P305 'Electricity Balancing Significant Code Review Developments'

This Assessment Procedure Consultation was issued on 16 December 2014, with responses invited by 14 January 2015.

Consultation Respondents

Respondent	No. of Parties/Non-Parties Represented	Role(s) Represented
Western Power Distribution	4 / 0	Distributor
ScottishPower	5 / 0	Generator, Supplier, Non Physical Trader, ECVNA, MVRNA, Supplier Agent
IMServ (Europe)	0 / 1	Supplier Agent
TMA Data Management Ltd	0 / 1	Supplier Agent
Drax Power Limited	1 / 0	Generator
GDF SUEZ UK-Turkey	14 / 0	*Not stated*
RWE Supply and Trading GmbH	10 / 0	Generator, Supplier, Interconnector User, ECVNA, MVRNA
SmartestEnergy	1 / 0	Supplier
Flow Energy	1 / 0	Supplier
InterGen UK Ltd.	3 / 0	Generator, ECVNA
National Grid	1 / 0	Transmission Company
DONG Energy	1 / 0	Generator, Supplier
Good Energy	1 / 0	Supplier, ECVNA, MVRNA
Centrica	15 / 0	Generator, Supplier, Interconnector User, Non Physical Trader
RenewableUK	0 / 1	Trade Association
Electricity North West	1 / 0	Distributor
VPI Immingham	1 / 0	Generator
UK Power Reserve Ltd	1 / 0	Generator
Green Frog Power	0 / 1	Generator

Respondent	No. of Parties/Non-Parties Represented	Role(s) Represented
Vattenfall	1 / 0	Generator, Supplier, Interconnector User, Non Physical Trader, ECVNA, MVRNA
Eggborough Power	1 / 0	Generator
Haven Power Limited	1 / 0	Supplier
SSE plc	8 / 1	Generator, Supplier, Distributor, Supplier Agent
First Utility Limited	1 / 0	Supplier
E.ON	7 / 0	Generator, Supplier, Interconnector User, Non Physical Trader
Stark Software International Ltd	0 / 1	Supplier Agent
Utilita	1 / 0	Supplier
Cornwall Energy	0 / 1	Consultant
EDF Energy	9 / 0	Generator, Supplier, Non Physical Trader
Co-Operative Energy	1 / 0	Supplier

A response from **Energy UK** can be found in Appendix 1

Questions Asked

Question 1: Do you believe that P305 would better facilitate the Applicable BSC Objectives and should be approved?

Summary

Yes	No	Neutral/No Comment	Other
11	16	2	1

Responses

Respondent	Response	Rationale
Western Power Distribution	Neutral	We do not hold a strong view as to the merits of this proposal. Our comments on this modification proposal are therefore limited to the impacts it will have on our operations and systems.
ScottishPower	Yes	P305 will better facilitate Applicable Objective (b) by reflecting to generators and demand side response providers through cash-out prices the value attached to security of supply by consumers and hence the value of providing flexible and reliable response. By providing some of the "missing money" more marginal cash-out prices may incentivise investment in new generation capacity thus better facilitating the operation of the National Electricity System. P305 will better facilitate Applicable Objective (c) through enabling those Parties able to provide flexibility and balancing services to earn a reward which better reflects the value of those services thus better facilitating competition for provision of those services and encouraging entry into this market. Removal of dual imbalance prices will remove the existing imbalance price spread and encourage Parties to balance their positions more efficiently. It should reduce net imbalance costs for many Parties, particularly smaller ones.
IMServ (Europe)	Yes	We believe this better support objectives C and D although this is tempered somewhat by the risk being introduced by so many changes in this area in such a short time frame.
TMA Data Management Ltd	No	P305 would better facilitate BSC objective b and c however, we would prefer to have P305 progressed in the form of several Modifications. Please see our response to question 16 for more details.

Respondent	Response	Rationale
Drax Power Limited	No	The relevant applicable objectives are (b), (c) and (d) in our opinion. Our view is that the current imbalance arrangements perform well when measured against the applicable BSC objectives. Therefore, significant changes would be required to represent an improvement on the Baseline. P305 represents such a significant change to the existing arrangements. At this time we do not consider that it has been demonstrated that P305 represents an improvement against the Baseline arrangements. Specifically, a change to PAR1MWh carries significant risk of system pollution of cash-out prices. We believe a more cautious approach (as outlined in answer to question 7) will represent an improvement on the Baseline. We also have concerns that a single cash-out price may be detrimental to wholesale market liquidity, particularly in extreme tight periods. Further evaluation of the impact of a single price is required to confirm whether a move to a single price better facilitates the applicable BSC Objectives. While there is some merit in principle in determining a price for involuntary demand disconnections, the administered price proposed represents a significant risk to independent market participants. Further analysis to confirm the distributional impacts associated with this change will be most welcome. Further development on the RSP Function and LoLP Method is required to ensure these can deliver consistent and transparent scarcity signals to market participants. Testing the methods in real market conditions is a fundamental pre-requisite to ensure that such an approach can perform within the existing market arrangements. Until such testing is completed we do not consider it appropriate to implement an RSP Function, certainly as currently developed. Overall, without further development, testing and evaluation of the impacts of P305, we cannot conclude that this, as a package, better facilitates the relevant BSC Objectives.
GDF SUEZ UK-Turkey	No	GDF SUEZ supports two aspects of the P305 – a single and a phased approach to a more marginal cashout price. In combination, these will provide incentives for BSC Parties to balance and therefore for the market to balance.

Respondent	Response	Rationale
		GDF SUEZ agrees that that demand disconnection volumes should be included in the cashout calculation. However the definition of demand disconnection extends to voltage reduction. GDF SUEZ does not agree that the volume of voltage reduction instructed should be included in the volume calculation as the SO will instruct more voltage reduction than it expects to be delivered resulting in a system that is overly 'short'. Further detail is provided in the response to Q2. GDF SUEZ does not therefore support this aspect of the modification. With a £3000/MWh VOLL, the RSP part of the modification would have had no impact on cashout prices in 2013 and it is highly questionable whether it would in the future. If however, LOLP did rise high enough for the RSP function to apply, then because of the NIV tagging process, there would still be an enormous degree of uncertainty as to whether the replacement price would factor in the cashout price. The only way the market will properly react to signals of system scarcity is if the cashout rules are clear and information relevant to the calculation of cashout prices is readily available. Shift traders and dispatchers need to make decisions in very short timescales and so clarity is absolutely vital. They need cashout prices that give a reliable scarcity signal. GDF SUEZ believes that P305 will just provide misleading signals creating confusion and uncertainty. GDF SUEZ therefore sees no benefit in implementing this part of the change. Further detail is provided below. Since the RSP function and the incorporation of instructed voltage reduction form part of the overall modification package, GDF SUEZ does not support the implementation of P305. **Comments on the RSP function** Before looking at ELEXON's analysis of the impact of the RSP function, intuitively it will affect cashout very rarely. This is because all of the following would have to be true: • The system would have to be short; and • The LOLP value forecast at 24 hours out and moving toward gate closure would have to

Respondent	Response	Rationale
		provide a consistent signal that there was going to be a problem. The Graph on page 11 of the Detailed Impact Assessment suggests that based on the period considered this is not the case; and • LOLP would be high enough to change the STOR utilisation fee; and • After NIV tagging the RSP action would have to remain in the stack. ELEXON's historic analysis for P305 analysis illustrates well the failure to meet all of the first three from the above list of conditions. With a £3000/MWh VOLL, using the LOLP data determined one hour ahead, the LOLP value would have been high enough to change the utilisation price of accepted STOR actions for one settlement period in 2013 - 8th July SP 32. ELEXON states on page 21 of its' historic analysis that all 36 of the actions that were re-priced in this period (out of 38,225 STOR actions in the year) would have been tagged out. Where cashout prices have increased under the P305 analysis, they are as a result of the inclusion of non BM STOR volumes which have switched the system from being long to short coupled with lower PAR value[1]. Therefore, none of the largest increases in cashout prices using 2013 data and a £3000/MWh VOLL result from the RSP function. With a £6000/MWh VOLL, ELEXON has confirmed since the consultation was published there would have been 4 settlement periods in 2013 where the LOLP value was high enough to lead to the STOR utilisation price being re-priced. Of the 46 actions that were re-priced, 36 of these were the same actions as where VOLL = £3000, and of the extra 10 actions: three were on 01 Feb 2013 during SP 37, four on 07 Feb 2013 during SP 36 and three on 08 Jul 2013 during SP 31. ELEXON notes that "our analysis did not calculate prices where VoLL equalled £6,000/MWh". It is not therefore clear how many of these 10 actions would have fed into the final cashout price with a £6000/MWh VOLL. Under the existing rules of cashout and in particular

[1] ELEXON notes in its historic analysis on P305 that 'the impacts of RSP observed in our analysis are likely to be a consequence of additional non-BM STOR actions and revised Buy Price Adjusters in the Main Price calculation, rather than high values of Loss of Load Probability (LoLP) and RSP influencing the price calculation'

Respondent	Response	Rationale
		the NIV tagging, the price behaves unexpectedly at present. For example: on a tight day, if oil/peaking plant is called on in BM, one might expect the SBP to be high if the system is short, but it turns out not to be because lots of bids are taken as well for system reasons or reserve creation and the most expensive offer therefore disappears in the NIV tagging. As the PAR value reduces, it will becomes much more challenging to know whether the replacement price will remain untagged to affect cashout. Under a PAR 1MWh, whilst from ELEXON's analysis it would seem highly unlikely that the price of STOR actions will be changed, if the RSP part of the modification does result in a higher utilisation price, it will be a lottery as to whether the replacement price and also demand disconnection will end up feeding into the cashout prices. 2013 could be considered to be 'benign' from a system security perspective and one might consider it worthwhile repeating the analysis using all the STOR data for 2014 to see if the RSP function would have led to a uplift in the utilisation price and then a change to the cashout price. The list of conditions that would have to be concurrently true for the RSP function to affect the cashout price will however always apply. Cashout price should provide a signal that market participants can react to. The RSP part of P305 does not provide this. P305 will just provide misleading signals creating confusion and uncertainty. In the context of creating signals of scarcity and also to balance, confusion and uncertainty are not helpful. Ofgem should therefore question whether there is any point in having Reserve Scarcity Pricing and instead should retain the BPA adder (but include non BM STOR into cashout). GDF SUEZ therefore believes that P305 fails to better facilitate the following BSC objectives b) The efficient, economic and co-ordinated operation of the National Transmission System The RSP aspect of P305 will provide misleading signals to the market. This is neither economic or efficient. c) Promoting effective competition in the generation

Respondent	Response	Rationale
		and supply of electricity, and (so far as consistent therewith) promoting such competition in the sale and purchase of electricity – The cashout arrangements are already highly complicated and P305 in its entirety adds to this complexity making it near impossible to have a view on the outturn cashout price. This does not promote competition and is likely to discourage new entrants. d) Promoting efficiency in the implementation and administration of the balancing and settlement arrangements Had the RSP function been in place, there would have been no increase in the cashout price for 2013. Where the cashout prices has increased it has been because non BM STOR is included in the calculation. The RSP aspect of the modification therefore increases complexity for no benefit. It is not efficient to introduce a change that has no benefit.
RWE Supply and Trading GmbH	Yes	P305 will better meet Objective b) and Objective c). *Objective b) The efficient, economic and co-ordinated operation of the National Electricity Transmission System* The proposed changes to the cash-out price calculation make prices more reflective of the value to consumers of balancing, particularly during times of very tight margins. In doing so, market participants will be incentivised to make more efficient balancing and investment decisions. This should result in reductions in the total costs (to the SO and market) of maintaining a balanced system, whilst presenting savings on the costs of delivering secure electricity supplies in the future. Making cash-out prices sharper signals the commencement of reforms designed to better reflect the value of flexible plant in the balancing arrangements. It may therefore contribute to deferring the mothballing of flexible plant and help counteract potential tightening of margins. *(c) Promoting effective competition in the generation and supply of electricity and (so far as consistent therewith) promoting such competition in the sale and purchase of electricity* Reflecting the value that actions deliver supports

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		effective competition by aligning competitive incentives of market participants with the interests of the consumer. A single marginal cash out price that appropriately includes the value of reserve and demand control (at VOLL) eliminates distortions in the arrangements that currently impede value reflectivity, thereby supporting effective competition that drives value for the consumer. Strengthening the energy imbalance price signal should incentivise market participants to trade to balance their positions ahead of Gate Closure. This will result in increased liquidity in the forward market and benefit competition by encouraging investment in flexible capacity (flexible generation, demand participation and other technologies). The inclusion of a single imbalance price removes the existing inefficient price spread and for many market participants, in particular smaller parties who are less likely to drive the system length. This should reduce net imbalance costs and therefore help to mitigate the potential imbalance risk faced by market participants. P305 may alter the incentives for parties to enter the market. The reforms address existing inefficiencies which limit the potential for some parties, in particular those offering services that facilitate flexibility and balance (such as DSR or storage), to participate in the wholesale electricity market.
SmartestEnergy	Yes	However, we are of this opinion because it is the single cash out aspect which is most needed. In terms of PAR values we believe an alternative would be even better than the proposed.
Flow Energy	Yes	A single cash out price will better facilitate the efficiency of the balancing system, it will also help protect competition in mitigating the risks to the small independent (and especially domestic) suppliers which are introduced by the reduction in PAR volume
InterGen UK Ltd.	Yes	Yes. InterGen was fully supportive of the EBSCR proposals and has urged the Regulator to progress and implement the conclusions swiftly, to the benefit of industry, consumers and investors.
National Grid	Yes	For the reasons set out in the Proposal, we believe that P305 better facilitates Applicable Objectives (b)

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		and (c). Reductions in the PAR volume, reserve scarcity pricing and pricing demand control actions into cash-out ensure that the imbalance price signal can appropriately capture the value that flexible capacity provides during periods of tightening margins. Meanwhile the move to a single imbalance price rewards those market participants whose imbalance positions help to reduce the overall imbalance on the Transmission System. Applicable Objective (b) is thereby better facilitated by making the cash-out price signal more reflective of the value of a given imbalance position to the Transmission System and ultimately the consumer. Competition is promoted under Applicable Objective (c) by removing the inefficient price spread of the dual price system and reducing net imbalance costs. Parties may also be encouraged to enter the market to provide flexible capacity with a sharper price signal that better reflects the value of those services.
DONG Energy	No	DONG Energy is committed to the development of an overall more efficient design of the electricity market, including the Balancing Mechanism. We therefore welcome the opportunity to comment on the changes to the BSC proposed in P305. However, DONG Energy does not believe that P305 in its current form will better facilitate the applicable BSC Objectives for the reasons outlined below. Overall, we are not convinced that higher cash-out prices necessarily drive efficiency in the BM mechanism and system and that, as a consequence, there will be subsequent material change towards investment in more flexible and fast response plant. We believe that other regulatory reforms such as the Capacity Market may similarly, or better, support the provision of necessary reserve requirements in the short term market and/ or periods of system stress. Furthermore, DONG Energy believes that there are other potential solutions and areas which justify further investigation. For example, the development of a deeper and more liquid intraday market could help better accommodate and integrate variable generation and smaller market participants. Find below DONG Energy's position with regards to

Respondent	Response	Rationale
		the different proposed changes. **Reductions in PAR value** It is intended that the reduction in PAR from 500 to 50 and subsequently to PAR1 will send sharper price signals to market participants and therefore provide stronger incentives for balancing generation and demand portfolios ahead of gate closure. Ofgem suggests that a lower PAR level will result in more marginal prices and therefore cost reflective balancing actions. However, DONG Energy believes that the current, higher PAR arrangements sufficiently incentivise BSC parties to balance their positions. We do not believe that a radically sharper, or even fully marginal, cash-out price will improve overall forecasting accuracy for certain groups of market participants, particularly those who cannot precisely predict demand and/or have a variable fuel cost. These parties are then fully exposed to the higher cost whilst not being able to mitigate the increased risk. It is our view that system prices which are based on a higher PAR value are a closer reflection of the overall actual cost that is caused by the balancing of the market. Equally, in a lower PAR scenario the amount of money recovered from the market would be expected to be significantly higher than the actual cost. We are concerned that this money could then be asymmetrically redistributed through RCRC and overall lead to a higher inefficiency of the Balancing Mechanism. Furthermore, DONG Energy would expect that as a result of high imbalance prices parties with similar trading characteristics will try to adopt extreme, inverse positions to the market which could create a risk of increased imbalances. Historic analysis completed by Elexon showed that, particularly in a PAR1 scenario, the number of times imbalance prices turn negative significantly increase which suggests that this is likely happen more often in the future. DONG Energy is also concerned that the expectation of system stress could incentivise generators to hold capacity back from the wider market to protect themselves from high imbalance prices which would lead to decreased liquidity in the market. This can

Respondent	Response	Rationale
		have significant impact on the accuracy of price signals that will be sent from the market in these situations and would likely lead to higher imbalance volumes than with a less marginal price calculation. In summary, DONG Energy is concerned that a significantly lower PAR value could lead to increased market disruptions and inefficiencies. In addition, the likelihood increases if proposed implementation takes place without sufficient time for market participants to adapt. Notwithstanding the above comments, with respect to the current proposal, we believe that additional impact analysis should be undertaken focussing on further forward modelling: • different timelines and PAR (to include PAR450, PAR350, PAR250); • taking account of extreme balancing positions; • sensitivity analysis of different behavioural profiles and the impact on the consumer; • on increased occurrence of negative imbalance prices, and • based on a changed generation portfolio due to the latest capacity market results (compared to the original modelling). DONG Energy does not believe that the proposed pathways under P305 will positively impact BSC objectives B and C. **Moving to a single imbalance price** The Dual Price calculation currently in use creates an asymmetry between parties causing imbalances and the ones that having a counter effect on the system. DONG Energy believes that through more efficient imbalance pricing and removing disadvantages from particularly smaller market participants the introduction of a Single Imbalance price better facilitates the BSC objectives B and C. **The introduction of Reserve Scarcity Pricing** The introduction of Short Term Operating Reserve (STOR) into cash out pricing via the Reserve Scarcity Price (RSP) seeks to better reflect the cost

Respondent	Response	Rationale
		for flexible generation. It is proposed that the RSP shall be calculated as a product of a Loss of Load Probability (LoLP) representing the probability of demand control actions and the Value of Lost Load (VoLL) which will be set initially to £3000/MWh and subsequently increased to £6000/MWh. The LoLP provides an indication of the probability that generating supply is lower than required capacity and will be published at various intervals ahead of Gate Closure with the value at Gate Closure going into the RSP calculation. In times of high system stress, which are likely to occur more often over the next years as capacity margins are tightening, and particularly after the increase of VoLL to £6000/MWh, we expect the RSP to more frequently set the main imbalance price in a PAR1 scenario or increase prices in higher PAR scenarios. DONG Energy sees the introduction of an RSP into cash out as being more cost reflective than under the current regime and that there is some overall market advantage of being able to better identify and assess times of system stress through an LoLP function estimate ahead of Gate Closure. However, there is also the potential for the RSP to significantly increase system prices in periods of extensive system stress. DONG Energy believes that if the RSP is introduced then the final LoLP for the price setting should be determined minimum one hour ahead of gate closure to minimise the risk of unexpected price spikes. However, we believe that there should be assessment of static LoLPs under varying scenarios. Additionally, forward modelling of RSP scenarios with static and dynamic LoLPs showing their direct impact on imbalance prices. **The introduction of pricing for Demand Control actions** System Operator Demand Control Actions are not covered by the current imbalance pricing methodology. The proposed solution in P305 seeks to price instructed demand reduction at VoLL (£3000/MWh; £6000/MWh in 2018/19) to incentivise the market to avoid the need for Demand Control Actions. Elexon's historic sample analysis (2010-2014) does

Respondent	Response	Rationale
		not include any involuntary demand disconnection, indicating that these events happen rarely and are therefore unpredictable. As a result we do not see it as proven that the market could avoid these events from materialising. Even though DONG Energy sees that Demand Control Actions should be cost reflective we believe that these actions should be flagged as system balancing action and only included in cash-out if they are less expensive than the most expensive energy balancing action. Therefore we believe that including Demand Control into cash out will not better facilitate the applicable BSC objectives.
Good Energy	No	The historic analysis undertaken by Elexon shows that the introduction of single cash out prices reduces imbalance cash flows for all party types, and the smaller parties in particular, thereby better facilitating Objective (c), but that this benefit is consistently eroded as PAR is reduced. However, the historic analysis has been undertaken during a period of relatively benign market conditions and P305 will doubtless lead to behavioural change. We would expect larger trading parties who are better able to afford sophisticated forecasting systems and other associated resource & experience to be better able to adjust to a market with sharper cash out prices from lower PAR and Reserve Scarcity Pricing (RSP). We are particularly concerned by the potential impact of extreme events on smaller parties: particularly renewable suppliers and independent (non-portfolio) generators where, if the wind does not blow or a generator trips at times of system stress, their imbalance is penalised by very severe cash out prices due to the effect of low PAR and high LoLP in conjunction with VoLL. This is essentially an unmanageable risk which will add to their overall costs and could potentially put them out of business. In view of the above we consider that, taken overall, P305 does not better facilitate Objective (c). Whilst single cash out prices promote more efficient balancing by parties by reducing the incentive for positions to be long, and a lower PAR value and the introduction of RSP will better reward flexibility, we have concerns at possible distortions to cash out prices due to erroneous flagging and tagging of balancing actions. We note that although the

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		Transmission Company retrospectively checks all tagged actions to ensure that they were correctly tagged, it doesn't check the actions it did not tag to see whether they should in fact have been tagged. This creates the potential for an action that should have been tagged out to go on to set the imbalance price. We are concerned that the use of marginal values could amplify existing inefficiencies in the current calculation. We note that the Transmission Company can sometimes accept a high-priced offer in one settlement period to resolve an issue at that time, but because of the dynamics of the BM Unit called upon, that offer may have to persist for several hours, impacting future settlement periods where a lower-priced offer would otherwise have been accepted. Our concerns are exemplified in the Elexon Historic Analysis by the lowest price calculated over the period of the analysis of -£250/MWh, assuming PAR 1, Single Price but excluding RS requirements. On querying this recently we learnt it was the result of a bid that should have been flagged and tagged out but wasn't. We are also of the view that the proposed 'dynamic' LoLP function appears unpredictable, is not sufficiently transparent and is more a measure of short term plant availability than lack of capacity. In view of these concerns we consider that, taken overall, P305 does not better facilitate Objectives (b), (c) or (d) and is neutral to the other BSC Objectives.
Centrica	No	We believe that the implementation of PAR50 from November and PAR1 in 2018 will result in highly unpredictable cash-out prices that parties may be unable to react to. Experience from other countries indicates that this could result in parties not being incentivised to balance and leaving an open position at gate closure – contradicting applicable objective b, the efficient, economic and co-ordinated operation of the National Electricity Transmission System. Furthermore, some players, who are inherently more likely to be out of balance may be adversely impacted by such a lower PAR being implemented - contradicting applicable objective c, promoting effective competition.

