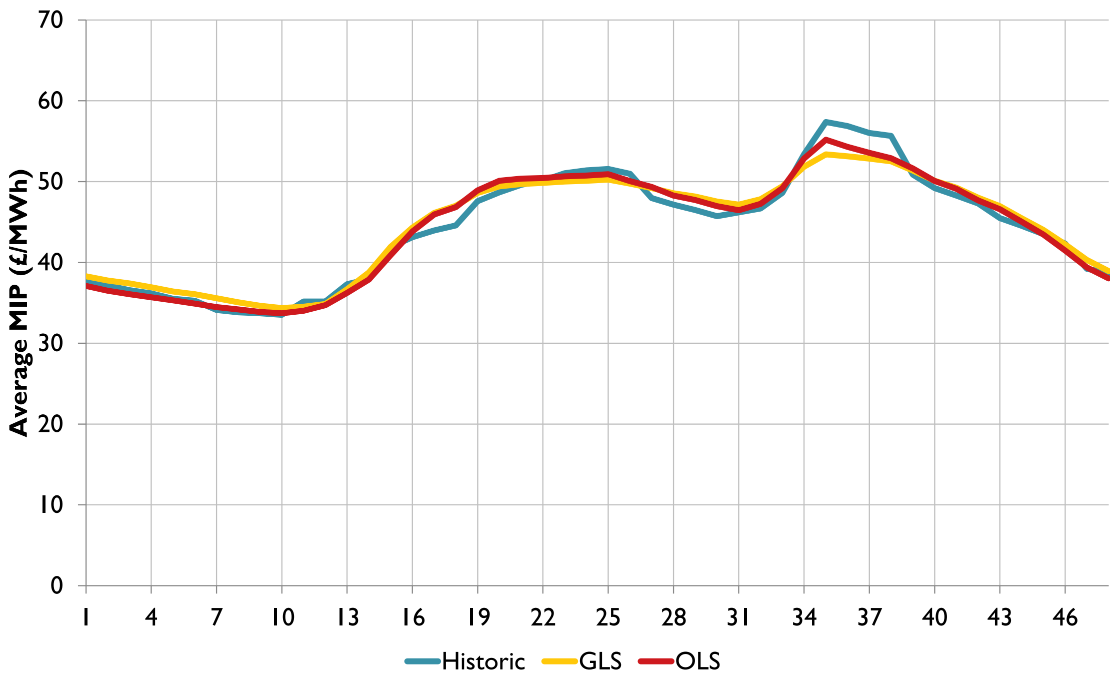
Of all the available variables for inclusion, NIV, coal and oil were omitted as their inclusion did not enhance the explanatory power of the model. Furthermore, in the case of NIV, there was concern that the inclusion of demand, reserve margin and NIV would over specify the influence of demand effects. Considering the cash-out signal is already provided by the magnitude and directionality of the relevant cash-out price, it was considered appropriate to allow the omission of NIV. Maintaining gas and carbon in the model was considered important given that gas has historically been (and is projected to continue to be) the fuel on margin and carbon will become increasingly important with the increase in the Carbon Price Floor.

Other functional forms[63] were considered including a log-log form. The linear form was adopted as it was better suited to the increasing incidence of negative price periods than the log-log equivalent. A purely contemporaneous (i.e. a single time instance for all variables) model was adopted as introducing lagged variables would assume that sequential time periods in the model outputs have serial dependency, where in actual fact they are modelled discretely. Furthermore, testing combinations of lagged variables was found to reduce the explanatory power of the model.

A Generalised Least Squares (GLS) solution was preferred to the Ordinary Least Squares (OLS) solution as GLS is typically better at accounting for the serial correlation of variables.

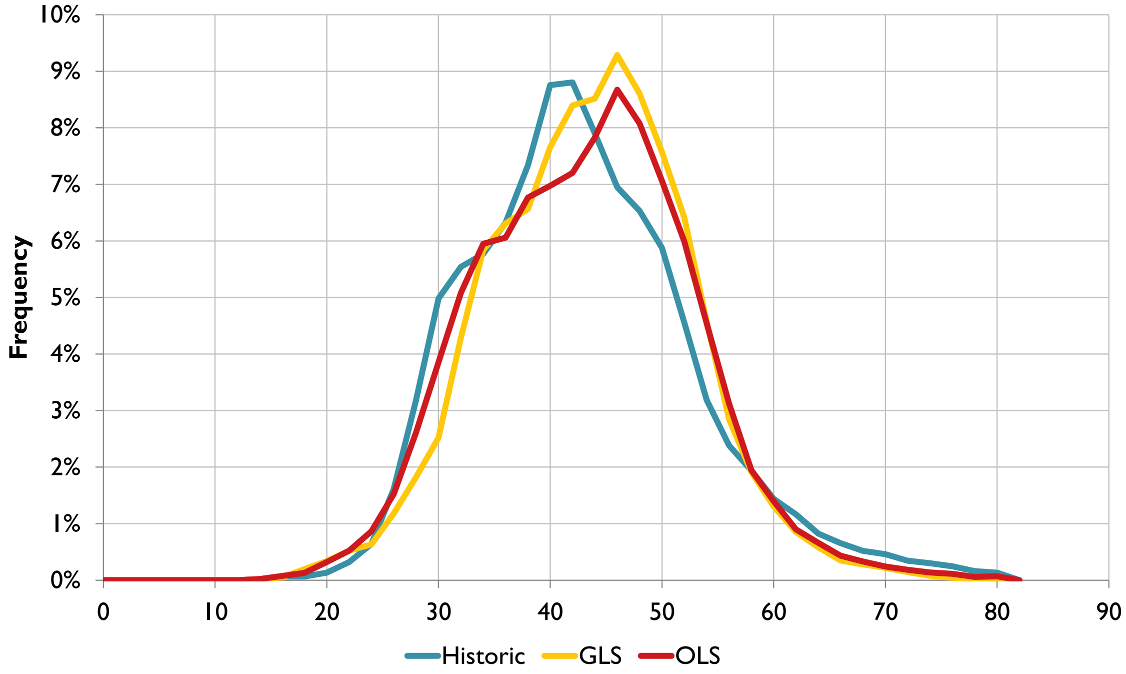
Fitting the above coefficients to the historic input information yields the following outcomes (Figure 53 and Figure 54). Coefficients generated using both the GLS and OLS solutions have been included as a point of comparison.