Respondent	Response	Rationale
RenewableUK	-	At this time RenewableUK does not believe it is possible to judge if P305 would better facilitate the Applicable BSC Objectives. This is primarily because the analysis required to assess the impacts of making cash-out more marginal on different market participants has not yet been carried out. Given the limited ability of variable renewable generators to respond to sharper balancing signals, they will be impacted more heavily than other types of generator, an effect that has not been investigated in sufficient depth. We would encourage Elexon and the working group to bring forward analysis of a wide range of options so that stakeholders can take informed views on these important proposals.
Electricity North West	No	We do not believe that the solution is sufficiently developed to determine whether the objectives are better facilitated.
VPI Immingham	Yes	Yes, P305 would better facilitate the applicable BSC objectives compared to the current arrangements. The proposed changes would be more cost reflective as it would sharpen the price signals associated with balancing the system and hence incentivise participants to balance their position ahead of gate closure. This would incentivise market participants to trade, improving liquidity and hence improving competition. It would also better reflect the value of flexible plant, particularly in times of system scarcity hence enhancing competition. All of these combined factors better deliver objectives (b) and (c) of the BSC objectives and therefore we think the modification should be implemented.
UK Power Reserve Ltd	Yes	UK Power Reserve believes that P305 will primarily better facilitate objectives (B) and (C) and of the BSC objectives. The principle benefit of P305 will be to increase the pricing signals to flexible capacity to address the missing money required to incentivise a more robust, secure and reliable energy market. P305 will encourage and reward smarter more innovative market participation and ultimately benefit the end consumer at an overall lower cost. Objective (B) will be better served through the sharpening of pricing signals to the market which will enable improvement in the provision of economic flexible capacity. Objective (C) will be better served by rewarding

Respondent	Response	Rationale
		parties that have more balanced positions whilst more accurately representing the cost implications of imbalance, this is of particular importance with declining margins on capacity.
Green Frog Power	Yes	A key element of an efficient competitive market is liquidity and confidence that prices reflect the value. Under current arrangements, peak prices are muddied by the inclusion of non-relevant activities, and the true, marginal cost of meeting peak demand is not realised by generators, suppliers, or final customers. Effectively, the signal of the value of peak power is muted, which in turn means that the penalty for not buying sufficient power to meet that peak demand is insufficient. The proposal P316 brings in the reforms to PAR volumes and single pricing at a more sensible rate than P305, because the objectives will be met sooner. Reserve Scarcity Pricing and the LOPL function should also be brought in as soon as possible if the overall objectives of reform are to be fully met.
Vattenfall	No	Vattenfall welcomes the opportunity to comment on P305. Vattenfall supports a system with 1) Marginal Pricing 2) Single imbalance price/single cash out price Vattenfall is mindful of the need to implement the conclusions of the Significant Code Review report in a meaningful way. However we have some concerns about the manner in which this mod proposes proceed. Firstly, Vattenfall supports the move to a single imbalance price. It supports Applicable BSC Objectives A and B. Furthermore, Vattenfall believes that it is necessary if moving to marginal balancing pricing. On the issue of marginal pricing, although a move to a lower PAR value could be perceived to support Applicable BSC Objective (D), Vattenfall believes that this consideration should be balanced with the increased impact on intermittent plant, particularly for smaller market players. Moving to the lowest PAR in addition to a single cash out price benefits large scale integrated utilities who are able to balance their own portfolio more readily than other market players. This move is against other action

Respondent	Response	Rationale
		being taken by the regulator/CMA to increase competition in the energy sector. It is against the BSC applicable objective (C). The analysis undertaken by Ofgem has suggested that parties with more accurate forecasting would benefit from these reforms. As a company with intermittent generation only in the UK, the accuracy of the forecasting is obviously limited by the technology available at the time. Waiting to reduce the PAR values further will enable greater forecasting accuracy as new methods are developed which improve the accuracy of weather forecasting. In addition, the forward modelling undertaken by Ofgem assumed that all parties would and could change behaviour in a rational way. It is not necessarily the case that all parties have the capability to immediately change behaviour. This supports the argument for a slower transition through the reduction in PAR value to enable adjustments to processes requisite technology to change, to facilitate changes in behaviours in line with market incentives. In conclusion then, P305 negatively impacts smaller players and intermittent plant. A slower transition to a lower PAR value is needed. Vattenfall also believes that PAR 1 could be too low a PAR to transition to. A higher PAR value might achieve the same ends. As in our consultation response to EBSCR, we would support the insertion of impact assessments before all reductions in PAR, to assess how the market has responded, how groups of players have been impacted and whether further reductions are needed.
Eggborough Power	No	Ofgem's SCR conclusions focussed largely on the need for more marginal cash-out prices. The other elements of the conclusions are enhancing more marginal prices, but only at certain times. A move to more marginal pricing under P316 would therefore be a step forward in achieving Ofgem's goals while the other elements of P305 continue to be developed. We therefore believe P316 would better meet the relevant objectives. P305 does not better achieve the relevant objectives as it does not give such clear, efficient pricing signals and seems likely to damage competition between market participants. This is largely because the use of the LOLP function seems to create

Respondent	Response	Rationale
		signals that the market cannot see nor reasonably respond to. We appreciate that Ofgem desires a package of change, but this does not seem like the best modification as it stands and could benefit from further developments. P305 would risk sending suppliers longer as they try to manage the risks associated with an infrequent but significant risk of extreme prices. This may have adverse effects on the level of competition. It would also make the operation of the system less efficient if more balancing is required by NG to counter increasing system length.
Haven Power Limited	No	We believe the relevant applicable objectives are (b) The efficient, economic and co-ordinated operation of the National Electricity Transmission System (c) Promoting effective competition in the generation and supply of electricity and (so far as consistent therewith) promoting such competition in the sale and purchase of electricity (d) Promoting efficiency in the implementation of the balancing and settlement arrangements To improve objective (b) P305 should increase the incentive on parties to balance their position. Reducing the PAR value increases the incentive for parties to balance as it increases the financial cost of being out of balance. Reducing the PAR value leads to an increase of RCRC payments to parties. Overall parties that are better balanced than average will gain while those who are worse than average will lose out. This should encourage parties to put more resources into balancing their accounts. However, we do not believe that single pricing will improve objective (b). The introduction of single pricing diminishes the incentive for parties to balance their positions. If a party has length in the direction of the system they lose but they will also gain if they are opposite to the system. Under current conditions a single price regime is likely to encourage parties to go long. This volatility could potentially make it much harder for National Grid to balance the system. As an example to illustrate our arguments we consider our own party, Haven Power. We have put considerable effort over the last few years into

Respondent	Response	Rationale
		improving our demand forecasting. We now have one of the lowest imbalance errors in the industry, very similar to that of the 2nd best of the six largest suppliers. Reducing the PAR value would benefit us, as while our imbalance costs would go up we would receive more back though RCRC to compensate for this. However, a move to single cashout would not be in our favour as money that was previously fed back via RCRC will now go to parties that were out of balance, in the opposite direction to the system. To minimise our costs it would be in Haven's interest to take considerable length to gate closure, however, if everyone does this then the advantages of doing this diminish. A move to a fundamentally different imbalance pricing mechanism will undoubtedly result in a period of time of high volatility as all parties are trying to find a new balancing strategy that minimises their losses. In addition we do not feel that the introduction of single pricing improves objective (c). Single pricing encourages parties to balance outside of the system, for example through CfD contracts. This could have the effect of decreasing the liquidity of the near term market. In particular during periods when LoLP is high the market may completely dry up as no parties are willing to sell power in the hope that they may be able to obtain up to £3000/MWh (£6000/MWh from 2018) from the balancing mechanism. We recognise that it is very difficult to change the imbalance pricing mechanism to simultaneously increase the incentive on parties to balance while not putting smaller independent parties at a disadvantage. This is because it is generally the small parties, and particularly newcomers to the industry, that find trading to balance the most difficult. The largest difficulty facing these parties is obtaining sufficient credit to enable them to trade accurately to their forecasted position. We feel that measures need to be put in place to solve this problem before increasing the costs associated with being out of balance. **An alternative suggestion is that the majority of parties are subject to dual prices, but very small parties are exposed to a single price.** If the decision is made to proceed to single pricing we strongly believe that it should be introduced at a time of year when the system is typically relatively

Respondent	Response	Rationale
		benign. This is because there is likely to be a period of volatility and unpredictability while parties change their strategies in attempt to benefit as much as possible from the new system. We would suggest beginning in April or May 2016. An additional advantage of waiting until then is that PC5-8s will be settled by HH, which should help many parties forecast their demand more accurately. While there is some merit in principle in determining a price for involuntary demand disconnections, the administered price proposed represents a significant risk to independent market participants. Further analysis to confirm the distributional impacts associated with this change will be most welcome. We do not think that the proposed approach for pricing RSP better facilitates objectives (b), (c) or (d). While we agree that RSP pricing is not ideal, the new methodology does not appear to sharpen prices in a predictable manner. In many instances the new methodology reduces system prices. We are concerned that the proposed method for pricing reserve will not deliver consistent and transparent scarcity signals to market participants. Testing the methods in real market conditions is a fundamental pre-requisite to ensure that such an approach can perform within the existing market arrangements. Until such testing is completed we do not consider it appropriate to implement an RSP Function, certainly as currently developed. Our view is that the current imbalance arrangements perform well when measured against the applicable BSC objectives. Therefore, significant changes would be required to represent an improvement on the Baseline. P305 represents such a significant change to the existing arrangements. At this time we do not consider that it has been demonstrated that P305 represents an improvement against the Baseline arrangements. Overall, without further development, testing and evaluation of the impacts of P305, we cannot conclude that this, as a package, better facilitates the relevant BSC Objectives.
SSE plc	Yes	On balance SSE believe that the proposed modification better facilitates both objective b) and objective c) for the reasons stated by the proposer. Whilst we see mostly positive, but some negative aspects to the proposed solution, on balance the

Respondent	Response	Rationale
		positive effects outweigh the negatives. SSE believe that the value of flexibility and risk is not sufficiently priced into the energy market currently, dampening price signals and undermining the credibility of cash-out as an incentive price. Traders are able currently to carry large short positions into the within-day market with no reserve because the threat of cash-out rising to penal levels is not credible. This is increasing the overall cost of balancing. This has resulted in a lack of investment in all generation and particularly flexible capacity as well as the imposition of higher balancing costs on the System Operator, at a time when such capacity is needed to cope with the system management complexities and costs created by reductions in existing flexible capacity due to environmental regulation as well as an increased penetration of intermittent generation. Whilst recognising that short-term impacts may see wholesale prices rise in response to increasing risk, SSE are persuaded by the analysis presented by Ofgem in their EBSCR that the behavioural response likely to be seen as a result of the proposed changes represent a more efficient outcome in the long-term than maintaining the status quo, as variability of generation supplied to the system increases with increasing levels of intermittent generation. Marginal pricing will provide a more efficient balancing and flexibility signal, and strengthen the relationship with forward markets (often disconnected currently). Forward trading behaviours will adapt to mitigate imbalance exposure and encourage innovation and investment in the development of flexible products and technologies, thus promoting competition in the market. Equally the market should be better incentivised to contract forward and leave less residual imbalance for the SO to resolve; thus increasing the overall efficiency of balancing and security of the system. Single pricing will remove the costs of the system price spread that single asset or non-scale players in particular are currently exposed to, to a greater extent than portfolio players; and will therefore offer relief for those players against the potential effects of an increasingly marginal price, better

Respondent	Response	Rationale
		facilitating competition as unnecessary costs are minimised. Reserve option fees are currently priced into cash-out based on historic usage patterns which does not relate to future usage patterns, and does not properly reflect the value of the reserve procurement to periods of scarcity on the system. Reserve Scarcity Pricing provides a better means of attributing that scarcity value to settlement periods when the system needs the reserve the most (albeit SSE would prefer to see a static LoLP calculation when deriving an RSP), incentivising an appropriate forward response to rising LoLP signals and increasing the overall efficiency of balancing and securing the system. It is appropriate for Suppliers in particular, to have the correct incentives to ensure that they cannot realise excessive windfalls through cash-out by halting forward trading activity and potentially precipitating demand control actions. However, SSE are concerned that calculating an artificial supply volume that pre-supposes consumer demand behaviour, and subsequently adjusts Suppliers' imbalance positions; could inadvertently leave Suppliers short and exposed to VoLL price that have responded in a rational and correct way. In turn we are concerned that the process opens itself to legal challenge.
First Utility Limited	No (Potential Alternative: Yes)	Regarding the proposed modification: (b) The efficient, economic and co-ordinated operation of the National Transmission System - Yes We agree with the theoretical principle of sharpening the price signal through a reduction in PAR, the change to single cashout and the resulting theoretical benefits that might come about. However, if the signal is sharpened without ensuring the pre-gate-closure traded markets have sufficient liquidity to enable all participant types to transact in order to avoid the extra risk created by this sharper signal, this will act as a barrier to competition. For this reason we believe the sharpening of the signal should be more gradual, only being layered in as the effects of the previous step down in PAR have been proven not to introduce adverse unintended consequences. (c) Promoting effective competition in the generation and supply of electricity, and (so far as

Respondent	Response	Rationale
		consistent therewith) promoting such competition in the sale and purchase of electricity - No Whilst this is a theoretically good solution in a perfect and liquid market, the market is imperfect and has poor liquidity so that those imperfections are likely to undermine the value of the theoretical solution. The theory suggests that new products will become available to allow independent suppliers to mitigate the increased risk resulting from the modification. However, there are adverse distributional impacts that might create perverse incentives for vertically integrated suppliers to: • Withhold risk mitigating wholesale electricity products (to ensure they have reserve to optimise their own balancing performance) • Withhold risk mitigating wholesale electricity products (to ensure others cannot balance as accurately so that they continue to receive abnormally high RCRC receipts) We believe the historic data that has been used to analyse this modification is flawed as it looks at the impact on participants in historical time periods where the system has not been stressed (ie not at times with low capacity margins). The analysis also assumes that bidding behaviour in a more marginal cashout environment would remain as it was prior to the sharpening of cashout. We believe bidding behaviour will change in a way that increases risk more than assumed in the analysis (which potential should in any event be provided for in that analysis), and this requires more understanding against BSC objectives before the more extreme marginal cashout changes can be properly considered. We also believe that credit requirements will increase for First Utility and indeed all independent suppliers which will require funds to be reallocated within those businesses resulting in reduced ability to compete for new customers. We believe there could be unintended consequences that might drive behavioural incentives that may not work to promote effective competition. We therefore suggest caution with respect to the rate of PAR reduction. (d) Promoting efficiency in the implementation and administration of the balancing and settlement

Respondent	Response	Rationale
		arrangements - No The new arrangements are significantly more complicated for Elexon to administer than the current baseline especially in the areas of Reserve Scarcity Pricing, LOLP, etc. Changes such as this do not only affect Elexon: all BSC parties will need to modify their revenue assurance models so that any errors can be detected quickly and reported. On balance - regarding the proposed we believe the dis-benefits outweigh the benefits. If our alternative suggestions were adopted then our position regarding BSC objective c would change to "yes" - better facilitation of the BSC objectives.
E.ON	No	Overall we believe that the measures combined in P305 would not better facilitate the BSC Objectives. Moving to a single price, simplifying arrangements and removing the spread risk created by the current BSC dual pricing/dual account set-up, should in theory be an improvement under Objective (d), although we understand that dual pricing was set up to help incentivise parties to balance, supporting Objective (c). It also seems that in combination with the other P305 changes, single pricing could lead to an unfair situation with some well-balanced parties seeing negative rcrc impacts far greater than their imbalance costs owing to the actions of less well-balanced parties. Other elements of the package currently proposed would also have negative impacts most seriously under Objective (c), but also (d) and potentially (b). P305 is neutral with respect to Objective (a) and also (f); the changes put forward are not necessary to assist administration of Contracts for Difference or other aspects of the CM pursuant to EMR. Until European Network Codes are finalised it is unclear whether making changes to current GB balancing arrangements might pre-empt any that might be necessary to comply with EU requirements. Thus P305 would provide no definite benefit under Objective (e). It would, however, raise the risk that corrections might be required to amend GB arrangements in a few years leaving GB parties facing further upheaval; such instability is not helpful for existing or attracting new market participants. Concerning Objectives (b) and (d), the Proposer

Respondent	Response	Rationale
		claims that P305 will strengthen the incentives on parties to make 'efficient balancing decisions, particularly during times of tight margin'. We are not aware of any evidence transpiring through the EBSCR that parties make inefficient decisions, only that the dual price risk provides an incentive to err towards a long position. However while implementing single pricing would remove the SBP-SSP spread, by reducing PAR dramatically in P305 the correspondingly sharper imbalance price would only exacerbate the incentive to go long. This would be less efficient and risks the TSO having to take more balancing actions than at present. In order to make more efficient balancing decisions parties would also need more accurate information, but we understand that large Suppliers can typically forecast their demand with an accuracy of ~1.7-2.0% MAPE (Mean Absolute Percentage Error). It is unlikely that this can be much improved, while the cost of such investment can also be prohibitive (for no guaranteed return). The other potential benefit claimed under (b) is that P305 might support security of supply through encouraging certain investment decisions, innovation, and possibly deferring the mothballing of flexible plant. E.ON does not share this view. It is in parties' best interests to have plant available to the market at all times therefore will have no effect on maintenance schedules, which have many other determining factors; fundamentally, increasing costs to parties also does not encourage investment. The Capacity Market was designed to keep capacity available and changes to balancing arrangements are unlikely to have significant enough impact on wholesale power prices to keep plant open. Under Objective (d), the introduction of a Loss of Load Probability calculation in order to then calculate a Reserve Scarcity Price to enter the cashout pricing stack would add significant complexity when STOR is used, for little if any apparent benefit. National Grid and the Workgroup have spent considerable time attempting to develop a workable LOLP calculation, yet not enough to show that such a process would be useful in practice. Rather it has confirmed that the market is highly reliable except when there is a plant failure, by nature unpredictable and difficult for other parties to respond to at short notice. Such additional complexity risks discouraging new