Figure 53 Regression model fit with historic data – average across the day



[63] I.e. the underlying mathematical structure of the regression model, in terms of whether the regression model variables exhibit linear, quadratic, exponential or other properties.

Figure 54 Regression model fit with historic data – distribution

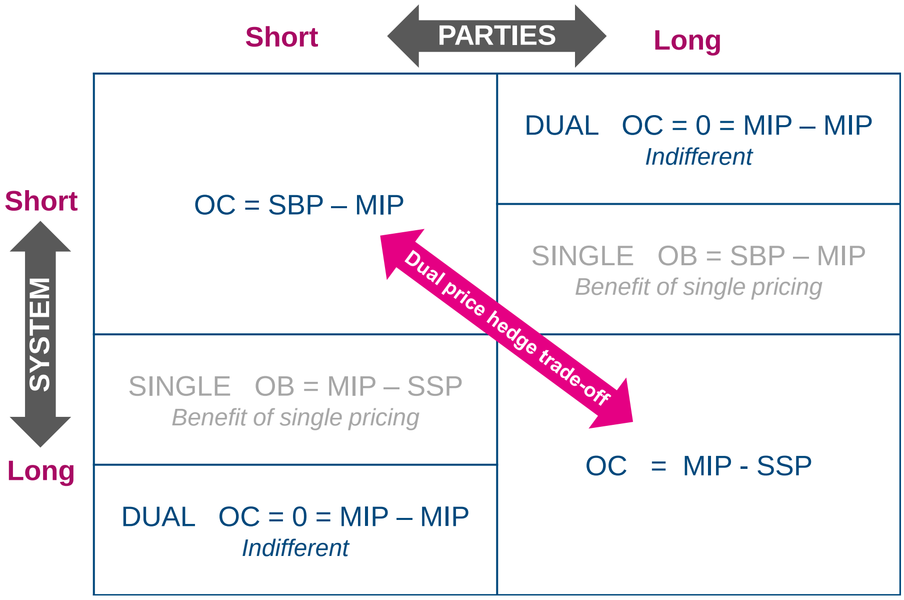


8. APPENDIX B – ADDITIONAL CONCEPTS

8.1. Incentives for hedging

Figure 55 outlines the opportunity cost (OC) trade-off to parties of being out of balance according to the direction of system imbalance. Under dual pricing, when determining a hedging strategy, each party is simply trying to minimise the OC of being out of balance in the same direction as the system. They are indifferent to being out of balance in an opposing direction, where they pay or receive the market price.

Figure 55 Imbalance opportunity cost to parties depending on the direction of party and system imbalance under dual pricing policies



For each party type, hedging to minimise their opportunity cost depends on:

1. How often the overall system NIV is short versus long
2. The actual opportunity cost in each of these cases – i.e.: the spread in SBP / SSP to MIP when the system is short versus long
3. The frequency and volume of imbalance for each party in each quadrant position, both with and without the hedge
4. The impact of the party's hedged position on overall system values: NIV, SBP, SSP and MIP

Strategies are largely dependent on the physical properties of the party's portfolio. For instance, portfolios that are comprised mainly of thermal generating plant will have a greater propensity to hedge long as they are focused primarily on the risk of a forced outage, resulting in infrequent but large short positions and exposure to high SBPs. For independent suppliers and wind parties the distribution of imbalance is broadly symmetrical around short and long imbalances.

Hence at the extremes; if hypothetically the system is typically:

- short and buy spreads are much greater than sell spreads (i.e.: SBP-MIP >> MIP-SSP) a party would want to hedge long
- long and buy spreads are much less than sell spreads (i.e.: SBP-MIP << MIP-SSP) a party would want to hedge short