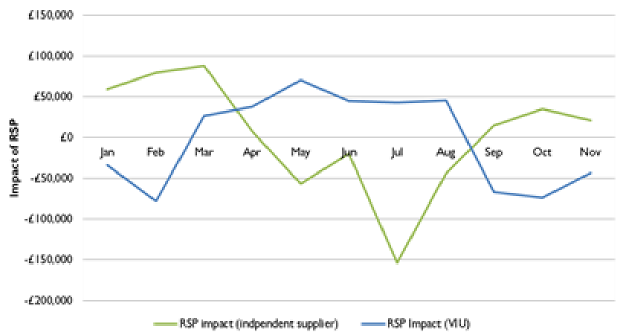
Respondent	Response	Rationale
		entrants while increasing the work and costs to existing parties and ultimately consumers to manage arrangements, a negative impact under BSC Objective (c). The market is also not helped by the general uncertainty arising from frequent/unnecessary changes to cashout. While the EBSCR may have been intended to bring an end to repeated changes to cashout, in practice arrangements will always have to evolve to account for other (technical, commercial and political) developments within and beyond the industry. The prospect that the EBSCR may introduce some complex changes, but that further alterations might shortly be made to comply with EU legislation (if required, currently not before some point in 2018 for the Electricity Balancing Network Code), is clearly unhelpful to parties attempting to manage their risk exposure. It would also be difficult for parties to have any confidence that a change determined in early 2015 to take place in Nov 2018 will actually happen, when any number of proposals could be raised in the intervening period to precede or unwind this. Consequently claims that P305 would aid competition by bringing some certainty seem optimistic. What is clear however is that with P305 would introduce unmanageable risk and potentially unintended consequences detrimental to Objective (c) (particularly if VoLL was introduced at £6,000/MWh). A party going out of business as a result of incurring excessive costs if short during a period when the market is particularly tight is a real risk of this proposal that would not benefit competition. Independent generators would also be particularly vulnerable to this situation. It has been suggested that it might be possible to obtain insurance to mitigate this risk, but clearly even if that is possible it will lead to parties incurring increased ongoing costs which will increase customers' bills. Also, for those able to manage increased volatility in costs/cashflow, the prospect of incurring extremely high costs in occasional periods could nevertheless wipe out any competitive benefit to parties who on the whole are 'better balancers'. If P305 is implemented, the fact that some parties might lose far greater amounts through rcrc than their own imbalance costs suggests that the process would not effectively reward competitive/efficient

Respondent	Response	Rationale
		behaviour. It is unfair that any company should have to pass on higher costs to customers incurred as a result of the actions of other parties.
Stark Software International Ltd	-	No Response
Utilita	No	We do not agree that P305 as proposed would better facilitate the BSC applicable objectives compared with the current baseline. P305 has four elements, this submission only relates to two of those elements: (1) the introduction of a single imbalance price, which Utilita supports; and (2) the reduction of PAR Value from 500MWh to 50MWh upon implementation, before reducing further to 1MWh on 1 November 2018 ahead of the winter 2018/19 season which Utilita strongly opposes. We have previously set out our views on the better facilitation of the relevant objectives by introducing a single imbalance price. This response therefore concentrates on the adverse effects of reducing PAR Value. Utilita's views on these aspects of both P316 and P305 are the same, therefore sections of our submission are replicated. In relation to **BSC objective B** (efficient and economic operation of the transmission system), we believe that implementation of a PAR value of 50MWh and 1MWh will not provide material benefits in respect of BSC Objective B. Implementing marginal pricing can only provide benefits to the economic and efficient operation of the system where participants are able to respond to the price signals given. In the case of the imbalance price, the price signal is not available until after the event. Without sight of the imbalance price and with no ability to alter NHH demand in the short term, the suppliers cannot respond to marginal price signals. Generators will probably already have made their decisions to be available and higher cash-out prices will not induce them to return mothballed stations. Utilita considers that there is a flawed assumption incorporated in several of the recent modifications impacting imbalance prices, including P304, P314 in both formulations, P316 and this proposal, as generation remuneration, which would still be based on pay as bid, would not be affected. A generator

Respondent	Response	Rationale
		who spills when the system is short would still receive the MIDS price, whereas a generator who spills when the system is long would receive a lower price than under the baseline. There would be less incentive to over-generate and no impact on security of supply. Either way, the generator would not be able to predict with any certainty which circumstance would apply in advance. Most suppliers, particularly smaller independent suppliers, will have already hedged their positions, to the extent that they are able to do so, within the market. In addition, at times of system scarcity, liquidity is reduced: this leaves smaller suppliers particularly exposed to higher and more volatile imbalance prices, without the ability to respond effectively to the price signal. Reducing PAR (particularly to 50MWh and then 1MWh) is merely exposing them to an ex-post increase in costs which are difficult to forecast and price into contracts. The suppliers are simply not in a position to respond to the prices generated by the changes in PAR. As suppliers cannot respond to the signal, this proposal would not better facilitate objective B. Decreasing PAR should have the effect of incentivising market participants to go longer than they otherwise would have. While we note that the single imbalance price included in this proposal would reduce the level of risk significantly from that suppliers would face under dual imbalance pricing, the increase in supplier exposure from the PAR value reduction proposed in terms of balancing and credit cost increases should not be underestimated. To avoid additional and volatile imbalance costs, participants may make less efficient, but more predictable contracting decisions, ultimately increasing the cost to consumers of managing erratic spill volumes by the SO. Overall we believe the impact of P305 (elements 1 and 2) on objective B will be detrimental, especially given that commercial decisions by suppliers have already been made based on a different baseline. In relation to **BSC objective C** (competition in the generation, supply, purchase and sale of electricity), the proposal will expose all parties to less predictable and increased imbalance costs. The analysis previously included in the P314 consultation

Respondent	Response	Rationale
		demonstrated the distributional impact among trading parties of a reduction in PAR to 250MWh. However the directional conclusions from this analysis would be equally valid for a reduction to 50MWh then 1MWh. The analysis showed that the impact would not be expected to be equivalent across trading parties and hence would introduce competitive distortions. Smaller suppliers, especially independent non-domestic suppliers, and renewables generators will be relatively more exposed to imbalance prices than their larger competitors. This is most notable during times of system stress as identified in the analysis of changing PAR values, where on average smaller non domestic suppliers saw some of the greatest impacts during most system stress events which were analysed. As noted under Objective B, in addition at times of stress/scarcity, liquidity would fall unduly impacting non vertically-integrated players. The system may also tighten ahead of the beginning of capacity payments. Taking all these issues together, it is essential to ensure that smaller players who may not be able to access peak products are not competitively disadvantaged. Reducing PAR as proposed would be expected to both increase imbalance prices and reduce predictability. It is more difficult for smaller suppliers to forecast imbalance on less diversified portfolios, compounded by lower customer numbers, fewer forecasting resources and less customer data (given most domestics are still using non Smart meters). Thus the net impact of this change would be to impose relatively higher imbalance charges on smaller parties. The increased imbalance prices will result in increases to RCRC. As the RCRC mechanism redistributes imbalance charges to those players in accordance with volumes this increase income for larger players. The redistribution of (relatively) higher costs to smaller players and additional income to larger players through RCRC would create a competitive distortion. Increasing imbalance charges will lead to increased credit requirements which is a direct barrier to new entrants and a significant drain on the capital resources of smaller players. Higher balancing costs will disproportionately impact

Respondent	Response	Rationale
		smaller suppliers who will inevitably have a greater proportion of their demand in balancing. This is not because smaller suppliers increase risk, it simply reflects trade sizes, portfolio stability and practical limitation on demand forecasting accuracy relative to larger players. National Grid as NETSO should balance the national aggregate position, with robust incentives to minimise balancing costs for the benefit of all and transparent reporting. If this is not the case this will lead to inefficient costs and all customers paying more than is necessary. Higher imbalance prices as a result of a reduction in PAR to 1MWh would also impact NETSO activity. Utilita therefore considers that reducing PAR value as proposed would not better facilitate objective C, even with the mitigating impact of the single imbalance price proposed. In respect of **BSC Objective D** (promoting efficiency in the implementation and administration of the balancing and settlement arrangements), Utilita considers that P305 will not better facilitate objective D. Credit provision is already a significant cost in the industry, particularly to smaller players. The reduction in PAR would be expected to increase imbalance prices significantly. This in turn will increase credit requirements and costs for all players compared with the existing baseline. The increase in imbalance prices and reduced predictability would also lead to additional administrative and analytical costs, especially on smaller, less diversified portfolios. This increased burden relative to the status quo would not improve efficiency in the implementation and administration of the credit arrangements needed. On this basis Utilita does not consider that P305 implementation would better facilitate objective D.
Cornwall Energy	No	We do not believe P305 will better facilitate the applicable BSC objectives, specifically in relation to objectives C (promoting effective competition in the generation and supply of electricity); we are concerned the reforms will have a number of impacts which will not be evenly distributed. Increasing the price of imbalance through making PAR more marginal will have a greater impact on smaller parties under dual pricing as a result of their

Respondent	Response	Rationale
		inability to trade and lower level of sophistication. The single imbalance price proposal mitigates this impact, but all of the analysis presented with this modification is based on historic assessments and does not take into account behavioural change. The benefit for smaller suppliers arises from the number of periods these suppliers are in imbalance in the opposite direction to the system. However, we are concerned this does not hold true for peak periods of the day and that in the future they may find themselves exposed to higher prices without the ability to trade, as liquidity shrinks at during system scarcity, and without the ability to trade internally like the vertically integrated utilities (VIUs). As the system is likely to become tighter between winter 2015 and the beginning of the Capacity Market payments it is crucial that companies who are unable to access peak power products are not put at a competitive disadvantage. Using the data supplied by Elexon for the net impact of charges on parties under Par1MWh, single pricing and the Reserve Scarcity Price (RSP) function (which is only available for January to November 2013) shows that the impact of RSP, which ascribes a notionally high value to the use of non-BM STOR, impacts independent suppliers more than others, and is a net benefit to VIUs. The chart below shows the net impact of RSP on both independent suppliers and VIUs. The total net impact of RSP on smaller suppliers is an increase in charges of £33,000 and for VIU the net impact is a reduction in charges of £25,000. There is also a seasonal impact, with the impact of RSP being highest in winter (when margins are tighter), while VIU's benefit from their integrated position by seeing the highest benefit of avoiding RSP in the winter.  As has been noted before, these changes will increase the credit requirements for parties, which will be required to collateralise exposure to higher prices. The increase in credit requirements and

Respondent	Response	Rationale
		imbalance charges will be significant to new entrants, a number of small suppliers have to be completely exposed to cash-out up to a certain size before they can start trading. Any increase in cash-out charges and credit requirements (which are substantial across the industry) will be a detriment to competition. Our preference would be to see single imbalance pricing and an appropriate PAR value introduced, which would be subject to review by the Panel to ensure there are no undesirable market impacts. Implementation of the more complex aspects of EBSCR, in particular the Reserve Scarcity Pricing function and including costs for disconnection require more detailed analysis of future impacts, including behavioural changes before they should be included as part of the BSC.
EDF Energy	No	EDF Energy is supportive of the overall goals of P305, and believes that some aspects of the proposed modification have merit. However, we do not believe that the modification, as it currently stands, should be approved. EDF Energy supports the introduction of a **single cashout price**, although we have some concerns that this could negatively affect within-day liquidity as described in response to Question 16. On balance, we believe that this would have a positive effect against BSC Objective C. We believe that a reduction in **PAR to 50MWh, and more importantly to 1MWh**, is inappropriate, due to the potential for volatility due to granularity at the balancing margin, and anomalous effects of real physical balancing on half-hourly trade imbalance. We feel that a value of 100 MWh value would mitigate these concerns and would be more appropriate, at least until there is more experience of behavioural changes resulting from Electricity Balancing Significant Code Review (EBSCR) changes. This is discussed in Question 7, below. Detailed Solution Area C on **Loss of Load Probability (LOLP) and Reserve Scarcity Pricing (RSP)**, and Area D on **Demand Control**, are complex, with the robustness of the LOLP calculation still not fully proven and the accuracy and merits of adjusting supplier positions for demand control uncertain. We note that LOLP &

Respondent	Response	Rationale
		RSP would rarely be significant and Demand Control will be called into action extremely infrequently. We therefore have concerns that the level of complexity and costs introduced may outweigh any benefits that these sections might bring, having a negative effect against BSC Objective D. This is discussed under questions 10 and 12 below.
Co-Operative Energy	No	Co-Operative Energy is of the view that, while the introduction of single-priced cash-out will assist competition by removing the existing asymmetric risk that the current dual-priced cash-out regime creates, this improvement will be outweighed by the disbenefit to smaller, non-vertically integrated participants (and thus effective competition) which the significant reductions to the PAR value proposed for Winter 2015 and Winter 2018 will create. This is due to the fact that smaller participants who do not hold generation assets are unable to use these to hedge their short term imbalance risk in the same manner as their larger vertically integrated competitors. Also, they do not benefit from the potentially significantly increased cash-out prices which the proposed PAR reductions will create in tight network situations as they cannot sell generation output into the balancing mechanism in order to benefit from these in the same manner as larger vertically integrated participants. Given these factors we believe that the proposed PAR reductions will create an even less level playing field than that which currently exists between participants with no access to generation and participants who hold generation assets.

Question 2: Do you have a preferred solution option that you believe should be progressed as an Alternative Modification?

Summary

Yes	No	Neutral/No Comment	Other
17	10	3	0

Responses

Respondent	Response	Rationale
Western Power Distribution	Neutral	-
ScottishPower	Yes	ScottishPower's preferred Alternative Modification would have the following features: PAR set to 50MWh on implementation; At a future date once the market has had time to adapt to the more volatile and extreme cash-out prices, the impact on market behaviour can be assessed and the justification for a move to fully marginal pricing (PAR=1) can be examined. All other aspects remain the same except; STOR actions to be priced into cash-out using a Reserve Scarcity Pricing function using VOLL (as above) plus a LOLP based upon the "static LOLP" function proposed in the Consultation.
IMServ (Europe)	No	We have no comments to make here
TMA Data Management Ltd	No	-
Drax Power Limited	No	Not at this time, at least for all four of the main components of P305. However, a PAR value in the range of 50/MWh – 100/MWh appears more appropriate than the adoption of PAR1 (please see answer to question 7 for further details) and should be incorporated into an Alternative Modification. Further development of the options considered to date by the Workgroup (especially on the RSP Function) and evaluation of historical data is required before we are able to provide a definitive view on our preferred Alternative Modification.
GDF SUEZ UK-Turkey	No	GDF SUEZ would support an alternative to the proposed modification as described below but it is recognised that this solution would not fully address the defect set out in the modification proposal.

Respondent	Response	Rationale
		Firstly, the RSP function should be removed from the modification and the current STOR adder to the BPA retained. Secondly, GDF SUEZ would like to see voltage reduction not counted as demand disconnection. This is because of the marked difference between that instructed by Grid and that delivered. When voltage reduction is instructed, the amount delivered will depend on the time of day (early in the morning and at weekends there may not be the load to respond) and the type of load. Motors or LED/fluorescent lighting (inductive load) for example will simply take more current and after a brief dip in offtake, will consume the same power as before. A resistive load such as heating or tungsten lighting would fully respond. Because of this, the SO will call for more voltage reduction than it actually needs. To better illustrate this, it is worth referring to the report that National Grid issued following the frequency deviation and automatic demand disconnection event in May 2008. See http://www.nationalgrid.com/NR/rdonlyres/E19B4740-C056-4795-A567-91725ECF799B/32165/PublicFrequencyDeviationReport.pdf Had this instructed volume fed into cashout it may have had a very big impact on the cashout price. Inclusion of voltage reduction in the demand disconnection volume could therefore cause cashout prices to rise to unnecessarily high levels despite consumers potentially having suffered little discomfort. Since the above two aspects are listed as "Defects that Modification Proposal Seeks to Address ", GDF SUEZ understands that they must form part of the modification in some form and cannot be removed. Without a viable alternative to the current BPA for incorporating Reserve Pricing, it is not possible to suggest an alternative modification.
RWE Supply and Trading GmbH	Yes	We support the progress of an alternative that includes a static LOLP calculation that reflects the system margin or demand fundamentals.
SmartestEnergy	Yes	It is argued in the consultation document that because P217 revised the tagging process after PAR was increased from PAR100 to PAR500, the next

Respondent	Response	Rationale
		logical step is to move to PAR 50. We are concerned about the prospect of moving to a PAR50 and then to 1 when there are other changes being simultaneously proposed such as the RSP and Demand Control. As highlighted in the consultation document (page 22) there is also the potential issue of sub-optimal decisions made by NGT affecting prices in several successive hours. We would prefer to see a static PAR100 introduced alongside single cash out and any further reductions being the subject of another modification. We are not uncomfortable with the dynamic LOLP calculation and this appears to be the correct thing to do.
Flow Energy	No	-
InterGen UK Ltd.	Yes	With regards PAR, InterGen is supportive of the P305 proposed solution of reducing to PAR 50 during Winter 2015 and subsequently PAR 1 by 2018. InterGen has also expressed its support for P316 to be implemented (with PAR 50 by Winter '15) and would urge that this is considered alongside P305 as a practical alternative, given the complexity of some of the P305 proposals. InterGen believe that there is a real danger that the implementation of P305 could be delayed as industry struggle to land on a workable solution to calculating LoLP ahead of Winter '15. Implementing the P316 proposals (reduced PAR, single cashout price) could ensure that the benefits of sharper cashout can be realised this year, and gives industry more time to consider fully the more complex proposals outlined in P305.
National Grid	No	As the Proposer of P305 we do not have a preferred solution that should form an Alternate. However we recognise that there are alternative options available for the PAR and LOLP solutions that may deliver similar benefits to the lead proposal, we have provided our thoughts on these options in our responses to questions 7, 8 and 9 below.
DONG Energy	No	DONG Energy does not believe that any of the solutions set out in the "Assessment Procedure Consultation" document would better facilitate applicable BSC objectives due to the reasons explained in response to Question 1.,We support a solution that incorporates a high PAR and a LoLP that is determined one hour ahead of gate closure as this gives market participants the chance to adjust their trading strategy to tighter margins knowing what the RSP might be and to avoid some

Respondent	Response	Rationale
		of the risk exposure from high LoLPs. This has the potential to improve the cost reflectivity of the market without disproportionately penalising certain groups of market participants and therefore better facilitates BSC objective C. Although there has been previous analysis DONG Energy does not feel that the range of options that have been considered was exhaustive and would like to see scenarios considering different timelines of introduction with staggered approaches and higher PAR values, e.g. PAR450.
Good Energy	Yes	We believe that the following package, based on the various options already under consideration by the Workgroup, implements the four main elements of P305 that stemmed from Ofgem's Electricity Balancing Significant Code Review but addresses our main concerns with P305 set out in response to Question 1 and, taken overall, better facilitates the Applicable BSC Objectives: 1. Introduction of single cash out prices as proposed for P305; 2. Reduction in PAR to 250MWh upon implementation and then to 100MWh 12 months later – with RPAR set at 1MWh upon implementation as in P305; 3. Introduction of Reserve Scarcity Pricing as proposed in P305 but using the 'static' LoLP function being developed by the Workgroup and with VoLL introduced at £2,000/MWh and remaining at that level for at least 2 years while parties gain experience of the changed market conditions and it becomes clearer what happens to market liquidity when potentially very high imbalance prices are expected, with any further increases to VoLL being initiated by the proposed VoLL review process; 4. Introduction of pricing for Demand Control actions as proposed in P305. Referencing each of the four parts of the proposed package to how we consider they facilitate the Applicable BSC Objectives: Part 1: Promotes more efficient balancing by parties (d) thereby reducing balancing undertaken by Transmission Company (b); appears to benefit smaller parties (c).

Respondent	Response	Rationale
		Parts 2 & 3: Sharper cash out prices from lower PAR & RSP but with diluted impact of flagging/tagging concerns & lower VoLL promotes more efficient balancing by parties (d) thereby reducing balancing undertaken by Transmission Company (b); rewards flexibility (c: generators) offset by adverse impact of extreme events on smaller parties (c: generators & suppliers but ameliorated by phasing); Part 4: Pricing for Demand Control actions & correction of parties' imbalance positions (d).
Centrica	Yes	We support the introduction of a higher PAR value within the range of 100-200 MWh. If a phased approach is deemed to be consistence within the alternative we would support an initial reduction to 200 MWh from November 2015 with a further reduction down to 100 MWh from winter 2018. This betters applicable objective b - the efficient, economic and co-ordinated operation of the National Electricity Transmission System as market participants will be better able to forecast the imbalance costs and balance their position accordingly. Additionally, we support the adoption of a static LoLP function rather than the dynamic one that we consider still requires significant development and further testing against historical data.
RenewableUK	No	RenewableUK does not have a specific Alternative Modification to propose, but we would press for options involving higher PAR values such as 450 or 350 to be investigated to assess their benefits and impacts.
Electricity North West	Yes	We would prefer a 'top down' approach. We have not received a response to our 'top down' approach mentioned in Q5 of the previous consultation. In addition to this, there hasn't been a response to the point we raised in Q8 of the previous consultation with regard to while it is recognised that a 'bottom up' approach is likely to improve the accuracy of calculation, this seemed to be a significant upfront cost to the industry and impact a number of market participants, so it would be worth understanding what granular improvement in the level of accuracy, when measured against the 'top 'down' approach, is likely to be attained if such costs are justified. If the 'bottom up' approach is still to be progressed we do not believe that Distributors should need to

Respondent	Response	Rationale
		send new Dataflows for the rare occasions when these occur. This should be provided through reports to the relevant parties.
VPI Immingham	Yes	We would suggest moving directly to a PAR of 1MWh as an alternative solution. As outlined in our response to question 1, this would sharpen the price signals associated with balancing and hence incentivise participants to balance their position ahead of gate closure. This should therefore incentivise trading and improve liquidity in the market. In addition, this would also resolve the issue associated with P316 and P305 running consecutively as separate modifications. Should P316 be implemented ahead of P305 and hence PAR move to 1MWh, then PAR would not change back to 50MWh should P305 then be implemented.
UK Power Reserve Ltd	Yes	We believe that PAR 1 alongside a single price is the priority for implementation and therefore P316 enables these priority principles to be implemented as soon as is possible and no later than 5/11/15. We agree with the modification proposal P305 however have a concern if that complexity of inclusion of some of the principles may delay implementation and that perhaps P316 better serves the industry in the near term with further changes to take place in line with P305 at a later date.
Green Frog Power	Yes	Yes: the changes the move to single pricing and PAR1 should be brought in as per P316 and the remainder of cash-out reform contained in P305 should be brought in as soon as possible.
Vattenfall	No	-
Eggborough Power	-	-
Haven Power Limited	No	We have made some suggestions in Q1 for how we think the solution might be better implemented. At this time we do not wish to formally propose an Alternative Modification.
SSE plc	Yes	a) Single price from 2015; b) PAR 50 2015 moving to PAR 1 in 2018; c) RSP from 2015, using a static LoLP function and de-rated margin signal that the market can

Respondent	Response	Rationale
		respond to and risk manage; d) VoLL of £3000/MWh from 2015 rising to £6000/MWh from 2018 e) A good-behaviour incentive upon market players to continue contracting flexibility products even as margins tighten further and Demand Control probability increases. Currently this is in the form of an artificial volume estimation calculation and adjustment of imbalance position; however SSE have concerns that this process could inadvertently impact Suppliers by leaving their position short even though they have responded rationally and correctly to all available signals. Could this be better incentivised through license condition with partial financial adjustment? f) If a volume adjustment is the only reasonable incentive that can be devised, then we support the working group conclusion that it ought to be as robust and equitable as possible.
First Utility Limited	Yes	Because of the concerns raised above, our preferred solution (of the alternatives described as part of this consultation) are that from 5th November 2015: • 250 MWh PAR, reducing to 100 MWh after twelve months • 24 hour ahead static LOLP
E.ON	Yes	While we do not believe that there is a clear case for change, an Alternative to reduce PAR to 100MWh or 50MWh in 2015/2016 with no definite step in 2018 would be preferable. This would allow more time for parties to make any adjustments possible to a new regime and for a considered review of the impacts as well as further consideration of other developments, to determine the advisability of raising any further change e.g. in 2016/2017 to take effect in 2018. It seems unlikely that (LOLP and) RSP would make a significant difference to behaviours or costs; whatever LOLP methodology is used the accuracy is unlikely to be trusted until the final figure is produced, when parties have limited ability to respond.
Stark Software International Ltd	-	No Response

Respondent	Response	Rationale
Utilita	Yes	Utilita supports the introduction of a single imbalance price and supports the views of the workgroup on this aspect. However Utilita opposes the reduction in PAR to 50MWh and then 1MWh. On this basis we believe that an acceptable alternative within the scope of P305 would be to implement a single imbalance price without changing PAR. However, as noted elsewhere in this submission and in our submission in respect of P316, Utilita believes that the impact of this change, in conjunction with the introduction of the capacity mechanism and CfDs, should be monitored and evaluated before further change is proposed to imbalance prices or PAR.
Cornwall Energy	Yes	Alternative PAR options – of all the alternative PAR options proposed we prefer a phased approach starting at 250MWh and reducing to 100MWh twelve months later. We believe giving parties time to experience and learn from lower PAR values would benefit the industry. We agree with the concerns raised by the workgroup that a 1MWh PAR value could end up including incorrectly tagged or inefficient balancing actions and raise the cost of imbalance unnecessarily. Alternative LoLP function – we prefer the alternative static LoLP function as the dynamic function is too complex, leading to concerns about its impact on smaller participants and new entrants. A fixed function would be easier to understand and model for new and smaller less sophisticated participants.
EDF Energy	Yes	EDF Energy's preferred Alternative Modification would have single price; a PAR value of 100 MWh with no pre-determined subsequent change; a value of LOLP fixed at Gate Closure using the proposed static LOLP function; estimation of total demand control volume and pricing at VOLL in cashout, but without the complication of adjustment of supplier imbalance position. We think this would meet BSC Objectives better than the proposal. The rationale for this position is discussed in subsequent questions.
Co-Operative Energy	Yes	We believe that the least worst of the available options is the proposal to reduce PAR to 250MWh upon implementation followed by a reduction to 100MWh 12 months later. While our concerns listed above in relation to the effect of PAR reduction still

Respondent	Response	Rationale
		stand, we believe that the adoption of less reduced PAR values than those currently proposed may go some way towards lessening the negative impact on competition should these be implemented as currently envisaged. However, our preference would be for single-priced cash-out to be introduced separately in November 2015 with any reduction to PAR being introduced not less than twelve months later in order to allow the market to adjust to this change and appropriate analysis in relation to the effects of this to be made.

Question 3: Do you believe that there are any other potential Alternative Modifications within the scope of P305 which would better facilitate the Applicable BSC Objectives that the Workgroup should consider?

Summary

Yes	No	Neutral/No Comment	Other
13	13	3	1

Responses

Respondent	Response	Rationale
Western Power Distribution	Neutral	-
ScottishPower	Yes	ScottishPower's preferred Alternative Modification would have the features identified at (2) above. Parties and markets require time to respond to a move to more marginal and hence more volatile cash-out prices. If Parties are unable to respond rationally and reflect changes in cash-out price in their economic decisions then the change will not deliver increased efficiency in the market arrangements. We believe that PAR should be set to 50MWh on implementation. A post-change review should be carried out at a future date to determine whether the benefits from a move to PAR = 50MWh have been delivered following which any Party would be able to raise a Modification for a further reduction for example to PAR = 1MWh. Similarly, unless the calculation of LOLP produces a reliable signal of tightening system margin and potential demand reduction, Parties will be unable to respond and trade to adjust their positions. The Proposed "dynamic" function does not appear to deliver a predictable signal and could therefore lead to Parties trading inefficiently thus our preference is for the "static LOLP" function.
IMServ (Europe)	Yes	A viable alternative would be for the DNO to produce the DXXXX and DYYYY flows. This has the advantages that – No DWWWW flow would be required, The potential for the wrong agent to be notified would not exist, The DNO already holds HH consumption data,

Respondent	Response	Rationale
		A change of HHDC or HHDA would have no negative impact, The estimation methodology is simple and only requires previous HH data NHH sites in PC1 to 4 may have minimal impact on Settlement and may be able to be excluded from the process. We recommend that ELEXON reviews the reference data used to justify the modification proposal in order to quantify the volume of impacted NHH sites and business case for inclusion of such in the process. N.B: In this context we are referring to PC1 – 4 only as, PCs 5 – 8 will move to HH settlements under P272 and would therefore be covered under the suggestion described above.
TMA Data Management Ltd	No comment	-
Drax Power Limited	No	The Workgroup is considering a range of solutions which appears to be sufficient for the development of P305. Whilst it is possible that other solutions exist, we are not aware of any at this time. However, there may be merit in exploring a solution which restricts the application of a single price to the smallest parties only.
GDF SUEZ UK-Turkey	No	-
RWE Supply and Trading GmbH	No	-
SmartestEnergy	No	-
Flow Energy	Yes	P316, please see our response to P316
InterGen UK Ltd.	No	No alternatives with respect to P305, but we support the implementation of P316 as outlined above.
National Grid	No	-
DONG Energy	Yes	As stated in response to Question 2, DONG Energy supports a solution that builds on higher PAR values than the ones currently proposed, namely PAR450 or PAR350 with a staggered implementation. However, any change should be assessed in the way suggest under response to Question 1. Furthermore, we would welcome an assessment of potential further benefits from reduced gate closure

Respondent	Response	Rationale
		time which from our point of view can reduce forecast errors for variable generation and demand forecasts and contribute to balancing efficiency and ultimately positively affect the objectives that are aimed for with this modification.
Good Energy	No	Having considered the arguments presented by the Workgroup we are of the view that our preferred solution set out above is the best package in terms of facilitating the Applicable BSC Objectives that is consistent with implementing the four main elements of P305 that stemmed from Ofgem's Electricity Balancing Significant Code Review.
Centrica	No	-
RenewableUK	No	-
Electricity North West	Yes	Please see our response to Q2.
VPI Immingham	No	-
UK Power Reserve Ltd	Yes	Please see response to Question 2.
Green Frog Power	Yes	The benefits of a single price appear to be agreed by everyone, including ourselves, so we will not belabour this point. Even without a change to the PAR volume we think this is an obvious improvement on the current, lopsided, pricing mechanism. It is unclear to us why such a high PAR volume is in use at all, and it is not convincing to us that a slow change to the correct price signal would benefit the functioning of the market in any material way. The analysis supports the view, and the workgroup agrees, that the impacts in the reduction of PAR volumes is non-linear, so it is unclear what benefits slow change to the final improved model would bring. From our perspective, as a small generator struggling to enter the wholesale market, we believe that the muted price signals benefit large players with large positions hedged well in advance. These large players will be most inconvenienced by a change to more marginal pricing (in the context of single pricing). Elexon's own analysis demonstrated that smaller players, suppliers in particular, will not be unduly inconvenienced by a change to a lower PAR volume so long as it is in conjunction with a

Respondent	Response	Rationale
		change to a single price. Delaying a change to sharper pricing of peak periods during a next couple of winters, when we are expecting tighter margins than seen for some time, could signal a lack of commitment to designing an efficient system that facilitates the restoration of the missing money to the market. This could result in an unnecessarily high capacity price in the next few capacity auctions. If market participants do not believe that the energy market will provide the appropriate level of reward, they will bid a higher capacity price. This is a particular risk with a phased reduction in PAR, since bids four years in advance will reflect the risk weighted forecast of energy margins that lack sight of the impact of the PAR volumes in effect in the delivery year. In total, it is very difficult for us to see any benefit of a phased approach to reducing the PAR volumes, nor in delaying them. We believe that the proposed incremental PAR volume reduction could be counterproductive to the long-term goals and that a move to PAR1 should be made in one step. Our preferred alternative option after P316 is an alternative modification proposal with single pricing and PAR25 with the intent of moving to PAR1 as soon as possible thereafter.
Vattenfall	Yes	Vattenfall agrees with the opinion of the workgroup, which supported staggered and phased reduction approaches, allowing for analysis to be undertaken before lowering the value further. Although this might create uncertainty in industry about whether the next step would take place, it would allow mitigations to be put in place which are relevant for each reduction in PAR. The report notes that impacts from the reduction in PAR is 'not linear, and are likely to get steeper as the PAR value gets closer to 1MW'. It might be that PAR50 achieves the aims of P305 without the need to further reduce to PAR1. Selecting a higher PAR might help to uphold the relevant BSC objective C, by not having such a significant impact on some parties over others – notably small intermittent generators. In order to provide some clear path of reduction, Vattenfall supports the approach of outlining the steps of PAR reduction, and making clear the metrics against which the move to the next PAR will be judged. This will enable industry to plan for likely

Respondent	Response	Rationale
		further reductions in PAR, and should address the issue of inefficient implementation/dilution of outcome.
Eggborough Power	No	Eggborough would prefer to see a slightly higher PAR value initially used in P316 before moving to a simple marginal price. While there are benefits in simplicity, using the volume weighted average of the most expensive 50 MWh may be a better initial starting point. We believe that such an alternative could remove any really extreme prices that could arise and make the prices more predictable. For P305 we would suggest the static LOLP may be more robust, but feel the whole mechanism needs further development. Our concerns are that the signals given cannot be responded to and are therefore useless. However, as noted above, we would rather see this dealt with under a new modifcaiton.
Haven Power Limited	Yes	We believe that the workgroup should consider a modification that increases the incentive on parties to balance while offering protection to very small parties that are unable to trade their position into balance. We suggest that this may be solved by only offering single cashout prices to very small parties.
SSE plc	Possibly	See above comments regarding artificial calculation and adjustment of Supplier volumes and imbalance positions. Could a good behaviour license condition suffice?
First Utility Limited	Yes	We believe that some of the adverse distributional effects of this modification could perhaps be addressed by a review of the RCRC mechanism.
E.ON	No	-
Stark Software International Ltd	-	No Response
Utilita	Yes	A further alternative would be to implement a single imbalance price in conjunction with a modest reduction in PAR to 350MWh as previously proposed. However if this approach were taken, we believe that its impact post implementation should be carefully monitored to assess the combined change (of single imbalance price and reduction in PAR to 350MWh) in conjunction with the wider changes to

Respondent	Response	Rationale
		the industry (implementation of a capacity mechanism and CfDs under EMR) prior to considering further change under a new modification and working group.
Cornwall Energy	No	-
EDF Energy	Yes	See response to Question 12. We think an alternative without adjustment of supplier volumes for demand control would be simpler to implement, better meeting BSC Objective D, and preferable to the proposal in not presuming uncompetitive windfall gains for affected suppliers under demand control, better meeting BSC Objective C.
Co-Operative Energy	Yes	As mentioned above, vertically integrated participants can use the generation assets they hold to hedge their short term imbalance risk and also to generate additional revenue from selling generated output into the balancing mechanism. Non-vertically integrated participants are unable to hedge this risk in this manner and are denied access to this alternative revenue stream from the balancing mechanism due to their lack of generation assets. This will therefore directly affect their ability to compete on a level playing field. Any reduction to PAR should be based on thorough, publicly available analysis and implemented separately following the implementation of single-priced cash-out and a period of not less than twelve months to allow analysis of the effects of this. We would therefore suggest that single-priced cash-out be introduced as planned in November 2015 with reduction of PAR to a level to be determined following the necessary analysis in order to avoid negatively impacting competition to be introduced in Winter 2016.

Question 4: Do you agree with the Workgroup's recommended Implementation Date?

Summary

Yes	No	Neutral/No Comment	Other
17	12	0	1

Responses

Respondent	Response	Rationale
Western Power Distribution	No	In line with our response to the impact assessment issued last year we do not agree with a November 2014 implementation date. This modification will potentially involve changes to SMRS and a November 2015 implementation will potentially clash with Registration Data Provision (RDP) testing required for implementation of Smart Metering. In addition, as DTC changes will be required and these have still not been put forward in to the MRA change process, it is possible that these will not be approved in time for a November 2015 implementation. As stated previously we would prefer a June 2016 implementation date. This deferred date is also likely to be the earliest achievable implementation date if requirement 5.4 is implemented in its' current form. Please see response to question 5 for more detail on this.
ScottishPower	Yes	Parties require as much notice as possible that the changes to electricity cash-out prices embodied in P305 will be implemented from a firm date. This will enable Parties to manage their contract positions (generation and supply) in the certain knowledge of which cash-out regime will be in force. We agree that implementation on 5 November 2015 in line with the scheduled BSC Systems Release would allow the changes to be implemented ahead of the winter 2015/16 season in an efficient manner
IMServ (Europe)	No	The lack of both clarity and detail prevents us committing to be able to implement this proposal by November 2015. Until we know the detailed requirements, we cannot: Modify our processes and systems Agree commercial arrangements with Suppliers for providing this service on their behalf. Our detailed concerns that require thought /

Respondent	Response	Rationale
		clarification are detailed under question 16. When previously asked how long would we need to implement these changes our response was 12 months and we have no reason to change this view. Our and other Agents ability to manage the implementation of these changes in addition to all the other significant industry changes scheduled for November such as EMR and P300, is extremely unlikely, particularly while the exact requirements are so vague. Furthermore, the changes already timetabled under P300 for November include updates to the main HHDA settlement reporting flows. The process of implementing this current modification (P305) would require development and testing of the same flows and areas of the database used for this HHDA settlement reporting. It is not possible to safely or successfully implement two separate sets of changes concurrently (by multiple parties across the industry) without a significant risk to settlements.
TMA Data Management Ltd	No	Please see response to question 16.
Drax Power Limited	Yes	This is in line with Ofgem's recommendation contained within the EBSCR Direction. However notwithstanding this, a longer implementation timescale would provide market participants with more time to prepare for the new imbalance arrangements. Better aligning implementation with typical trading timescales would facilitate more efficient trading behaviour.
GDF SUEZ UK-Turkey	Yes	GDF SUEZ agrees with the proposed implementation date of 5th November 2015 provided that Ofgem provides at least 6 months notice that the modification will be implemented. This lead time is needed to allow suppliers to reflect changes in their pricing and also to any supply or PPA contracts that are linked to the current cashout arrangements.
RWE Supply and Trading GmbH	Yes	P305 should be implemented as soon as practicable.
SmartestEnergy	Yes	We are still concerned about the fact that a short lead time creates uncertainty in the market. November may be acceptable but we could do with knowing now for certain that the change will be implemented. The consultation document suggests that P316

Respondent	Response	Rationale
		could be implemented before P305: "the Workgroup has noted the possibility that P316 could potentially be implemented ahead of P305 to ensure delivery of the single marginal price parts of the EBSCR separate to (and possibly earlier than) the RSP and Demand Control parts." However, they could also be the other way round with P305 implemented in November with a higher PAR value, say 100, with P316 used to reduce PAR further, say to 50.
Flow Energy	Yes	-
InterGen UK Ltd.	Yes	InterGen would urge that in order for any transitional PAR reductions to be fully effective, the trajectory should be concluded and implemented in as swift a timeframe as possible. InterGen preference therefore would be to implement a PAR reduction at the start of Winter 2015 (1st October) but would still be able to secondarily support a 5th November 2015 implementation date if that was the majority preference and would prevent further delay.
National Grid	Yes	This aligns to the November 2015 BSC Systems Release and follows the aspirations set out in Ofgem's Final Policy Decision that the reforms are implemented ahead of the winter 2015/16 season.
DONG Energy	No	DONG Energy believes that the recommended implementation date 5th of November 2015 would be possible from an operational point of view. However, an implementation date after Winter 2015 would give market participants the opportunity to adapt to the new market environment during the summer before higher stress events occur in Winter 2016. Furthermore, as there is still significant work to be done with regards to further impact assessments and the design of an appropriate LoLP we believe that an implementation in Mid 2016 would provide the time needed to fully develop a package of changes that can achieve the goals of the Significant Code Review in the most effective and efficient way.
Good Energy	Yes	We agree with the recommended implementation date as part of a phased approach to change, as set out in response to Question 2, to allow parties time to adjust and gain experience of a market with sharper imbalance prices.
Centrica	Yes	We support the proposed implementation date of 5th November 2015 for the introduction of the

Respondent	Response	Rationale
		alternative to this modification.
RenewableUK	No	From the point of view of variable renewable generators, reductions in PAR will be a significant change which would need preparation and time to bed in. To have this introduced as the wind generating season approaches its peak, and thus wind generators are at highest risk of being exposed to balancing charges, appears unfair. Such generators would also have only a few months to put in place new mitigation, which is likely to be complicated and expensive. We would prefer any reductions in PAR to be ahead of the summer season so wind generators can build up experience of the new conditions before being exposed to higher balancing risk.
Electricity North West	No	Based on the solution contained within this consultation the implementation date of the November 2015 release is unlikely as a consequence of introducing new Dataflows and sending such Dataflows from the SMRS system. Such changes require a lead time of 6 months and would need to be submitted to the May 2015 Market Development Board in order to achieve the November implementation date. Added to this there is significant activity as a consequence of the smart meter roll-out and the introduction of the DCC which will impact this implementation date. If a 'top down' approach or a 'bottom up' reporting solution rather than Dataflow production is adopted it is more likely that the implementation date could be achievable.
VPI Immingham	Yes	We agree with the proposed implementation date as we believe that these changes should be implemented sooner rather than later to better facilitate the applicable BSC objectives. We wish to see the move to a single marginal price and a sharper PAR ahead of next Winter, when capacity margins are expected to be tighter, as demonstrated by our support for P316. However, it is essential that the LoLP and Demand Control mechanisms are robust and fit for purpose. Therefore, should these not be deemed suitable within the required timeframes, then we would support separating the package into different components to avoid delay in the implementation of the components that are ready.