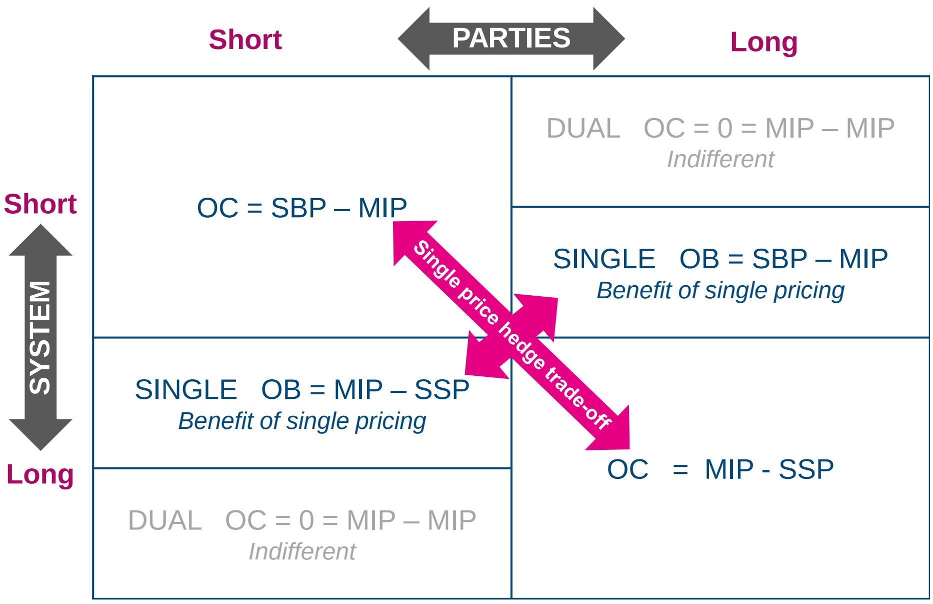
However, a party which over-hedges in any situation will at some point end up increasing its opportunity cost again. For example, if it is hedging too long it will start to increase the frequency and volume that it is long while the system is long (thus incurring more of the MIP-SSP opportunity cost) rather than just being long when the system is short to reduce the SBP-MIP OC. Therefore, there is an optimum position for a party to minimise its expected OC, all else being equal.

This is further complicated by the fact that each party's independent hedging positions affect the system position (particularly the case for larger VIU parties), and hence the opportunity cost of all parties. This is exacerbated further if a party's hedging decision actually starts to flip the typical system NIV and the frequency with which the party is short/long relative to the overall system imbalance.

Packages with single pricing

Under packages with single pricing, in addition to the decision to hedge to minimise the opportunity cost of being out-of-balance in the same direction as the system (as per dual pricing) there is now also the potential to gain an 'Opportunity Benefit' (OB) of being out of balance in the opposite direction to the system (rather than just being indifferent as under dual pricing). Figure 56 outlines the trade-offs.

Figure 56 Imbalance opportunity cost to parties depending on the direction of party and system imbalance under single pricing policies



All else being equal, the opportunity cost of a party under single pricing policies will be lower than under dual pricing policies. This is because the same occurrences of being out of balance in an opposing direction to the system will result in a benefit, whereas under dual pricing policies, parties are indifferent (or have an opportunity benefit of zero).

For parties hedging long already, the cost of the hedge is effectively reduced as in addition to minimising the opportunity cost of short/short occurrences these parties receive an opportunity benefit of SBP-MIP when they are long and the system is short. This will happen more often for these parties as a result of the long hedge. The contrary is true for parties that already adopt a short hedge under dual pricing policies.

Hence, where the size of buy side spread is much greater than the sell side spread (SBP-MIP >> MIP-SSP) a single party with a propensity to hedge long is likely go longer under single pricing, all else being equal. This is particularly true for party types who are more exposed to being short such as independent thermal generators or portfolios with a large thermal component.

However, whether these parties would do this in practice also depends on the other parties' decisions and the overall system impacts of these. For example, if under single pricing all other parties (outside of the independent thermal generators) wanted to go longer, the overall system is shifted longer on average as a result. Even without shifting their position the independent thermal generators' opportunity costs have now changed and their default long hedge may even be too long to minimise their opportunity cost, and as a result they may prefer to go slightly shorter (assuming that their shift has negligible impact on the final system equilibrium).

For independent suppliers and wind parties the opportunity cost of minimising their position needs to consider the same general factors as dual pricing but with the additional dimension of the potential to receive an opportunity benefit when the party imbalance is in the opposite direction to the overall system.