Respondent	Response	Rationale
UK Power Reserve Ltd	Yes	We agree with the intended implementation date although would support any move to implement these changes sooner as we feel they are greatly beneficial to the industry and that any delay is merely delaying the introduction of these benefits, particularly with the predicted tight margins of generation over the following winters. The sooner a reflective price signal is evident in the market the sooner the market is encouraged and incentivised to act smarter and more efficiently to the benefit of the end consumer.
Green Frog Power	No (too slow)	The sooner the elements of P305 that are not contained in P316 are brought in the better. The market has for many years been distorted by incorrect pricing signals, which will be fed into the next Capacity Market auction bidding strategies and the final clearing price, at enormous cost to the consumer.
Vattenfall	Yes	Vattenfall agrees with the implementation date, with the caveat that the move to PAR1 is not automatic, but supported by analysis. This analysis would need to show that the negative impacts to intermittent generators and other groups of industry players, as well as any change in the incidence of negative pricing is outweighed by the perceived benefit of a further reduction in PAR. Making a slower transition to PAR1 than is suggested under P316 gives the opportunity for transition arrangements to be made for smaller players who are likely to be impacted by the more extreme marginal price of balancing.
Eggborough Power	No	P316 will be straight forward to implement and the November date would also allow parties time to prepare for the changes. The P305 timetable looks too ambitious given the scale of the changes. In particular the elements that may impact parties' positions with their customers may require significant commercial renegotiations.
Haven Power Limited	No	We appreciate that the implementation date is in line with Ofgem's recommendation contained within the EBSCR Direction. However, we feel that this is putting pressure on the need to push the modification though as soon as possible and without giving enough time for adequate consultation. We also do not believe there will be sufficient time between the final decision on the modification and

Respondent	Response	Rationale
		its date of implementation to allow market participants to prepare for a very significant change in imbalance arrangements. Better aligning implementation with typical trading timescales would facilitate more efficient trading behaviour. Furthermore, we think it would be much more preferable to implement the modification at a time when the system is relatively benign. See Q1 for our discussion on this.
SSE plc	Yes	SSE believes that it is important to ensure that a sharpened cash-out regime is in place for Winter 2015/16 to aid continued investment in flexible assets. 5th November is therefore an appropriate target date for implementation. Note that system changes are likely to require 4-6 months lead time, but the longer lead time changes are associated with the processes required to derive estimated volume adjustments in response to involuntary demand control events.
First Utility Limited	Yes	We agree with Nov 2015 for the reduction outlined in our response to Question 1 only (but would not agree this date for any further PAR reduction due to the concerns stated in our answer to Question 1).
E.ON	No	While a reduction in PAR later this year has been widely anticipated, parties have no certainty until an Authority decision is reached, as emphasized by the rejection of P304. After a decision it still takes time to adjust processes and behaviours, where this is possible. More lead time should be available with this proposal than was suggested for P304's PAR 250MWh and P314's 350MWh, and six months should be sufficient for us to make the necessary IT changes. Nevertheless this is still not a great deal of time to prepare for multiple, more significant changes to balancing arrangements; as others have noted it takes time for products to be developed to allow parties to manage their businesses effectively under a new regime, e.g. to hedge the increased risks. A particular concern with P305's Proposed changes this year is the number being suggested at the same time - Single Pricing and tightening PAR in themselves plus the added complexity of LOLP and RSP, further work for parties to handle though the latter ultimately only likely to apply to relatively few periods a year. We do not agree that a change for winter 2018-19 should be determined this early. It would seem

Respondent	Response	Rationale
		more prudent to monitor the impacts of any changes introduced in the next year or two, to balancing, other trading arrangements and beyond (e.g. CM auction repercussions, DSBR, SBR, CMA investigation outcome, general election result). This would also give more time for the nature and timescales of any European requirements to become clearer. If considered appropriate after monitoring the market, another change to balancing could be raised in 2016 or 2017, while parties retain the ability to raise a modification proposal at any time. So much is likely to have changed by 2018 that it cannot realistically be claimed that a decision in early 2015 to implement a change in November 2018 would provide market participants with any genuine certainty of future arrangements. The prospect of PAR 1MWh and VoLL at £6,000/MWh however could act as a deterrent to any parties considering entering the market. We note also that parties have not been able to assess the potential impact on them of VoLL being applied to Demand Control actions, or of £6,000/MWh being used in RSP calculations, as Elexon only provided RSP data based on £3,000/MWh and on Jan-Oct 2013 when no demand disconnection took place. It is undesirable for any decision to be made to introduce such measures without providing at least some projections/ simulated data to help estimate the potential impacts on parties, and for this information to feed into a decision.
Stark Software International Ltd	No	No. It is unhelpful for HHDC/HHDA to develop and implement changes coincident with those within P300.
Utilita	No	As under question 1, Utilita does not support the implementation of P305 due to the inclusion of the proposed reduction of PAR value to 50MWh and then 1MWh. On this basis we do not agree with the proposed implementation date.
Cornwall Energy	Yes	We agree with the 15 November implementation date to coincide with the November systems release. However if there is further delay to the EBSCR programme we would not like to see changes implemented in the middle of winter and would prefer to see a November 2016 implementation. Time will be required by

Respondent	Response	Rationale
		participants to amend contracts and tariffs ahead of the implementation of P305.
EDF Energy	Yes (with caveats)	We agree that the changes should be implemented as part of a regularly scheduled BSC release. We would require at least six months' notice to implement the relevant changes to our business systems, processes and procedures. We would note that a number of customer supply contracts for the period November 2015 onwards have already been signed across the industry. Implementation of these modifications may require suppliers either to reopen these contracts to take into account the new cashout calculations, or cause suppliers to take on additional risks which may not necessarily have been priced into the contracts when signed.
Co-Operative Energy	-	We do not support the PAR levels currently proposed in P305 due to the potential negative effect on competition. Please see our answers to Questions 1, 2 and 3 above.

Question 5: Will P305 impact your organisation?

Summary

Yes	No	Neutral/No Comment	Other
29	1	0	0

Responses

Respondent	Response	Rationale
Western Power Distribution	Yes	We will need to make system changes to allow us to automatically identify MPANS impacted by an instruction to shed/restore load and link them to our SMRS in order to identify impacted DC and DA parties and generate and send new DTC flows to them. Given the current, relatively low number of embedded connections likely to be impacted by this modification we will probably elect to introduce a new manual process to notify any embedded DSO impacted. However, this is an assumption as the assessment consultation (requirement D5.1) is silent as to what information needs to be sent to an impacted, embedded DSO and does not state whether information needs to be sent at the start of an event, at cessation of an event, or both. At this stage it is not clear that we can fully comply with the requirement number 5.4 This requires us to exclude MPANs registered as de-energised which is achievable using data in SMRS. However, as there is no fixed date for production of the DTC flow, the effective energisation status will be assessed at the point in time when the DTC flow is produced. Given that standard industry processes typically result in Suppliers updating the energisation status retrospectively this may result in inaccurate data being provided, unless there is a requirement to send updated information in the event of a subsequent retrospective update by a Supplier, Requirement 5.4 also requires us to exclude deregistered MPANS and the accuracy of this data is also subject to the issue of retrospective updates. As above, if it is recognised and accepted that the DTC flows provided will be based on a snapshot view of the SMRS data at the point in time that the DTC flows are generated then there should not be a problem. However, if further DTC flows need to be generated to update DC/DA/SVAA if SMRS is retrospectively updated then the requirements and timescales for this

Respondent	Response	Rationale
		need to be specified in the proposed solution. Requirement 5.4 does not state whether new or untraded MPANs should be included in any DTC flow. We assume not but, either way, this should be stated in the proposed solution. More significantly, requirement 5.4 requires us to use SMRS to exclude MPANS "*that may have voluntarily reduced load or been disconnected (e.g. due to a Demand Side Response agreement) during the Demand Disconnection event.*" This information is not held on SMRS and the requirement can therefore not be complied with. It will require significant changes to DSO and SMRS systems to allow such data to be recorded, updated to SMRS and utilised to exclude MPANS from the DTC flows. If required this will make a November 2015 change unachievable. Also, we assume that this requirement means we exclude any MPAN subject to voluntary reduced load during a Demand Disconnection event, even if the voluntary reduction only occurred for part of the Demand Disconnection period. If this is not correct then the requirement needs to be clarified.
ScottishPower	Yes	P305 will not significantly impact our systems or internal processes but will require a reconsideration and re-evaluation of the risks of more marginal imbalance pricing on our generation and supply businesses.
IMServ (Europe)	Yes	Given the lack of detail we can only respond in broad terms as to the likely areas of impact - • Change to HHDA Systems to enable sending/receiving of amended flows • Change to HHDC Systems to enable sending/receiving of amended flows • Change/Increase to Reporting, Estimations, data handling and data services and possible impact on Service Lines • Potential changes to NHHDC system • Depending on how the NNH change is implemented, there may be less impact in our role as NHHDA as our software solution is centrally co-ordinated therefore the implementation project is of a reduced scope and scale. This isexplained under Question 16.
TMA Data	Yes	The Demand disconnection event part of P305 would

Respondent	Response	Rationale
Management Ltd		affect our systems and procedures.
Drax Power Limited	Yes	There will be indirect impacts on our internal trading and risk processes if P305 is approved. Trading incentives will be altered due to the introduction of a single cash-out price and more marginal cash-out prices.
GDF SUEZ UK-Turkey	Yes	A move to a single imbalance price will: • Necessitate the amendment of processes and reporting that rely on the data flows affected by the changes • Necessitate a change to customer documentation as the industry definition of imbalance price will change GDF SUEZ would require a minimum of 6 months lead time to makes these changes to processes and documentation.
RWE Supply and Trading GmbH	Yes	P305 will improve the incentives to balance and improve overall market efficiency.
SmartestEnergy	Yes	We anticipate imbalance costs to increase. *Additional confidential information provided*
Flow Energy	Yes	The reduction in PAR will impact all suppliers, potentially exposing them to higher imbalance chargers and greater imbalance risks. This impact is particularly acute in the non-half hourly independent sector. As NHH suppliers tend to trade against a shape rather than in individual half hours, there is less scope for trimming positions in any given half hour to mitigate short notice imbalance or price events.
InterGen UK Ltd.	Yes	Changes to PAR will impact all generators, independent and vertically integrated. InterGen, as an independent generator, relies on the market providing cost reflective signals in order to keep current plant open and to invest in new capacity. The implementation of EBSCR will reduce the dampening of cashout prices and should help to incentivise adequate volumes of flexibility onto the system – essential in a market with increasing amounts of 'must-run' and intermittent generation. InterGen believes that sharpening cashout prices is absolutely necessary. The system cannot function without adequate flexibility. P305 will require InterGen to load follow more carefully, to balance our position with greater precision and reduce our imbalance costs. This will be to InterGen's benefit and to the benefit of

Respondent	Response	Rationale
		our customers. It will impact our organisation, ultimately in a positive way.
National Grid	Yes	There will be several direct impacts of P305 on National Grid in order to deliver the requirements to facilitate implementation of pricing Demand Control actions and Reserve Scarcity Pricing. These requirements relate to conducting analysis (for the purposes of constructing the LoLP), and the submission of new data and information. These impacts are detailed in the Transmission Company Analysis response we submitted to the P305 Impact Assessment. In addition to these, since market participants' behaviour is likely to adapt in response to the change in imbalance price incentives, there may be changes to the balancing actions we are required to take in our role as System Operator.
DONG Energy	Yes	DONG Energy is likely to face a significantly increased level of balancing cost, being the average increase in SBP as identified from the EBSCR forward modelling results. DONG Energy will also become structurally exposed to the risk of SBP price spikes, which is of particular concern given the inherent variable nature of our generation portfolio. DONG Energy notes therefore that we will not be running at an 'average imbalanced position', unlike other more predictable and/or baseload forms of generation who may be able to manage this more effectively.
Good Energy	Yes	As a small renewable supplier some expected benefits of potentially lower imbalance charges from moving to single cash out prices are likely to be offset significantly by a lower PAR value - and more so the lower the PAR. Any net benefit from these changes could be dwarfed by the effect of extreme events occurring eg the wind does not blow as expected at times of low system margin and our imbalance is penalised by very severe cash out prices due to the effect of high LoLP in conjunction with VoLL. This is essentially an unmanageable risk which will add to the overall supply costs for the business. We will also incur additional costs as set out in response to Question 6 below.
Centrica	Yes	Centrica would be impacted across our generation, supply and trading businesses. We consider that this change is likely to result in significant behavioural changes within the market, the

Respondent	Response	Rationale
		risks and therefore costs of imbalance will increase and therefore we will need to review and change our current policies to ensure they remain robust for the future. This will include a re-assessment and update of our imbalance volume forecasting model, hedging policy and processes for forecasting the System Net Imbalance Volume (NIV) and cash-out prices. It is likely that current contacts may need to be re-opened and re-negotiated as a direct result of this modification. Additionally, we are very concerned over the impact this modification may have on intraday liquidity due to the lack of differential between the SSP and SBP under a single cash-out price. This may result in a large reduction in intraday liquidity with many players forced to finalise positions day ahead.
RenewableUK	No	-
Electricity North West	Yes	We stated in the previous consultation that we will need to produce scripts to run against a number of IT systems to provide the level of reports required. We would then need to produce individual reports for each Data Aggregator and send the report to them as well as sending the full report to the SVAA. It now seems that the Working Group have introduced Dataflows without any business justification or cost benefit analysis being available. From our perspective, the probability of an event occurring is low so it seems a very expensive solution for what should be a straightforward reporting process.
VPI Immingham	Yes	As an electricity generator, P305 will change the monies that we pay / are paid. To facilitate this change, some minor modifications to our despatch models can be expected to reflect the new arrangements accurately. These modifications would be the same, regardless of the solution implemented. We would note that as an independent generator without a portfolio, should we have an unexpected outage, then we would be exposed to these high imbalance prices. However, we believe that this is the right approach as it encourages all parties to trade and cover their positions.
UK Power Reserve Ltd	Yes	Minor implementation impact, from a process viewpoint there will be some negligible changes required in our systems and documentation to allow

Respondent	Response	Rationale
		for the changes brought in by P305. These pose ourselves minimal risk/cost to business operations.
Green Frog Power	Yes	All changes to cash-out arrangements are likely to impact systems for data flows, contract terms, etc. The underlying goal of changes to PAR is not in dispute and that there is broadly agreement that the PAR volumes should be greatly reduced from the current levels and to go to single pricing. Therefore, we believe there are no material risks that outweigh the benefits, from a systems or costs perspective, of reducing PAR at once.
Vattenfall	Yes	*Confidential information provided*
Eggborough Power	Yes	All changes to cash-out arrangements will have some impact on parties. However, the implementation timetable should allow for system changes.
Haven Power Limited	Yes	There will be indirect impacts on our internal trading and risk processes if P305 is approved. Trading incentives will be altered due to the introduction of a single cash-out price and more marginal cash-out prices. The risk of a £3000/MWh imbalance charge would have to be considered as a single event and could have a very significant effect on a year's profitability. It is likely that we would have to increase our credit limit.
SSE plc	Yes	Trading and back office systems and processes will need to alter data capture routines to manage new and changed data items; and assess new parameters and data when optimising the portfolio and verifying settlement charges. Risk systems and processes will need to adapt fully evaluate potential price scenarios under a single marginal cash-out regime. More complex, structured commercial contracts that reference outturn imbalance prices will need to be amended to manage the altered price structure from dual to single cash-out. Supply Agency services will need to be adapted to cater for calculation and adjustment of Supplier volumes in the event of a qualifying Demand Control occurring. LDSO systems and processes already establish a link to MPAN within outage systems, but will need to alter

Respondent	Response	Rationale
		to identify IDNO area MPANs as well as notify the relevant DAs of the list of affected MPANs via the agreed communication media.
First Utility Limited	Yes	This modification will require an internal project to be run to deal with mitigating the adverse risk resulting from this modification. We will have to engage with a number of candidate trading parties and work with them to specify and develop products that will enable us to forecast and trade closer to gate closure. We have concerns that these products may not materialise, as there is no parallel industry change to require generators to offer such bespoke products to participants who may require them. In fact we believe there is a serious risk that the availability of such products will further reduce, with specific adverse impacts on independent suppliers which will undermine the recent progress on competition in supply. We note that domestic suppliers would be most impacted as the delivery profile of domestic electricity is 'peakier' than other users so that such suppliers would have greater exposure to the sharper cashout in the peak demand periods where cashout is already more expensive. We would need to factor in to our hedging policies a number of situations, including where products are not available, and work through the means by which this, and other risks, can be mitigated or at least recognised and accounted for. This would require a review of our policies and in light of that, considering other policies and processes based on or for which they are relevant, including around pricing and tariff development.
E.ON	Yes	We hope that the actual technical changes necessary to implement P305 should not be particularly costly, although various pieces of work will be required. While moving to a Single price would remove the risk of incurring costs from offsetting imbalances, we would potentially incur higher costs from sharper imbalance prices if P305 was implemented owing to the combination with decreasing PAR, RSP and VoLL, the more penal the smaller PAR volume is used. Our supply and trading businesses already invest heavily in demand forecasting with the aim of balancing our position and this is unlikely to change as a result of P305. (A more penal cashout regime simply provides an increased incentive to err towards going long). Strategic/behavioural/process changes to address the

Respondent	Response	Rationale
		increased risk that higher and more volatile imbalance costs would bring will take more time to implement. We would have to review our risk exposure, trading and hedging strategies for operating in a world with more volatile cashout prices, particularly the risk of incurring very high charges if we happened to be short in certain periods in a tight market if RSP and VoLL were incorporated at the VoLL levels suggested. Ultimately, increased costs, e.g. to our conventional generation business, if a plant trips, the Climate & Renewables business, if the wind fails to blow, and the Supply business, if customer demand differs notably from forecast, could all result in spikes in cost which cannot be predicted. Such increased risks and cost for the businesses and the work required to mitigate them would increase costs to end users. We note that the party-level historic analysis highlighted that a significant proportion of the negative impact on some parties could be owing to rcrc, i.e. not their own actions but other parties'. The analysis may not account for behaviour change but as previously noted we are doubtful that behaviours/decisions would/could change to any great extent as a result of P305. Consequently customers might be impacted by changes to our bottom line that are essentially beyond our control.
Stark Software International Ltd	Yes	Yes. New flows and procedures are required requiring a significant amount or work and testing. There will be ongoing impacts operationally, with further consequences on DTN volumes and Audit.
Utilita	Yes	As set out above, Utilita expects that P305 would significantly increase imbalance prices as well as decreasing their predictability. We do not believe that smaller suppliers would be able to mitigate these impacts – as set out above, due to the price signal not being available until after the event, the inability to influence NHH demand or hedge any more fully than is currently the case. We would expect that this will lead to Utilita (and other smaller suppliers) facing significantly increased imbalance costs which will have financial impacts both in terms of managing these costs and the associated credit requirements. This will lead to additional administrative costs. Based on our current analysis, we do not anticipate that the proposal would have significant system implications. The issues would be in costs to the business rather than system changes.

Respondent	Response	Rationale
Cornwall Energy	Yes	Industry participants will face the costs of changing systems and processes to adapt to a new world of marginal prices, single cash-out prices and the unpredictable factors of the Reserve Scarcity Pricing function and VoLL pricing. Parties could also be facing the increased cost of higher credit requirements.
EDF Energy	Yes	Our Retail divisions may need to adjust their risk and pricing assumptions to take into account the effect of the changes to cashout pricing, and the consequent changes to balancing risk premiums. We will need to modify our IT systems to receive the new proposed data flows. We will need to make changes to our trading processes, procedures, training, and decision support systems to take into account the new cashout arrangements.
Co-Operative Energy	Yes	Yes, implementation of P305 will require a thorough reassessment of our hedging policy and the processes around this. Discussions will also need to be held with our trading counterparties around credit requirements as these will be increased by the heightened imbalance risk which implementation will result in. It is also likely that implementation will result in an increased requirement for BSC balancing credit provision and this will have a disproportionate cash flow impact for smaller participants thus further negatively affecting competition.

Question 6: Will your organisation incur any costs in implementing P305?