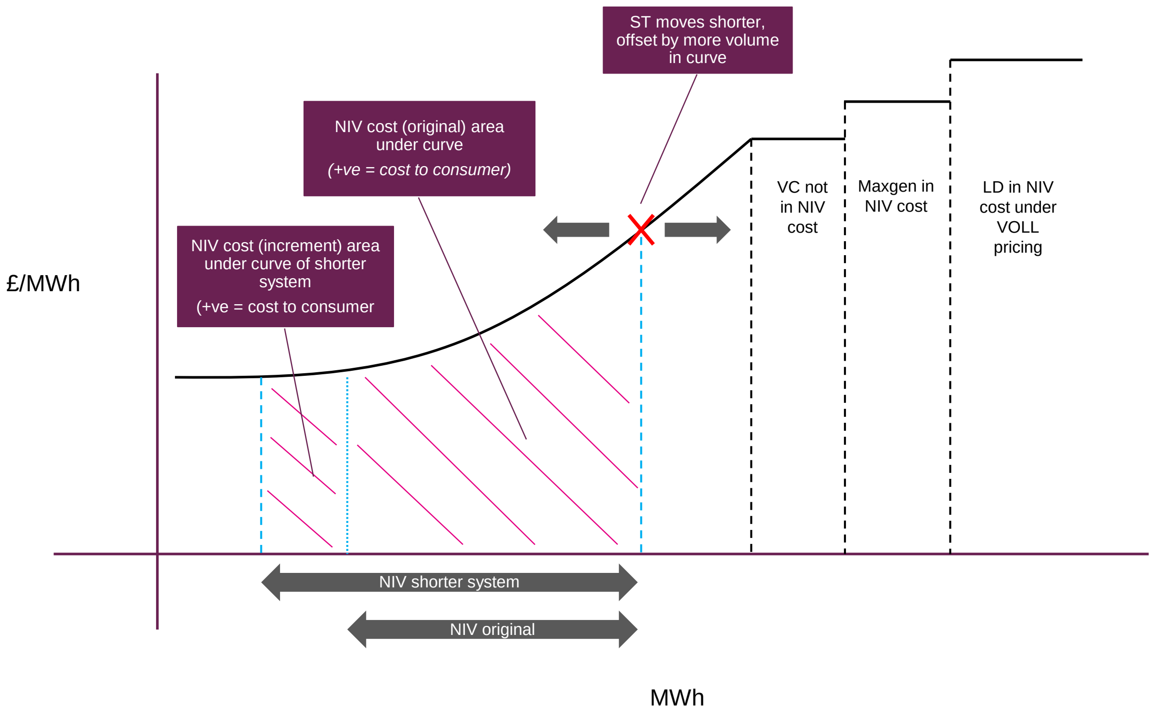
A key caveat to the above under single pricing is if a party type is becoming the main driver of the direction of the overall system NIV. This could potentially become the case for independent wind parties in the longer term, if they were subject to have a high degree of production imbalance correlation (see Section 4.4.3). Under these circumstances, even with a hedge they are less and less likely to be out of balance in the opposite direction to the system to gain from any opportunity benefit. The focus for these party types is then more on minimising their opportunity cost as per dual pricing policies.

8.2. NIV 'consumer cost of balancing'

The standard approach to calculating the cost of balancing is to take the area under the offer or bid balancing curve for the given NIV. The sign convention reflects the costs to the System Operator with offers being a cost and bids a benefit (i.e. incoming cashflow) unless a negative bid has been made and hence this becomes a cost (outgoing cashflow to the party from the SO). This is outlined in Figure 57 and Figure 58 below.

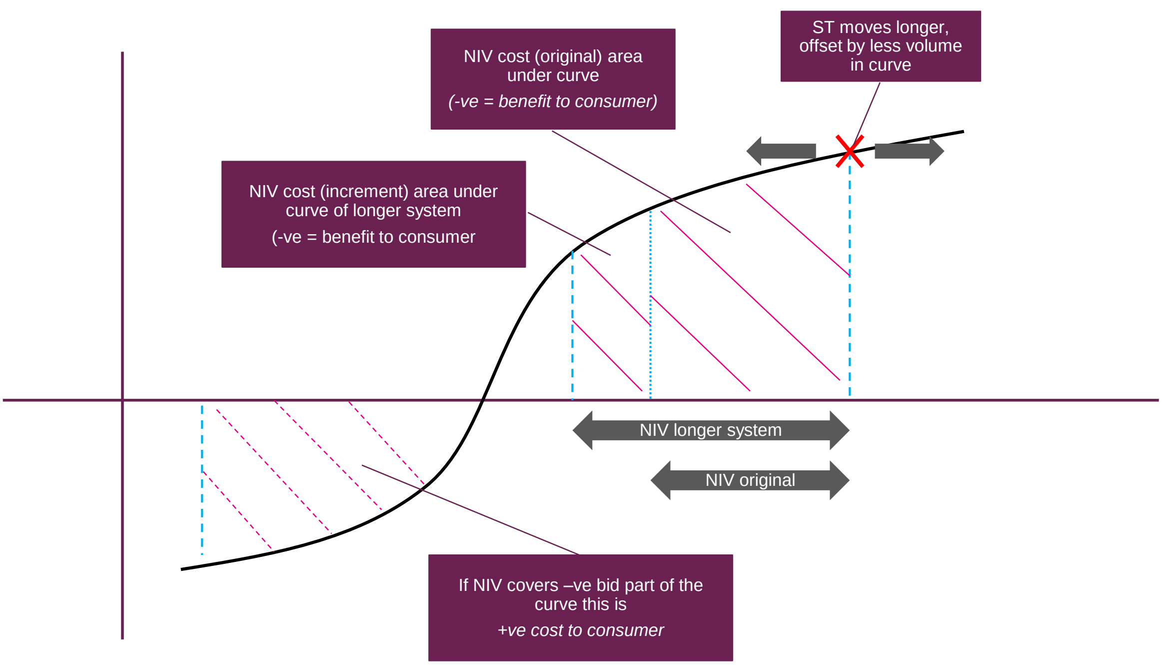
As parties shift their position and the system becomes longer or shorter the costs of balancing change accordingly. In the absence of negative bids this would imply an increasing benefit to the consumer (i.e. due to incoming cashflow to the SO) of a longer system.

Figure 57 Offer curve – standard calculation of cost of balancing in a settlement period



Note that on the offer side for the purposes of calculation the area under the curve, VC (voltage control) is not included in the cost as it is deemed effectively deemed to be a 'free balancing' option to the SO (the ultimate cost to the consumer of having more or less voltage control on the system are however captured separately in the CBA in Section 5.3.1).

Figure 58 Bid curve – standard calculation of cost of balancing



However, the standard approach does not take into account the hedging cost of parties as they go longer. The longer the system goes the increasing level of the hedge cost (i.e. contracting for more energy in the wholesale market ahead of time which may not be needed), which would ultimately be passed through to consumers.