Summary

Yes	No	Neutral/No Comment	Other
25	5	0	0

Responses

Respondent	Response	Rationale
Western Power Distribution	Yes	Unfortunately the requirements on DSO parties have not been fully developed yet. Based on the current assessment document and our assumptions as to exact requirements our estimate of costs are £20,000-£50,000 to implement with marginal ongoing costs.
ScottishPower	No	As for Question 5, P305 will not significantly impact our systems or internal processes but will require a re-consideration and re-evaluation of the risks of more marginal imbalance pricing on our generation and supply businesses. The cost impact of any increased risk may, ultimately, have to be passed on to consumers.
IMServ (Europe)	Yes	Following on from response to Question 6, potential costs can only be considered in broad terms until a greater understanding of the impact of this change can be established. One off costs: • Development, testing and deployment of System Changes documented in Question 1 for HH changes and testing and deployment of changes for NHH. On-Going Costs: • Additional data storage and processing capability • Additional Training, production of associated Procedures/LWIs, reporting, support, , general resources etc. • Additional Auditing/Performance Assurance support • Possible requirement for additional personnel dependent on volume

Respondent	Response	Rationale
		• Additional DTN costs BSC Systems Release: • There would be no difference in costs whether this was implemented as part or outside of a normal BSC Systems Release
TMA Data Management Ltd	Yes	The cost of implementing P305 would be medium to high for one off development and testing costs and low for on-going operational costs.
Drax Power Limited	Yes	Drax will incur some costs indirectly as a consequence of implementing P305. These costs will reflect the impacts on the organisation as detailed in the answer to question 5. However, it is difficult to quantify these costs at this time.
GDF SUEZ UK-Turkey	Yes	The costs relating to the above activities are: Necessitate the amendment of processes and reporting that rely on the data flows affected by the changes: • low Cost impact. Necessitate a change to customer documentation as the industry definition of imbalance price will change: • medium Cost impact. This will require input across a number of departments including Legal and there will be costs involved in sending customers revised documentation. It would make no difference whether P305 is implemented inside or outside of a normal BSC systems release, provided that there is at least a 6 month lead time.
RWE Supply and Trading GmbH	Yes	There will be some development (systems) costs associated with the implementation of the LOLP methodology and the introduction of the demand control arrangements.
SmartestEnergy	No	Operationally no, since both the SBP and SSP will be retained, but set equal to each other, so there should be no system impacts. Other variables such as LoLP, VoLL and PAR are not brought into our system.
Flow Energy	Yes	P305 is likely to increase imbalance costs, many of which it will not be possible for smaller, NHH, independent suppliers to mitigate. The costs are difficult to both quantify and mitigate.

Respondent	Response	Rationale
InterGen UK Ltd.	Yes	We anticipate there may be a minimal cost associated with changing our IT systems to reflect the reduction in PAR.
National Grid	Yes	Until the detail of the full P305 solution is confirmed (in particular the complexity of requirements to deliver the LoLP), we are not able to provide a firm indication of the costs to National Grid of implementing P305. In our Transmission Company Analysis response, based on our experience of a previous comparable project (European Transparency Regulation (ETR)), we estimated £1 million - £3.5millon. Given that our current view of the solution potentially requires less complexity than this previous project we would anticipate the cost of implementation to be on the lower side of this range.
DONG Energy	Yes	A full cost assessment can only be done when the modification has been implemented, however, it can be expected that we will incur higher transaction costs as a function of increased balancing and/or hedging actions taken, as well as the increased imbalance charges themselves.
Good Energy	Yes	We would incur additional costs in taking remedial action to attempt to mitigate the risk of sharper imbalance prices, and in making changes to operational elements such as updated systems and processes. There may also be further costs in meeting increased credit requirements stemming from more volatile cash out prices. Specific examples of costs related to systems and processes are the need to amend the importing, processing and reporting of data flows that will be affected by the changes. Any new data flows required will also add additional cost to set up - and ongoing because they are not currently imported, processed or reported on. There will also be the multiple one off costs to update generator PPA's and customer Power Supply Agreements to mitigate imbalance and credit risks. Note that the more contracts in place the higher the relative cost on the supplier in question. A ballpark estimate of the one off costs involved to Good Energy, excluding the impact related to expected changes to imbalance costs, is between £25k and £150k.

Respondent	Response	Rationale
Centrica	Yes	• In order to manage the increased risk of very high imbalance costs from P305, we will need to improve for forecasting modelling, this would involve system improvements and additional data requirements, we estimate this to cost around £100k in upfront costs and £100k per year for additional FTE to manage this risk, • The contract re-opening will require contract management and legal input, this could result in considerable expense, depending on the number of re-opened contracts. • The amount of credit required to be posted will increase considerably under P305, this will impact all market participants. • With the introduction of a single cash-out price and the corresponding reduction to intraday liquidity, we believe this will result in increased imbalance costs as parties will be less able to contract imbalances positions intraday.
RenewableUK	No	-
Electricity North West	Yes	The costs identified infer that the Distributor costs will be circa. £20k. This wouldn't have included the development, implementation and processing of new Dataflows, which seems to have been added as part of the solution since the first consultation was completed. This will introduce a significant increased cost of IT integration in order to produce the relevant data within the Dataflow, with no cost benefit analysis to justify such a requirement. We believe that until the 'top down' approach has been investigated further and compared against the suggested 'bottom up' approach it would be difficult for the solution to be given further consideration.
VPI Immingham	No	With the exception of different cash out costs, the only cost incurred will be the small amount of time required to update any corresponding analysis to reflect the revised approach. This is expected to be negligible.
UK Power Reserve Ltd	No	No, our systems our sufficiently robust that there will be no significant cost implication for the revisions required.
Green Frog Power	Yes (minor)	There will be costs for our organisation but it will also encourage us, first to build new peaking plant, exactly what the market requires, and second to be able to tender in lower prices to the Capacity Market

Respondent	Response	Rationale
		auction.
Vattenfall	Yes	The trading arm of Vattenfall will incur one off costs for development, implementation, testing and training for the changes to the booking and scheduling processes In addition to this, the trading arm of Vattenfall will incur ongoing costs of higher imbalance costs, and resulting higher credit requirements. In addition to this, the generation business will incur ongoing increase in the cost of PPAs. This will be reflective of the increase of imbalance costs. This impact is further discussed in question 14
Eggborough Power	Yes	We will face some cost in altering contracts and IT systems. We believe the benefits will outweigh these costs.
Haven Power Limited	Yes	There will be some indirect costs of implementing P305. These costs will reflect the impacts on the organisation as detailed in the answer to question 5. However, it is difficult to quantify these costs at this time.
SSE plc	Yes	The vast majority of costs are one-off costs to amend systems and processes to adapt to the new methods of formulating price and volume and verifying imbalance charges; and identifying and handling the list of disconnected MPANs and associated volume estimates in the event of an involuntary demand disconnection. Ongoing costs will be minimal. Set up costs for Wholesale business should be low to medium cost (10k – 100k). Set up costs for Distribution business should be low to medium cost (10k - £100k). Set up costs for NHHDA will depend upon the cost of change to Elexon centrally distributed software. Additional SSE cost beyond central software change will be in the region of £10k - £15k. There is an additional project management overhead associated with implementing change outside of a scheduled BSC System Release; however it would not be of great concern if an ad-hoc release were required as our preference is to work towards a Winter 2015 implementation.
First Utility Limited	Yes	Minimum costs implementing, significant cost

Respondent	Response	Rationale
		mitigating, where possible, and accounting and reporting, based on the reasons described in our previous answers.
E.ON	Yes	Implementation in a normal BSC Systems Release is always preferable in that some time and budget is already allowed for IT at least to implement these regular releases. Outside a normal release inevitably incurs additional costs and more lead-time to seek approval, which can take up to three months before work can even begin. With P305 implementation specifically, some one-off up-front costs will be incurred to make changes to our processes, IT systems and interactions, for instance to receive additional BMRA messages/forecast de-rated margin/indicative/final LOLP values etc. for each half-hour. We do not anticipate that these costs should be excessive, though more work is required to determine exactly how forecast/indicative figures might be used, and the extent of the corresponding increase in IT, process and workload changes. It is harder to ascertain how we might be impacted by rarer events such as the adjustment of Suppliers' settled nhh volumes following any Demand Control actions. As we already invest significantly in demand forecasting and do not believe that any particular improvements could be made to forecasting demand or plant availability (wind forecasting now being possible with a good degree of accuracy (~80-85% by gate closure), we would not seek to improve forecasting capabilities for P305, so do not anticipate costs/lead time for this. (On the contrary, the prospect of occasionally incurring extremely high costs due to e.g. an unforeseen plant breakdown, potentially negating the benefit of generally being a 'better balancer', could undermine the case for any further investment). Ongoing costs incurred by P305 may well include increased credit requirements; it is difficult at this stage to estimate the potential ongoing cost/risk premium required for this as well as the wider work attempting to manage the increased risks from sharper and more volatile cashout prices. The smaller the PAR volume the greater these risks and costs would be; ultimately these would inevitably feed through to consumer bills.
Stark Software	Yes	Yes. Teens of thousands for implementation. No

Respondent	Response	Rationale
International Ltd		difference expected as a result of timing. Further operational costs depending on volumes and the level of queries resulting.
Utilita	Yes	As above, we do not expect significant system changes, but we do expect changes to the costs the business would face in terms of the impact of the higher, more volatile and less predictable imbalance prices in conjunction with the increased credit cover requirements and administrative costs. We expect these costs would increase more, the greater the change which had been made to PAR. If the alternative suggested above were considered to introduce a single imbalance price and omit a change to PAR, we believe that these anticipated business costs would be significantly reduced. We would still expect some costs of internal process change, but these would be lower.
Cornwall Energy	Yes	The implementation of P305 could have notable effects on the industry. Changing the level of PAR to 50MWh and 1MWh are significant changes and could increase the cost of trading and effect the risk appetite for trading parties, increasing the cost of purchasing wholesale power, especially for smaller suppliers. For smaller low-carbon generators the increase in PAR is likely to raise the imbalance discounts required by offtakers, reducing the returns available and increasing the cost of renewables. With an increase in PAR and imbalance prices the level of credit to be posted will increase. This has a direct impact on participants, especially those not able to easily access sources of collateral. These factors will have a knock-on effect on the tariffs offered by suppliers, the price of wholesale power in the energy market and the strike prices cleared under the Contract for Difference Feed-in-Tariffs. Moving to a single imbalance prices will change the risks associated with trading and being in imbalance, either short or long depending on the view of the system imbalance, parties may need to revaluate their trading strategies as a result of this.
EDF Energy	Yes	The IT change as a result of this modification is likely to cost in the region of £200k. In addition, we anticipate spending approximately

Respondent	Response	Rationale
		0.75 man-year-equivalent on non-IT change when making the necessary changes to our business. *Additional confidential information provided*
Co-Operative Energy	Yes	Yes, it is likely that the reduction of PAR to the extent proposed will result in heightened credit requirements to market participants for both balancing and bilateral trading purposes as the risk created by potentially much higher cash-out prices will need to be factored in. In the case of non-vertically integrated participants with regard to bilateral trading purposes these additional credit requirements are likely to take the form of cash or a letter of credit, thus tying up working capital which cannot then be invested in growing the business. This will impact the ability of smaller non-vertically integrated participants to effectively compete with the larger vertically integrated participants on a level playing field.

Question 7: Please provide your views on what PAR value(s) should be proposed and whether you believe a phased approach should be adopted.

Responses

Respondent	Response
Western Power Distribution	We do not have a view on this.
ScottishPower	If Parties are unable to respond rationally and reflect changes in cash-out price in their economic decisions then the change will not deliver increased efficiency in the market arrangements. By staging the reduction in PAR and holding it at 50MWh Parties would have time to respond to the change by adjusting their contracting their hedging strategies and reflecting the increased value of flexibility in both their balancing services and consumer product costs. A post-change review should be carried out to determine whether the benefits from a move to PAR = 50MWh have been delivered following which any Party would be able to raise a Modification for a further reduction for example to PAR = 1MWh.
IMServ (Europe)	No view
TMA Data Management Ltd	We believe that going straight to a PAR value of 1MWH should be adopted. As discussed by the Modification group, if a PAR of 1MWH is beneficial to the industry, that benefit should be realised as soon as possible. This is further demonstrated by the fact that a PAR of 1MWH would include an average of 3 to 4 actions as opposed to 6 for 50 MWH.
Drax Power Limited	We believe a more cautious approach should be adopted in lowering the PAR value. We do not believe that the PAR value should be lowered to 1 MWh as we are concerned about the impact of system pollution. We consider a PAR value in the range 50 MWh – 100 MWh to be appropriate if Ofgem wishes to strengthen cash-out price signals. A PAR value in this range would also reduce the potential for system pollution. If a value in this range is adopted, we do not consider a phased approach to be necessary.
GDF SUEZ UK-Turkey	P304 (which was supposed to provide a 'glidepath' to more marginal cashout prices) has been rejected. A move straight to a PAR 50MWh will therefore be too much of a shock to BSC Parties. GDF SUEZ suggests a more moderated approach starting at PAR 100MWh. BSC Parties would then be free to raise a further modification to reduce the PAR value. Ofgem should make clear that they will not consider further reductions in the PAR value until P305 has been in place for at least a year and that PAR 1MWh will only be introduced after 1 November 2018 as set out in the modification.
RWE Supply and	The PAR values as set out in the original modification should be

Respondent	Response
Trading GmbH	implemented.
SmartestEnergy	Our preference is PAR100 (or higher) and fixed until such time as another modification is raised. We do not believe a phased approach should be used. However, we are not averse to P316 being used to reduce PAR further at a later date.
Flow Energy	As per P316, a graduated reduction of PAR to 250MWh and then to 100MWh after 12 months will help mitigate some of the shocks to the sector from potential higher imbalance charges and greater imbalance risks, this will help better facilitate competition in the sector as per BSC objective C. Other alternatives will expose suppliers to significant costs and changes too rapidly.
InterGen UK Ltd.	InterGen is supportive of ultimately introducing a single marginal cashout price with a PAR 1 value. We do, however, support the phased introduction of PAR 1, and suggest that PAR 50 be implemented ahead of Winter 2015. We have noted from industry responses to earlier EBSCR proposals that a phased approach to a PAR reduction is preferable to some participants who require more time to complete a full impact assessment and to trade out their position accordingly. InterGen believes that a reduction to PAR 50 at the start of Winter 2015 allows sufficient time for planning, analysis and requisite system changes.
National Grid	Aligning to the conclusions of the EBSCR Final Policy Decision, we support the proposed PAR values (of PAR50 on P305 implementation followed by a subsequent step to PAR1 for winter 18/19). As a solution, a phased approach to reducing PAR seems preferable to a single-step reduction since it allows both the System Operator (SO) and industry the opportunity to assess how market participant behaviour adapts in response to stronger price signals. Notwithstanding our support for the proposed solution (and the 50MWh PAR), of those potential alternative values offered in the consultation report, an initial PAR of 100MWh should strengthen signals sufficiently to incentivise changes to behaviour and should therefore form a reasonable alternative.
DONG Energy	As set out in the response to Question 1, DONG Energy is not convinced that a reduced PAR increases the efficiency of the electricity and balancing market. DONG Energy believes the current balancing mechanism framework already provides sufficient incentives to facilitate an efficient functioning of the market. However, in the case that a PAR reduction is implemented a staggered, slower digression should be adopted to give market participants the chance to adapt to the changed environment and to create strategies to mitigate at least part of the risk resulting from higher imbalance prices.
Good Energy	We propose a reduction in PAR to 250MWh upon implementation and then to 100MWh 12 months later, one of the options being

Respondent	Response
	considered by the Workgroup. The historic analysis undertaken by Elexon shows that there appears to be a more significant increase in cash out prices from PAR reducing from 250 to 100MWh than for any of the other step changes in PAR under consideration by the Workgroup, thus achieving much of the required benefits of sharpening of prices. However, with PAR at 100MWh the concerns we have with possible distortions to cash out prices due to erroneous flagging and tagging of balancing actions are significantly diluted. With PAR currently at 500MWh we would prefer an initial reduction to 250MWh so that we are able to gradually gain experience of the more challenging market and give us more time to seek to mitigate the associated risks.
Centrica	We suggest a prudent initial reduction should be in the region of 100 – 200 MWh. This will ensure that a sharper cash-out price will be implemented whilst minimising any potential unintended consequences or market shocks. If, following a period of time for analysis and review, further reductions to the value of PAR are considered necessary; this can be achieved via the raising of further modifications. If a double reduction is considered appropriate under this modification we would support a reduction to 200 MWH from 5th November 2015 and a further reduction to 100MWh from winter 2018.
RenewableUK	RenewableUK's position has consistently been that moves to reduce PAR should be implemented in a phased manner, giving market participants adequate opportunity to adjust to the new situation. With PAR at 500, variable renewable generators already receive appropriate incentives to improve forecasting in order to minimise exposure to imbalance charges, given the relatively limited scope to do better. If incentives are to be sharpened, new approaches will be needed to limit the impact, and these will need more time to implement. Of the options set out in the consultation document, RenewableUK would prefer the one which has an initial move to PAR250 followed by a further move to PAR100 12 months later. At that point a review would be appropriate to decide if a further step to PAR1 is justified. However, as set out in our response to Question 1, we believe other options with smaller initial steps should be investigated, and also that reviews to ensure that objectives are being met and particular classes of generator not overly disadvantaged be undertaken before later steps down are taken.
Electricity North West	Not applicable to Distributors.
VPI Immingham	In our opinion, PAR should be adapted to 1MWh as soon as possible

Respondent	Response
	to truly reflect the marginal price of balancing the system. This would also resolve any issues arising from the interaction between P305 and P316. Given the timeframes and notice given, we believe that this gives adequate time for participants to prepare for the modification without a phased approach being required. We do not believe that a higher PAR value, e.g. 250MWh, would have any significant impact on behaviour due to the small nature of the change and therefore would not support an alternative modification of this amount. Currently, the true cost of balancing the system is not reflected in cash out and a small change in PAR would continue this trend and would undermine the intention of the Electricity Balancing Significant Code Review.
UK Power Reserve Ltd	UK Power Reserve believes that a PAR value of 1 should be achieved as rapidly as possible alongside the introduction of single pricing, a phased approach would delay the best solution being implemented. We also believe that a delayed or phased approach would not benefit either parties or end consumers in providing time for adaption as the market conditions and behavioural reactions of each PAR level would be sufficiently unique to make them irrelevant for the desired end condition of PAR 1. Our concern is that a phased reduction of PAR does not provide the signals required to the market for encouraging behavioural change and encouraging investment and that is does not best meet the BSC objectives to delay the reduction of PAR to 1. It would also pose contractual issues in that agreements would likely cover periods of multiple PAR levels whereas a timelier drop to PAR 1 would permit a single changeover point.
Green Frog Power	We would like to see PAR set to 1MWh in November 2015. We can understand the concerns over more marginal prices, as this seems like a dramatic change, but with a simple, single-price system, we believe, as supported by Elexon's analysis, that the market can and will respond, to the benefit of improved market liquidity and a more efficient system. As noted above, Elexon's analysis indicates that the impact of reducing PAR volumes is non-linear and therefore a small reduction is not necessarily indicative of what the results of a larger change might be. In addition, Elexon's analysis indicates that the move to a single cash-out price offsets potentially worrisome consequences (for small players particularly). If a decision is made to reduce PAR volumes in an incremental way, yet move to a single price immediately, then the baseline for analysis of further PAR reductions will be biased. We believe there is a strong risk that the final PAR volume reduction may not then occur – jeopardising the integrity of the market and the potential benefits of cash out reform.
Vattenfall	Vattenfall supports the proposal of a move to 250MWh on implementation, moving to 100MWh 12 months later. Any further reductions in PAR we believe should be after further analysis, and in

Respondent	Response
	consultation with industry. This will enable parties to assess the impact of the prior reductions in PAR on their business, and perhaps adapt their position outlined in prior consultations.
Eggborough Power	We consider that PAR should be set to 50 MWh at the time of implementation with a commitment to move to 1 MWh in November 2016. We have some concerns that more marginal prices may create some price spikes. A larger PAR may remove a few very spiky prices that are not representative of system stress as a whole. For P305 there seems to be a good case for moving to more marginal prices as a first step towards implementing Ofgem's package. These may also provide a way to allow for further development around the more complex elements.
Haven Power Limited	We believe a more cautious approach should be adopted in lowering the PAR value. We do not believe that the PAR value should be lowered to 1 MWh as we are concerned about the impact of system pollution. We consider a PAR value of 50 MWh to be appropriate to strengthen cash-out price signals. This PAR value would also reduce the potential for system pollution. If a PAR value of 50 is adopted we do not consider a phased approach to be necessary.
SSE plc	SSE would prefer a fully marginal PAR value at the earliest opportunity, but are comfortable that the proposed PAR value of 50MWh between 2015 and 2018 allows a more gradual introduction to allow market players to adapt their understanding and responses to an increasingly sharp cash-out signal; and will also sufficiently drive the intended changes in behaviour desired and anticipated. We do not believe that any further phasing of PAR values is required beyond those proposed. We do not believe that any PAR value above 100MWh is warranted as an alternative, as the combination of a higher volume weighting of the price stack and a single price (with the associated removal of exposure to the cost of the system price spread), will continue to dampen price signals and neutralise/undermine the intent of the proposal.
First Utility Limited	We are concerned that because no data analysis has been performed across a relevant period of scarcity, it is hard to anticipate all potential consequences and more likely to manifest unintended consequences. These could adversely affect participants in the balancing mechanism. If the unintended consequences are severe (and we have no way to know how severe they could be without a full analysis that includes periods of scarcity and which also incorporates some modelling of the likely bidding behavioural changes in cashout this modification would introduce), then it is unlikely there would be time to change the industry quickly enough to stop exposed parties from being exposed to significant financial difficulty. We therefore recommend a gradual reduction in PAR starting with PAR 250 and single cashout in November 2015.

Respondent	Response
	Ofgem has suggested that such a reduction will lead to new products entering the market to allow parties to improve their balancing position. As discussed in our previous answers, we believe there is sufficient basis to infer that the opposite may be the case as a direct result of the high levels of vertical integration in the industry. We suggest that Ofgem monitors closely with independent suppliers, and other participants, from the current time and continuously during the 12 month period from November 2015 to ensure these products do indeed become available and to assist all participants in fully understanding the changes to market behaviour.
E.ON	We do not believe there is any evidence that reducing PAR would actually improve balancing efficiency given the limited scope to do better; parties are already incentivised to balance and attempt to do so to the best of their ability. A smaller PAR would not suddenly enable parties to become better balancers: forecasting and plant will never be 100% reliable and further investment, even if there is a budget for such, will not necessarily result in considerable improvements. Increased costs owing to P305 might anyway mean that parties are less able to invest in any improvements to systems. Phasing in any reduction would be sensible in order to give parties some lead time to prepare for the change and adjust behaviour if applicable and time, cost and product availability allows. A period of some stability is also desirable following any change to allow parties to evaluate the new regime; it would also allow the regulator to monitor the impact on the market before any second phase was instigated.
Stark Software International Ltd	No Response
Utilita	We do not believe that PAR should be reduced at this point. We believe that it would be appropriate to introduce an alternative to P305 which would move to a single imbalance price and not change PAR. The impact of this change (in conjunction with wider change such as EMR) should be monitored before further change is considered. If a change to PAR is considered, we would recommend a modest change to 350MWh and as before the impact to be observed before further implementation is considered. We therefore agree that any changes to PAR should be phased.
Cornwall Energy	Our preferred PAR option is 250MWh, and we believe a phased approach to any further reductions in the PAR value should be adopted. Ideally there should be an industry process to ensure further reductions in PAR are having the desired effect and not causing any negative impacts in the energy markets. Increasing the marginality of PAR will reduce its effectiveness as a measure of the marginal action taken to balance the system across the half hour. Taking the most expensive action could pollute the

Respondent	Response
	calculation of the marginal price as it does not take into account the duration (beyond the CADL) of the action, we therefore prefer as large a PAR value as possible so that it truly reflects the marginal cost of balancing the system.
EDF Energy	Small Price Average Reference Volume (PAR) values such as 50 MWh or 1 MWh could significantly increase the volatility of imbalance prices, due to the granularity of offered balancing action prices at the margin in some circumstances. Without a cleared price for balancing actions, and without an administered scarcity price floor in each period, participants must estimate the value of balancing actions, and the likely interaction of price with dynamic parameters of demand and generation, when submitting prices. Small values of PAR increase the risk of price manipulation if any concentration of market power in balancing were to occur. Artificial volatility and price manipulation would have a negative effect on competition in the purchase and sale of electricity, counter to BSC Objective C. Increasing the average number of actions which set the market price would help to dilute market power. We note that the Authority believes that an average of three or four actions would set the price under a 1 MWh PAR value, indicating expectation of a large number of bids or offers (as appropriate) clustered together at the same or similar prices. When National Grid dispatch units which were originally planned to not run, to deal with a significantly short system, PAR 1 would almost inevitably result in acceptances from a single bid-offer pair from those units – which typically have a SEL of more than 100 MW – setting the imbalance price. Very small PAR values would also exacerbate anomalies between the real-world features of physical balancing compared with the arbitrary half-hourly resolution of trading and imbalance measurement. Real balancing requires consideration of dynamic behaviour of generators and demand and network constraints, within half-hours and spanning half-hours. The price of balancing actions affecting only part of a half-hour, or actions spilling over from other half-hours, or due to network or other system constraints, may bear no correlation with the real-time imbalance of a particular participant. Exposure of individual participants to imbalance prices which are not reflective of the costs they cause is unlikely to be efficient. Use of a larger PAR value dilutes the effect of such anomalies over the half-hourly resolution of trading and imbalance measurement. We believe that a PAR value of **100 MWh** would result in increased (but not extreme) volatility, and would reduce scope for anomalies due to interactions between real-life real-time balancing and half-hourly measurement, trading and imbalance, and also reduce any potential for price manipulation by individual participants. If further change to PAR were warranted in the future, this could be done

Respondent	Response
	through a relatively simple BSC modification. We do not believe that PAR values should be subject to an automatic change at some point in the future. We believe that it is impossible to accurately model the effect that the proposed changes to the cashout arrangements would have on market participants, and we would look for empirical evidence on the effects of these changes before supporting further change. Given that a BSC Modification to change PAR could be raised and assessed relatively quickly, we feel it would be better for the Industry to take stock following implementation of this modification, and take an evidence-based decision on whether a further reduction was desirable.
Co-Operative Energy	We have listed our preference from the options under consideration in our answer to Question 2 above. However, our preferred solution is described in our answer to Question 3 along with our rationale for this. It is in our view essential that any reduction to PAR be delayed until the market has had a sufficient period of time to adjust to the prior introduction of single-priced cash-out. We would suggest the introduction of single-priced cash-out in November 2015 and any reduction to PAR not earlier than twelve months following this.

Question 8: Do you prefer the proposed 'dynamic' LoLP function or the alternative 'static' LoLP function?

Summary

Dynamic	Static	Neutral/No Comment	Other
5	15	10	0

Responses

Respondent	Response	Rationale
Western Power Distribution	-	We do not have a view on this.
ScottishPower	Static	Unless the calculation of LOLP produces a reliable signal of tightening system margin and potential demand reduction, Parties will be unable to respond rationally and trade efficiently to manage their positions. The Proposed "dynamic" function does not appear to deliver a predictable signal and could therefore lead to Parties trading inefficiently thus our preference is for the "static LOLP" function. We believe that the final LOLP value and the correlation to the de-rated margin should be published as soon as the data for the preceding season is available. Combined with the publishing of forecasts of de-rated margin on the BMRS, this would give Parties the opportunity to factor the impact of potential use of STOR on imbalance prices into their trading decisions.
IMServ (Europe)	-	No view
TMA Data Management Ltd	Dynamic	We agree with the majority of the workgroup that a static LoLP function would make it easier to trade against, however, imbalance prices are dynamic; this dynamic dimension should be incorporated into the Loss of Load Probability function to be meaningful.
Drax Power Limited	Static	We prefer the intent underpinning the 'static' approach i.e. to provide greater certainty to market participants of market signals allowing them to more efficiently react to these signals. The 'dynamic' approach is highly volatile and has produced counterintuitive results. In efforts to improve the model, National Grid has undertaken back calculations to 'fix' the results and facilitate the 'correct' answers. We have concerns that the fixes undertaken do not create a model fit for future use, but rather corrects the application of the model to

Respondent	Response	Rationale
		highly specific historical periods. As a result, we fear that the 'dynamic' method will fail to provide transparent signals to market participants to allow them to amend their behaviour. But that is not to say that the 'static' approach is fully developed either. The 'static' approach still requires further development to demonstrate that it can deliver a transparent signal of scarcity to market participants. In particular, the mathematical relationship between de-rated margins and LoLP has yet to be developed. Overall, both approaches will require further development and especially testing in real market conditions to determine the efficacy of the solution. Without this real world testing, market participants are unlikely to have confidence that the resulting cash-out prices produced in any way reflect market fundamentals e.g. scarcity. Given the potentially large financial impacts associated with the LoLP method, we believe that the model should not be implemented until it has been tested thoroughly, ideally for at least one year in a live environment.
GDF SUEZ UK-Turkey	Dynamic	Whilst the dynamic function is not known until gate closure, it does have the benefit that the LOLP are based on live plant data rather than plant availabilities in the previous year.
RWE Supply and Trading GmbH	Static	The static LOLP function may better reflect the supply demand fundamentals and provides a rationale market signal. Further work is required to understand the sensitivity of the dynamic LOLP calculation to the different circumstances that may prevail in the balancing mechanism (e.g. high wind output/low wind output). We also believe that all the data that is required to calculate the LOLP function must be available to market participants. This data should include the relevant MEL submissions, NG assumptions about availability in the balancing mechanism and the demand forecasts for each snapshot period. This is required to enable market participants to replicate the LOLP calculation and validate the NG model.
SmartestEnergy	Dynamic	We prefer the dynamic LoLP function. It is inevitable that the Loss of Load Probability will be constantly moving and it is the final one before gate closure

Respondent	Response	Rationale
		which should count as that is as close as possible to when STOR is likely to be called. Whilst forecastability would normally be desirable, the costs which are to be fed into the cash out calculation are, by their nature, reflective of last minute balancing actions.
Flow Energy	Static	A static LoLP will provide greater certainty and much less volatility, especially for smaller, independent suppliers who are less able to fine tune positions up to gate closure. This is especially true for independent domestic suppliers who don't tend to trade by the half-hour, instead taking predefined shapes. A dynamic, or short lead, LoLP function will expose the independent, domestic, sector to risks that it is not able to mitigate.
InterGen UK Ltd.	-	No comment at this time.
National Grid	-	We believe that the level of accuracy delivered by the proposed dynamic LoLP solution is greater than that of a static alternate. However, there may be advantages to applying a static model if it provides a solution that can be more readily understood by market participants and as such can be used as a meaningful signal to inform their balancing decisions on implementation. Whilst we perceive a gain in accuracy from the dynamic solution we do not necessarily consider this to be considerable enough to outweigh the benefits of a solution that parties have more confidence in as a market signal.
DONG Energy	-	DONG Energy believes there are benefits and disadvantages to both of these solutions but as there has not been an assessment of the static solution we see a requirement for further assessment of the impact of the static LoLP to decide for a preferred solution.
Good Energy	Static	Despite various changes to the 'dynamic' LoLP function during the course of its development, we are concerned the proposed LoLP function appears unpredictable, is not sufficiently transparent and is more a measure of short term plant availability than lack of capacity. The latter is illustrated in Graph 4 & 8 in Section 2 of the Detailed Assessment where LoLP is shown to rise generally between 2 hours & 1 hour ahead of real time, which we understand to be due to plant that has declared itself available subsequently failing to start. The 'static' LoLP function is inherently more robust and hence more predictable, being based on a predetermined

Respondent	Response	Rationale
		relationship between LoLP and system margin.
Centrica	Static	If a dynamic LoLP function could be developed and tested to provide accurate results in a robust and transparent manner providing market participants with a reliable signal to enable appropriate reactions to a stressed market this would be our preferred solution. However, we believe that there is insufficient time available under this modification, in order to finalise the development of an appropriate calculation of LoLP. Once developed the LoLP would need to be tested against a number of years of historical data to ensure that it provides consistent and stable results. Furthermore, information on the function would need to be published to ensure the transparency of the function is maximised. Although there has been some development in National Grid proposed dynamic function, we do not consider that it is sufficiently robust and transparent to provide the necessary signals to market participants. Accordingly, we support the adoption of a static LoLP function as we believe this is the most appropriate way forward at this time.
RenewableUK	-	No opinion
Electricity North West	-	Not applicable to Distributors.
VPI Immingham	Dynamic	We remain to be convinced that either of the proposed LoLP functions is robust enough to be implemented in its current format. In principle, we favour the dynamic LoLP, believing that it is a better reflection of actual market conditions at any given time ahead of gate closure, but remain concerned by the opacity of some of the calculations, making it difficult to replicate and hence model ourselves. On balance, we believe that the dynamic proposal better reflects the intention of the LoLP function, which is to sharpen market signals and hence incentivise market participants to balance their position ahead of gate closure. However, it is only when participants have enough notice and foresight to take corrective action that the function becomes useful. Whilst the static proposal goes some way to addressing these concerns, we do not believe that it is fit for purpose as we are unsure exactly how you would go about calculating the historical LoLPs and hence how you would derive the function. In addition, changes

Respondent	Response	Rationale
		year to year in terms of policy, generation mix, demand, etc could mean that the function is not meaningful for a subsequent season. This is especially true once the first capacity mechanism delivery year begins. We believe that the dynamic LoLP would better reflect the actual LoLP and is would therefore better deliver the intent of the EBSCR. However, we wish to see more robust analysis presented.
UK Power Reserve Ltd	Static	In the interest of simplicity a static LoLP function would be preferential.
Green Frog Power	Static	For P305, we believe that the static LOLP may be more robust.
Vattenfall	Dynamic	Vattenfall supports the dynamic LoLP function because of the increased accuracy of this method. Wind is particularly sensitive to changes in availability of plant over time. As the technology evolves, and the mix of offshore and onshore shifts – with offshore technology innovation and resulting changes in reliability being more pronounced – reference to historic data might result in inaccurate LoLP values. Moreover, Vattenfall believes that interconnectors should be considered within the LoLP calculation, again, to improve the accuracy of the LoLP value being used. Vattenfall also supports the proposal that the values are further split between day and night.
Eggborough Power	-	-
Haven Power Limited	Static	We do not feel that either method has under gone sufficient analysis to be confident in its implementation, particularly during a time period that corresponds to a tight system. We currently do not have enough information to be able to state a strong preference for either method. Ideally we would like to evaluate how both methodologies perform over this winter before making a decision. We are not convinced that RSP should be calculated using either of the LoLP functions. The 'dynamic' approach is highly volatile and has produced counterintuitive results. In efforts to improve the model, National Grid has undertaken back calculations to 'fix' the results and facilitate the

Respondent	Response	Rationale
		'correct' answers. We have concerns that the fixes undertaken do not create a model fit for future use, but rather corrects the application of the model to highly specific historical periods. As a result, we fear that the 'dynamic' method will fail to provide transparent signals to market participants to allow them to amend their behaviour. We prefer the intent underpinning the 'static' approach i.e. to provide greater certainty to market participants of market signals allowing them to more efficiently react to these signals. But that is not to say that the 'static' approach is fully developed either. The 'static' approach still requires further development to demonstrate that it can deliver a transparent signal of scarcity to market participants. Overall, both approaches will require further development and especially testing in real market conditions to determine the efficacy of the solution. Without this real world testing, market participants are unlikely to have confidence that the resulting cash-out prices produced in any way reflect market fundamentals e.g. scarcity. **Given the huge financial impacts that the LoLP calculations could potentially have on parties we feel that the model should not be used until it has been tested further, ideally for at least one year in a live environment.**
SSE plc	Static	Whilst recognising that the dynamic LoLP calculation is statistically robust, SSE are concerned that last minute changes in value may be producing a signal that gives false comfort and equally cannot be responded to if only visible at Gate Closure. This has the potential to weaken the intent of the proposal to sharpen signals at times of scarcity that will allows the market to respond rather than leave to the SO as residual balancer. SSE would prefer a static function derived from the model developed by National Grid, calculated and published in advance of Summer and Winter seasons, and complemented by the publication of de-rated margin data signals. This would better allow the market to assess the probability of STOR being utilised and LoLP becoming effective, and respond appropriately in the forward market to buy on flexibility to manage risk. Were a dynamic LoLP function pursued, then SSE

Respondent	Response	Rationale
		would prefer the final LoLP to be calculated at 4 hours ahead rather than Gate Closure.
First Utility Limited	Static	The dynamic LOLP solution creates additional unnecessary uncertainty for little gain and this uncertainty will be very difficult to manage. For this reason we support the static LoLP function.
E.ON	Static?	It is unclear what if any great benefit introducing either LOLP methodology could achieve. The static function might be preferable for simplicity. It seems from the analysis performed by National Grid while developing the methodology that even with a complex dynamic function (potentially more prone to errors), accuracy is going to be limited much beyond real time, and parties are unlikely to change behaviours based on early indicative LOLPs that might be misleading. On that basis it can be argued that excessive work could be avoided by utilising a static methodology. However being based on historic availability a static methodology risks being overly crude; while if they wished to use it parties would have more work nearer real time to consider the forecast de-rated margin and what LOLP they estimate that might mean before the actual value was confirmed. A dynamic function calculated by National Grid that should have greater accuracy might thus be preferable. However, if it is to be of any practical use in enabling parties to respond, calculation at Gate Closure as currently proposed for the dynamic function would be too late.
Stark Software International Ltd	-	No Response
Utilita	-	Not addressed in this submission
Cornwall Energy	Static	We prefer a static LoLP function calculated ahead of time and applied to another factor such as demand or de-rated system margin. The dynamic function is too complex and vulnerable to short-term signals such as plant trips. We therefore prefer a simpler approach which would be easier to trade and hedge against.
EDF Energy	Static	We acknowledge that the “dynamic” LOLP function may provide more accuracy in terms of modelling the probability of a loss of load. However, the function is both complex and opaque, relying on data that are available only to National Grid.

Respondent	Response	Rationale
		If this modification is to produce behavioural changes, it is important that factors such as the RSP be able to be modelled in advance, so as to provide parties with the appropriate incentives to trade or otherwise optimise their permissions. The "static" model, while being far from perfect in terms of complexity and transparency, will allow parties a greater opportunity to make accurate decisions about the economic despatch of plant, and to efficiently and economically trade out their positions.
Co-Operative Energy	Static	We prefer the alternative "static" LoLP function as this will allow more thorough risk assessment by market participants due to LoLP costs being delineated ahead of the relevant period.

Question 9: How far ahead of real time do you believe the Final LoLP value under the alternative 'static' LoLP function should be determined?

Responses

Respondent	Response
Western Power Distribution	We do not have a view on this.
ScottishPower	**Four hours ahead** There will be a trade-off between early certainty of the final LOLP and the accuracy of the de-rated margin. As the forecast de-rated margin will be published on the BMRS and updated at regular intervals, we believe that final LOLP should be set as close to Gate Closure as possible but still allow Parties the opportunity react. We would therefore support determination of the Final LOLP value four hours before the Settlement Period begins. This would align with reaction times within the Capacity Mechanism design.
IMServ (Europe)	No view
TMA Data Management Ltd	**Four hours ahead** Provided that 4 hours before gate closure would allow the inclusion of the Wind forecast and still provide some reaction time from participant to adjust their position, we favour the option to publish the Final LoLP value under the alternative "static" LoLP function 4 hours of Gate Closure.
Drax Power Limited	**At least two hours ahead** We consider that there is merit in setting the de-rated margin ahead of gate closure, at least two hours ahead of the Settlement Period (SP). The analysis to date has revealed sudden spikes in LoLPs between two hours ahead of the SP and Gate Closure. This is probably capturing last minute plant trips just before gate closure. We do not believe that the RSP Function should be seeking to send signals related to sudden last minute plant trips or that these events should be reflected in cash-out prices. Such events are unlikely to reflect the underlying degree of scarcity on the system. Additionally, at Gate Closure it is not possible for a market participant to react to this increased LoLP signal and effectively mitigate the impact by entering the traded market. As such, these LoLP spikes at Gate Closure resulting in high cash-out prices do not represent a transparent market signal that market participants can react to. Rather it is simply an ex-post penalty or bonus which parties have little visibility of.
GDF SUEZ UK-Turkey	**Four hours ahead** Whilst GDF SUEZ prefers the dynamic LOLP function, if a static LOLP function is introduced then it should be fixed such that market

Respondent	Response
	participants can respond to the signal (or not if the value is low). Fixing LOLP 4 hours ahead of the settlement period would give time for the market to react to the signal.
RWE Supply and Trading GmbH	**One hour ahead (Gate Closure)** The LOLP prior to gate closure in order to facilitate trading of positions in response to the market signal. The timing of the publication of an ex ante LOLP is important in driving market participant balancing behaviour.
SmartestEnergy	**One hour ahead (Gate Closure)** At Gate Closure, as this would be the most realistic estimate of the de-rated margin for the relevant Settlement Period. Participants should not be trading against a known value as at two hours ahead, as it is akin to trading against a known imbalance price. LoLP forecasts will be available for this purpose.
Flow Energy	**24 hours ahead** A static LoLP should be determined 24 hours in advance to allow suppliers to trim their position day ahead rather than within day.
InterGen UK Ltd.	No comment at this time.
National Grid	**One hour ahead (Gate Closure)** Under a static solution we believe that the final LoLP should be determined at Gate Closure. We recognise the trade-off between certainty and accuracy highlighted by the workgroup in consideration of this question. However, we would suggest that the extent of accuracy that may be eroded by applying a de-rated margin beyond two hours ahead would seem to have the potential to impose inappropriate imbalance prices on market participants, creating market inefficiencies. The intent of the original EBSCR RSP policy was to improve how well the cash-out price reflects the value that accepted reserve actions provide to the market. Using de-rated margins from greater than two hours ahead to derive the RSP may drive disproportionate incentives on market participants that are not reflective of the prevailing conditions or the needs of the system for the relevant Settlement Period to which the RSP applies. We would consider a two-hour ahead final LoLP as the next best option after a Gate Closure LoLP.
DONG Energy	**One hour ahead (Gate Closure)** DONG Energy is not fully convinced that a static LoLP will be its preferred solution, however we believe that the Final LoLP value should be determined one hour ahead of Gate Closure to leave sufficient time for market participants to account for expected system stress.