To provide a better measure of the true cost to consumers of balancing it is necessary to account for both the costs to the SO and the costs of hedging. *N.b. this metric is the same as the "NIV opportunity cost" used for assessing long-term balancing incentives in Sections 4.3.4 and 8.3.*

On the offer side (see Figure 59) this is done by considering the cost of energy (at the MIP) that would have to be purchased anyway if the system was short, within the overall balancing costs, i.e. the difference between the area under the offer curve and the MIP cost associated with the NIV volume is effectively the 'distressed cost' of having to purchase energy through the BM rather than the wholesale energy market.

Conversely on the bid side (see Figure 60), as the system moves longer more energy is contracted for ahead of time at the market price than is ultimately needed, and hence the difference between the MIP cost and the area under the bid curve effectively represents the 'cost to consumers of spill energy'.

Using this approach, the cost of balancing to consumers can only be a positive cost regardless of whether the system is long or short. It can only be zero in a given settlement period if the system is perfectly in balance.

Figure 59 Offer curve – 'consumer cost' of balancing

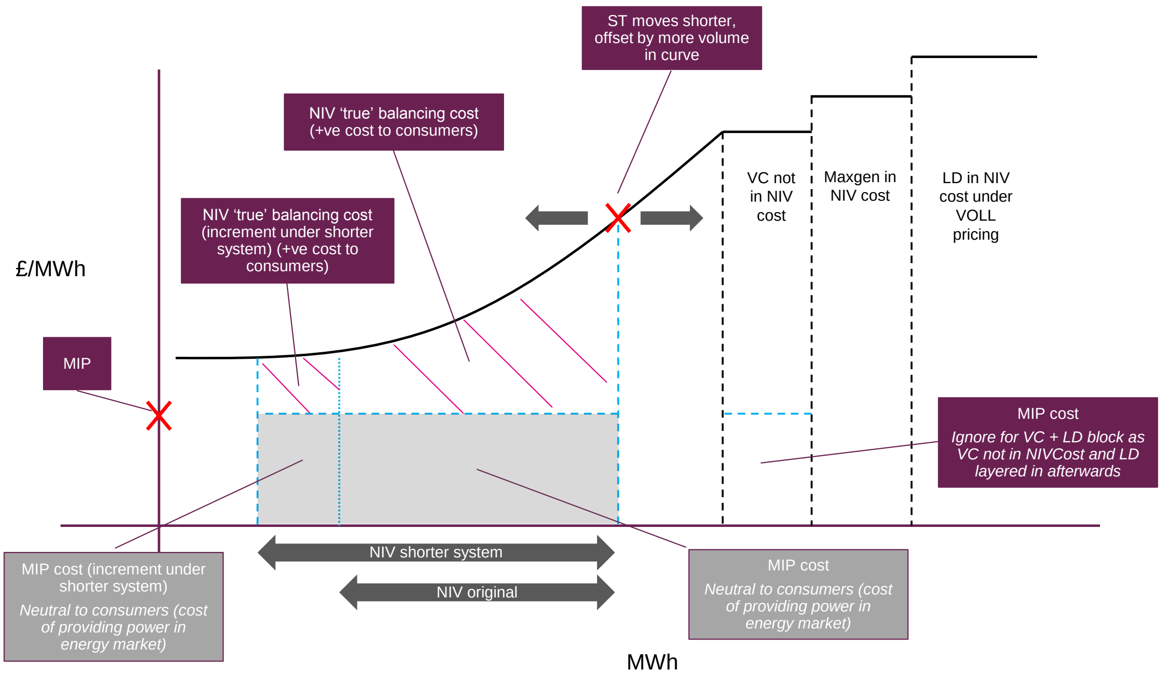
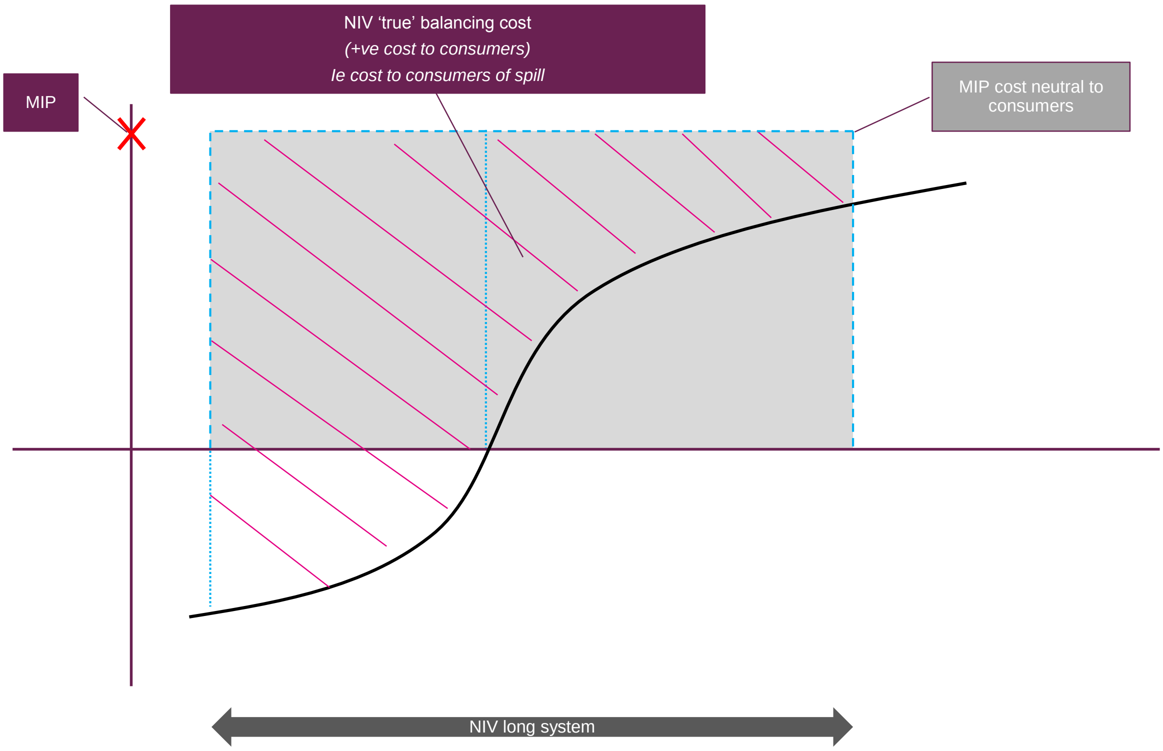


Figure 60 Bid curve – 'consumer cost' of balancing



8.3. Approach to long-term balancing incentives

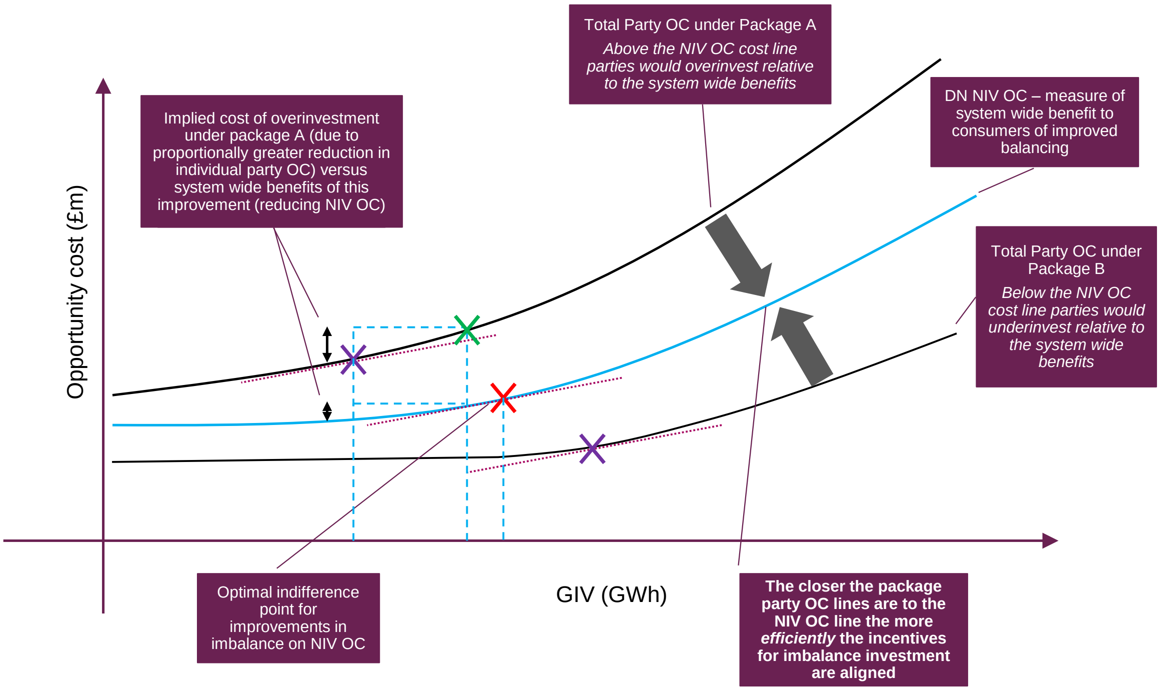
In order to quantify the effect of long-term balancing incentives, we attempted to estimate the level of balancing improvement that parties would invest in based on the savings that they could achieve.

For a typical level of system imbalance, we calculate the indifference point on the NIV opportunity cost curve as outlined in Figure 61 below i.e. the value of lower or higher Gross Imbalance Volumes at the system level, and assume that this is reflective of the cost of improving balancing performance. This is marked by the red X in Figure 61.

By matching this gradient to the opportunity cost curves for the parties under the packages we can then estimate the level of imbalance where parties are indifferent to investing further to improve their balancing performance or taking the additional cash-out exposure. This is marked by the purple Xs in Figure 61.

In the stylised example, Package A represents a package where the party imbalance opportunity cost is greater than the underlying NIV opportunity cost. Although parties are incentivised to reduce their imbalance volumes, the cost of this investment is greater than the savings in NIV cost. The green X in Figure 61, represents the starting GIV under package A, whilst the purple X reflects the GIV that would be achieved after investment is taken to reach the same indifference gradient as the NIV opportunity cost curve (the red X). However, the implied cost of investment from the reduction in party opportunity costs as you move down the package A curve from the starting GIV to the indifference point (green X -> purple X) is larger than the equivalent NIV opportunity cost reduction.

Figure 61 Stylised example of long term imbalance incentives trade off



Stylised Package B has party opportunity cost below the NIV opportunity cost. We do not have any examples of this in the packages that were modelled, but Package B could be representative of a single price package with PAR of 500 MWh and no RSP or VoLL. In this example, parties are incentivised to invest less in balancing performance, but the additional costs to the system are greater than the avoided investment.

9. APPENDIX C – ADDITIONAL RESULTS

9.1. Distributional effects of improved plant reliability and forecasting

Section 4.3.4 outlined the aggregate system effects of parties responding to incentives to invest in improved balancing. However, there are also distributional effects among parties to consider such as:

- The extent to which individual parties invest in improved balancing will differ according to their individual incentives, and
- There are distributional cashflow effects following this investment in the allocation of NIC and RCRC, much of which will not directly impact domestic consumers but does have implications for competition.

To explore this, a uniform 5% improvement to the imbalance deviation of parties (consumption and production accounts) was modelled and the distributional outcomes assessed. Independent suppliers and wind parties were modelled to yield the greatest benefit from improvements to imbalance deviation (Figure 62 and Figure 63). Historically, these parties have had the greatest variation in imbalance due to the nature of their customers/assets and the reduced portfolio benefit effects that characterise the larger integrated players. With substantial growth in wind capacity on the system, it is intuitive to consider that improvements in location-specific wind forecasting services may improve. The benefit of reduced imbalance exposure is one likely driver to pay for innovation toward such improvements.

Figure 62 Party-level savings from a 5% improvement in plant reliability and forecast accuracy for each policy package, 2020; -ve values represent savings to the party and values £/MWh is in reference to total credit energy volumes

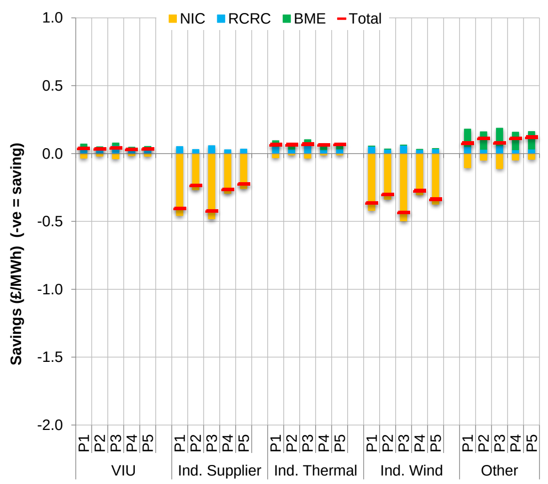
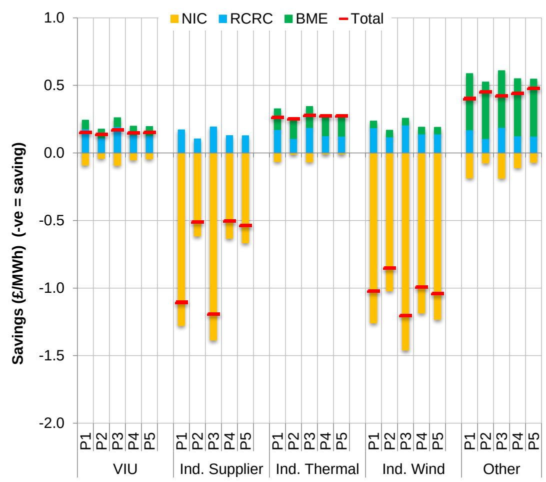


Figure 63 Party-level savings from a 5% improvement in plant reliability and forecast accuracy for each policy package, 2030



By contrast, the modelling suggests that improvements in forecasting accuracy across the system result is a net cost to parties that have historically been better at balancing their position. Although all parties benefit from a reduction in their direct imbalance costs, the larger integrated players lose out more from reduced Balancing Mechanism revenues and rebates through RCRC. Thus with improved balancing there is a transfer of surplus from those parties with typically good balancing characteristics to those that have the greatest potential to improve. These greater incentives will be reflected in the actual degree of investment made by these parties and the improved competitiveness that results.

9.2. CBA considering new CCGT capacity investment

The core CBA presented in 5.3.1 focuses on DSR as the main LT investment response to cash-out reform. The equivalent capacity of generating plant (CCGT) was also tested in the COM and the results put through the CBA framework. Investment in new generating capacity in general appears to be a less cost-effective response from the perspective of consumers compared to DSR, even after allowing for a significant portion of the cost of the investment to be recovered by returns in the wholesale energy market.

In 2020, this imposes a small net overall cost to consumers (focusing on the LT capacity investment only) to cover the residual costs of the investment, after accounting for any balancing efficiency gains. However, by 2030 under the no-CM scenario there is still a net overall benefit to consumers with new CCGT investment (albeit smaller than under the DSR case) due to the significant reduction in overall unserved energy that the new capacity provides.

Table 25 **CBA summary from domestic consumer perspective – CCGT long term capacity, 2020**

£m/year		2020				
		P1 LT	P2 LT	P3 LT	P4 LT	P5 LT
Producer Surplus	NIC	-107	144	-129	156	145
	RCRC	107	-144	129	-156	-145
	SO balancing and party hedging costs	2	1	3	0	1
	Payments for involuntary disconnections	0	0	0	0	0
	Payments for voluntary disconnections	0	0	0	0	0
	Investment in new capacity	-8	-9	-9	-8	-9
	Investment in reliability	-8	13	-9	13	13
	Price revenue benefit	14	-5	15	-5	-5
Consumer surplus	Price revenue cost	-14	5	-15	5	5
	Reduction in disconnection (new capacity)	0	0	0	0	0
	Reduction in voltage control (new capacity)	0	0	0	0	0
	Reduction in disconnection (interconnector)	0	0	0	0	0
	Reduction in voltage control (interconnector)	0	0	0	0	0
	Payment for involuntary disconnection	0	0	0	0	0
	Payment for voluntary disconnection	0	0	0	0	0
	Value of voluntary disconnection	0	0	0	0	0
Total consumer surplus (+ve = benefit)		-14	5	-15	5	5
Change in average £/MWh (-ve = benefit)		0.05	-0.02	0.05	-0.02	-0.02
Change in average domestic bill £/year (-ve = benefit)		0.15	-0.06	0.16	-0.06	-0.06

Note: totals may not sum due to rounding.

Table 26 CBA summary from domestic consumer perspective – CCGT long term capacity, 2030

£m/year		2030				
		P1 LT	P2 LT	P3 LT	P4 LT	P5 LT
Producer Surplus	NIC	-233	461	-323	451	434
	RCRC	233	-461	323	-451	-434
	SO balancing and party hedging costs	13	2	18	-5	17
	Payments for involuntary disconnections	0	0	0	0	0
	Payments for voluntary disconnections	0	0	0	0	0
	Investment in new capacity	-66	-70	-84	-79	-84
	Investment in reliability	-33	66	-40	73	54
	Price revenue benefit	87	2	106	12	13
Consumer surplus	Price revenue cost	-87	-2	-106	-12	-13
	Reduction in disconnection (new capacity)	7	7	7	7	7
	Reduction in voltage control (new capacity)	60	62	63	61	63
	Reduction in disconnection (interconnector)	1	1	1	1	1
	Reduction in voltage control (interconnector)	31	31	31	31	31
	Payment for involuntary disconnection	0	0	0	0	0
	Payment for voluntary disconnection	0	0	0	0	0
	Value of voluntary disconnection	0	0	0	0	0
Total consumer surplus (+ve = benefit)		13	99	-4	89	89
Change in average £/MWh (-ve = benefit)		-0.04	-0.29	0.01	-0.26	-0.26
Change in average domestic bill £/year (-ve = benefit)		0.83	0.02	1.01	0.11	0.12

Note: totals may not sum due to rounding.

10. APPENDIX D – METHODOLOGY FOR THE CALCULATION OF THE PRELIMINARY RESERVE SCARCITY PRICING FUNCTION

The Reserve Scarcity Pricing Function (RSP) assigns a value to STOR actions as a function of the level of margins in each period (the " STOR replacement price"). If implemented, the RSP would be used to re-price STOR actions when they enter the calculation of cash-out prices, replacing the current buy price adjuster (BPA). Ofgem will develop the details of the definitive form that the RSP function will take in consultation with industry.

For the purposes of quantification of the impacts as part of this model, a preliminary RSP was developed. Historical data was used to determine a relationship between margin on the system, and what LOLP may have been, based on assumptions about likelihood of demand forecast error, and plant failure at gate closure. This simple representation of 'LOLP' was then multiplied by the value of loss load (VoLL) to determine the STOR replacement price.

Expected available capacity for a settlement period was calculated at gate closure, and based on the following assumptions:

- Available capacity in each settlement period is based on the Maximum Export Limit (MEL) of spinning plants, reflecting synchronisation times. For pumped storage, hydro and OCGT plants, the full MEL is assumed available (even if they had zero FPNs in that period).
- As non-BM STOR is not counted in the MEL dataset, 1000MW was assumed to be available and this is added to margins.
- Total available capacity (net of wind) is assumed to comprise a number of equally sized units, with equal but independent probabilities of failure. A probability of cumulative plant losses is also estimated.
- Interconnectors are assumed to flow at outturn values.

The calculation of the LOLP assumes that demand forecast errors are normally distributed, with a mean of zero and a standard deviation of 1.2%. This assumption is based on the historic demand forecast errors observed in 2011 and 2012. Using this distribution, it is possible to calculate different possible levels of expected demand in each settlement period.

All generating units are assumed to have equal and independent chance of failure. Each plant is assumed to have a 3% of failure, and the average plant size is assumed to be 500MW.

Using the estimated margins (based on historic data) and the LOLP calculated for each level of margin, a preliminary RSP was constructed as a linear relationship between margins and LOLP multiplied by VoLL. In the preliminary RSP, the maximum value for the replacement price is set at £6,000/MWh, corresponding with the price for Demand Control actions under the 'with CM' scenario. The function assigns this maximum value when the margin is on or below 500MW. This figure was selected to represent a minimum contingency level, and it is assumed that the SO will instruct voltage control when the reserve margin falls below this threshold. The form of the preliminary RSP used for the model is shown in Figure 1 (Section 1.3).

11. APPENDIX E – LIST OF COMPUTER PACKAGES USED

- Microsoft Excel 2010 – v14.0.6129.5000 (32-bit)
- Microsoft Visual Basic for Applications – v7.0
- Microsoft Excel Solver
- Palisade @Risk 5.0 for Excel
- Microsoft SQL Server Management Studio 2008 R2 – v10.50.1617.0