Respondent	Response
Good Energy	**At least four hours ahead** Whichever lead time is chosen is a trade-off between early certainty of the RSP and the accuracy of the forecasted de-rated margin, whilst giving parties sufficient time to respond to the signal. A lot of the uncertainty in the forecast de-rated margin in the 24 hours ahead of real time comes from how much the wind forecast may change during this time and the Transmission Company has pointed out that the mean absolute error in the wind forecasts, which is measured in relation to the metered capacity, improves from 5% at 24 hours ahead to 3% at Gate Closure, based on 2013 data. We would need the Final LoLP value to be determined a minimum of 4 hours ahead of real time in order to have a reasonable opportunity to try and trade out our expected imbalance position but we understand that other smaller parties may need longer than this.
Centrica	**Two hours ahead** We support the publication of the final LoLP value two hours ahead of real time. This should give market participants one hour before gate closure in which to react to this signal as appropriate.
RenewableUK	No opinion
Electricity North West	Not applicable to Distributors.
VPI Immingham	**One hour ahead (Gate Closure)** Should the alternative static function be implemented, we believe that it should also be determined at gate closure as it would then be based on the most accurate forecast of the de-rated margin for that settlement period.
UK Power Reserve Ltd	We have no strong preference but feel that the timing should balance simplicity of implementation and reflect value/accuracy equally.
Green Frog Power	**As soon as possible** We agree with the views of the workgroup, that in the interest of transparency, the final LoLP value should be published as soon as possible.
Vattenfall	-
Eggborough Power	-
Haven Power Limited	**At least two hours ahead** We consider that there is merit in setting the de-rated margin ahead of gate closure, at least two hours ahead of the Settlement Period (SP). The analysis to date has revealed sudden spikes in LoLPs between two hours ahead of the SP and Gate Closure. This is

Respondent	Response
	probably capturing last minute plant trips just before gate closure. We do not believe that the RSP Function should be seeking to send signals related to sudden last minute plant trips or that these events should be reflected in cash-out prices. Such events are unlikely to reflect the underlying degree of scarcity on the system. Additionally, at Gate Closure it is not possible for a market participant to react to this increased LoLP signal and effectively mitigate the impact by entering the traded market. As such, these LoLP spikes at Gate Closure resulting in high cash-out prices do not represent a transparent market signal that market participants can react to. Rather it is simply an ex-post penalty or bonus which parties have little visibility of.
SSE plc	**One hour ahead (Gate Closure)** Given the increased ability to forecast and respond to static LoLP signals as they develop through the day, we believe that calculation at Gate Closure is appropriate. Anything greater than 4 hours ahead seems excessive.
First Utility Limited	**24 hours ahead** The LOLP function should operate at times of scarcity to produce a market signal for parties to take appropriate action. The proposed does not provide a reliable market signal to encourage trading and development of liquidity in appropriate risk mitigating wholesale electricity products. It also has potential to trigger LOLP at unexpected times. The plant margin at 24 hours ahead is a good broad indicator of plant availability. Demand at 24 hours ahead is also reasonably well understood and reliable. In order to forecast LOLP, parties need to be experts in demand forecasting, plant availability monitoring and renewable (especially wind) forecasting. Players who are active in all areas will have a distinct advantage. Smaller players without critical mass of expertise will struggle, and a trade-off therefore needs to be made between the advantage of increased market efficiency by having a signal close to gate closure and the administration and additional risks faced by parties trying to trade against this. On balance we believe the quality of the scarcity signal does not significantly improve from 24 hours ahead. A static LOLP function determined 24 hours before the settlement period, would give a clear indication of impending shortage and give enough time for parties to take appropriate action, whilst still providing a strong market-based signal.
E.ON	**Two hours ahead** For parties to have a chance of acting on any LOLP the latest possible time that one could be published would be an hour before

Respondent	Response
	Gate Closure. This could give parties a final chance to change bids/offers and potentially dispatch plant, though at such short notice options would be very limited. (As far as RSP is concerned, we would highlight that to be a true reflection of scarcity, RSP should only apply to STOR actions taken when all available bids/offers have been utilised. Sometimes STOR is called upon instead of a BOA; such instances must not be priced at a 'scarcity' value).
Stark Software International Ltd	No Response
Utilita	Not addressed in this submission
Cornwall Energy	**Four hours ahead** We support an early publication of the final LoLP function to provide information to market participants to trade to avoid the charge. However, a balance must be struck between accuracy and provision of useful information. As the analysis provided by National Grid showed, the accuracy of the LoLP calculation increased as gate closure drew near; however changes at the last minute were also apparent as a result of plant trips. Many smaller participants are only able to make changes to their position if given notification four hours ahead of time. We would therefore prefer the final LoLP value to be set four hours ahead of gate closure.
EDF Energy	**One hour ahead (Gate Closure) or two hours ahead** We believe that Gate Closure provides the most realistic and accurate measure of LOLP, while fixing 2 hours in advance of delivery provides a relatively accurate figure, while allowing parties time to trade based on it. Fixing LOLP well in advance of Gate Closure could result in parties being exposed to a high LOLP when the market had taken corrective action to avoid a loss of load; or conversely, not incentivise parties to take corrective action in the event of a loss of load becoming more likely following the fixing.
Co-Operative Energy	**Four hours ahead** We believe that four hours ahead of the settlement period strikes a suitable balance between sufficient prior notice for planning and risk assessment purposes by participants and a realistic near-term view of the situation for LoLP determination.

Question 10: Do you agree with the proposed VoLL values and the phased approach to implementing this parameter?

Summary

Yes	No	Neutral/No Comment	Other
13	7	9	1

Responses

Respondent	Response	Rationale
Western Power Distribution	-	We do not have a view on this.
ScottishPower	Yes	We agree that a reasonable case for the use of a VOLL of £6,000 was presented in the Electricity Balancing SCR, We further agree that a phased introduction, beginning with a VOLL of £3,000 on implementation, would allow Parties time to adjust to the impact of the VOLL upon imbalance prices. However, we note that European cross boarder coupling algorithms are not designed to cope with prices of this nature. We can envisage outcomes whereby these levels may need to be reconsidered to align with European market integration.
IMServ (Europe)	-	No view
TMA Data Management Ltd	No comment	-
Drax Power Limited	No	In principle we consider that there is merit in setting a price for involuntary demand disconnections. However, the price at which this is being proposed does not appear to have been sufficiently tested to understand the potential impact on independent parties. The high prices indicated have the potential to cause serious financial damage to independent businesses. Analysis undertaken by Ofgem on the impact of potentially high cash-out prices on company revenues fails to take into account that many businesses are operating high revenue, low margin businesses. We would prefer to see a lower VoLL due to our concerns regarding the potential impact on smaller parties. A VoLL beginning at £2,000/MWh and increasing to £3,000/MWh in 2018 represents a more prudent approach in our view.
GDF SUEZ UK-Turkey	Yes	These have been well signalled and there has been no justification of any alternative VOLL value.

Respondent	Response	Rationale
RWE Supply and Trading GmbH	Yes	We agree with the rationale for phased implementation as set out in the EBSCR.
SmartestEnergy	Yes	An ultimate VoLL of £6000 seems reasonable as does an interim value of £3000 for the first 2-3 years. However, we believe it should be indexed from the point it is set to £6000.
Flow Energy	Yes	-
InterGen UK Ltd.	Yes	The proposed phased approach for implementing VOLL seems reasonable and in line with the proposed phased introduction of PAR reduction.
National Grid	Yes	The proposed levels of VoLL have been signposted to industry since the publication of the EBSCR Draft Policy Decision, later confirmed in the May 2014 Final Policy Decision. For the reasoning set out in the EBSCR, we support these levels and in the interests of safeguarding market confidence in the policies believe it is important to be faithful to those levels.
DONG Energy	No	DONG Energy believes that the proposed VoLLs are appropriate for the cost reflective incorporation of the RSP under PAR500 but are disproportionate for the purpose of introducing an imbalance price for demand control actions as explained in response to Question 1.
Good Energy	No	We believe that if instructed to implement demand control measures, Distribution Network Operators would prefer where practicable to undertake voltage reduction measures in preference to disconnecting demand (and potentially simultaneously disconnect adjacent embedded generation). In our experience customers generally rarely notice voltage reduction measures and that this should be reflected in a lower value to VoLL than is proposed. We are also concerned that when the market expects high levels of LoLP, liquidity in the intraday market may dry up leaving us exposed to very high imbalance prices driven by VoLL. We believe a pragmatic approach should be adopted whereby VoLL is introduced at £2000/MWh and remain at that level for at least 2 years while parties gain experience of the changed market conditions and it becomes clearer what happens to market liquidity when potentially very high imbalance prices are expected, with any further increases to VoLL being initiated by the proposed VoLL review process.

Respondent	Response	Rationale
Centrica	Yes	-
RenewableUK	-	No opinion
Electricity North West	-	Not applicable to Distributors.
VPI Immingham	Yes	Yes, we agree with the proposed VoLL values and the proposed phased approach as the values will incentivise participants to balance their position. It should be noted that the proposed step change in PAR and VOLL in 2018 could have a significant impact on cash out costs and therefore the more notice given of the costs and changes, the better. With 2018 being the first capacity mechanism delivery year, some consideration must also be given to any interaction between the higher VoLL value and the capacity mechanism.
UK Power Reserve Ltd	No	UK Power Reserve believes that a timelier implementation would be better served but otherwise has no objections to the values proposed.
Green Frog Power	Yes	We agree with the values but the highest value should be brought in as soon as possible – the sooner it is brought in the sooner there will be less imbalance and therefore lower overall costs for consumers.
Vattenfall	-	-
Eggborough Power	-	-
Haven Power Limited	No	In principle we consider that there is merit in setting a price for involuntary demand disconnections. However, the price at which this is being proposed does not appear to have been sufficiently tested to understand the potential impact on independent parties. The high prices indicated have the potential to cause serious financial damage to independent businesses. Analysis undertaken by Ofgem on the impact of potentially high cash-out prices on company revenues fails to take into account that many parties are operating high revenue, low margin businesses. To illustrate this consider a small supplier with predominately NHH customers. Consider a party that has annual volume of 100GWh and for simplicity assume an average wholesale electricity price of £50/MWh. If a disconnection occurs during a winter peak period and they are short by 2MW

Respondent	Response	Rationale
		during this period (approx. 10% error), then the cost of this is £3000 (£6000 from 2018). While this cost is only (£3000/£50m) 0.06% (0.12% from 2018) of their annual energy costs if we assume a profit margin of £2.50/MWh then this will reduce their annual profit margin by 1.2% (2.4% from 2018). If a disconnection event happens then there is usually a significant chance of another one happening either in the consecutive half hour or during the following few days. Six of the ten highest LoLP values in 2014 occurred between 12th – 16th October. If disconnections occurred across three HH periods on two consecutive days then this would reduce the annual profit margin by 7.2% (14.4% from 2018). Furthermore, it is unlikely that a small party would be able to cope with credit cover or cash flows during this period. The average SBP associated with these 6 high LoLP values in October was £315. Unfortunately the Elexon analysis does not include these dates to allow us to see what the SBP may have been under a lower PAR regime. **We would prefer to see lower VoLL prices for disconnection events as we are concerned of their effects on smaller parties. Values starting off at £2000 and increasing to £3000 in 2018 seem more reasonable to us.**
SSE plc	Yes	SSE agree that an administered VoLL price is necessary to price current unpriced actions associated with demand curtailment, given the inability to observe true VoLL prices in the current market (noting this may change with Smarter Markets arrangements). Whilst the VoLL values proposed do not directly relate to the value reported in the supporting VoLL study, i.e. are not set at the average VoLL of £17,000/MWh; we understand the rationale applied to reduce the proposed values and have no objection to them being introduced as they are both sufficiently high to make cash-out more credible as a penal price under tight system conditions and provoke a change in forward behaviour by market players. We support a phased approach as this allows a period of adjustment for the market to become used to a VoLL parameter in the pricing equation at a

Respondent	Response	Rationale
		reduced value initially.
First Utility Limited	No	We agree with the proposed value of £3000. This value should only be changed through a modification under the scrutiny of a workgroup. We do not agree with hardwiring a change to £6000 until we have seen the results of actual data analysis as a result of the initial changes.
E.ON	No	Definitely not without further consideration of the potential impact of the second phase. We do not see that VoLL will be anything other than a penal charge beyond parties' control that would simply result in excessive costs that will ultimately impact consumers. While the intention behind the VoLL values put forward may have been to complement values applicable in the CM, the range in customer views on VoLL and fact that the original figure utilised by London Economics is based on Willingness to Accept not Willingness to Pay naturally raises concerns that the numbers are overly high. In practice it is also very hard for parties to get a decent understanding of what impact the proposed levels might have when the historical analysis made available for this Assessment Consultation has used only the initial £3,000/MWh figure in RSP, and also no Demand Control actions were undertaken that would have incurred the full £3,000 or £6,000/MWh cost. It would seem risky for a decision to be taken to go ahead with this step up to £6,000/MWh in Nov 2018 – a predetermined figure and at a predetermined date – when parties have not been given a chance to assess what impact this might have, and notwithstanding any other changes that take place before winter 2018-19. In 2012 however we believe that data based on £6,000/MWh was provided; it would be helpful if further work could be done now on this aspect of the proposal before any such phase is determined.
Stark Software International Ltd	-	No Response
Utilita	-	Not addressed in this submission
Cornwall Energy	Yes	We agree with the proposed VoLL values as arbitrarily high numbers intended to signal the cost of demand disconnections. We agree that a phased approach to

Respondent	Response	Rationale
		implementation is preferable, giving market participants experience at lower values before increases occur.
EDF Energy	-	The Value of Lost Load (VOLL) proposed is designed to create cashout prices reflecting the lost value for consumers of unmet demand in the event of a loss of supply due to insufficient national energy. Under the proposal, it would be used both in determination of an estimated scarcity value of electricity in advance, dependent on the estimated probability of scarcity occurring, and as the value of the deemed balancing action of actual involuntary demand reduction if it occurs. This is expected to incentivise parties to avoid such an event in the first place, by avoiding shortfalls that could or do result in demand control being necessary. In recent decades, loss of supply events due to energy shortfalls have tended to be random and unforecastable, as seen by the initiation of automatic Low Frequency Demand Disconnection (LFDD) in May 2008 and Demand Control instructed by NGET in February 2012. We note that the workgroup considers that LFDD should be considered an unpriced "system" action to control frequency, like Demand Control resulting from network faults or network constraints, rather than an "energy" action priced at VOLL and able to set imbalance price. Nevertheless VoLL could effectively hit parties in cashout at random. The true VOLL varies with consumer and circumstances, but is generally likely to be lower when the weather is warmer, and in the middle of the night. Use of a time-dependent VOLL could better reflect the true value. It is important to ensure that there are no perverse incentives on parties to deliberately cause a loss of supply to customers while holding a long position in order to cash in on high System Sell prices approaching, at, or above VOLL. We think the risks of this are small. We believe it is impossible to accurately model the behavioural changes this modification may cause. As such, we feel it is inappropriate to introduce an automatic escalation of the VoLL value. Instead, we feel that changes to VoLL should be proposed either by a BSC Party, or any of the other bodies who are currently able to do so, including Citizens Advice and Citizens Advice Scotland, raising a BSC Modification Proposal, and the proposal being

Respondent	Response	Rationale
		subject to the appropriate level of governance.
Co-Operative Energy	Yes	We are of the view that, should a situation arise where VoLL charges need to be applied, these need to create a sufficiently strong incentive on all market participants to take all necessary steps to balance themselves. Our opinion is therefore that the VoLL values, although high, are appropriate.

Question 11: Do you believe that a maximum interval between VoLL reviews should be implemented?

Summary

Yes	No	Neutral/No Comment	Other
3	16	11	0

Responses

Respondent	Response	Rationale
Western Power Distribution	-	We do not have a view on this.
ScottishPower	Yes	It is unlikely that the value assigned by consumers to energy security will vary significantly in the short-term and therefore it should not be necessary to review VOLL on a frequent basis. We would therefore suggest that VOLL reviews should be infrequent and that any change to VOLL should not be implemented in a period less than the period normally traded ahead i.e. 18 – 24 months in order to allow Parties to factor the impact into forward prices. We do not see the need for a maximum interval to be set between VOLL reviews as Parties or the Authority would be able to ask the Panel to carry out a review at any time (while respecting the minimum implementation timescales suggested above).
IMServ (Europe)	-	No view
TMA Data Management Ltd	No	We agree with the VoLL review process put forward by the workgroup: the VoLL review can be initiated by the Panel at any time and the Authority can request a review from the Panel. The review must include consultation with the Industry and allow the Panel to raise a Modification with no prescribed lead time to change the VoLL if the review findings require it.
Drax Power Limited	No	We do not consider that there needs to be a maximum interval between VoLL reviews. We think it is sufficient to review VoLL on an ad hoc basis as and when deemed necessary. If a significant increase in the VoLL is proposed, we consider a minimum of six months' notice will be required to provide parties adequate time to respond efficiently to the change.
GDF SUEZ UK-	No	Market participants can raise a modification to change the level of VOLL. A regular review is not

Respondent	Response	Rationale
Turkey		necessary.
RWE Supply and Trading GmbH	No	It is essential that there is stability associated with the key administered parameters in cash out. A VOLL review process which includes industry consultation prior to implementation of any change would appear to provide sufficient safeguards to ensure that a thorough assessment takes place. Implementation of a VOLL change should be signalled to the market in advance with sufficient lead time to enable the market to respond.
SmartestEnergy	No	We are not in favour of institutionalising reviews. A value should be set and challenged using the modification process. £6000 may be a rather undynamic figure but it is at least in keeping with the value under the Pool (plus inflation). Until such time as a more dynamic VoLL can be determined we think that it should be set but with indexation. The proposed solution, however, is preferable to one which could see Ofgem directing change.
Flow Energy	Yes	VoLL should be reviewed on an annual basis.
InterGen UK Ltd.	-	No comment at this time
National Grid	No	We do not hold a strong view on this issue and would support a solution with or without a maximum interval. However we agree with the reasoning of the workgroup consensus that changes to the VoLL are more likely to be sporadic and significant than little and often. Furthermore we are comfortable that the proposed solution provides sufficient means for industry parties and bodies to review the level of VoLL as and when required.
DONG Energy	No	DONG Energy believes that the VoLL should be reviewed whenever the industry judges it insufficient to represent the cost of the measures priced with it through the usual modification process.
Good Energy	No	We agree with the Workgroup that it is very unlikely the VoLL value would be one that would change little and often, that a process could be developed that gave industry clear sight on potential changes, and that any proposed changes would likely be more significant in response to changes in the prevailing market conditions. However, when VoLL is introduced we would like it to be fixed at the initial value for at least 2 years while parties gain experience of the changed market conditions and it

Respondent	Response	Rationale
		becomes clearer what happens to market liquidity when potentially very high imbalance prices are expected.
Centrica	No	We do not consider it necessary to introduce a maximum interval between VoLL reviews.
RenewableUK	-	No opinion
Electricity North West	-	Not applicable to Distributors.
VPI Immingham	No	Market conditions could change at any time such that a review of VoLL is required. However, we believe that VoLL will not change by small amounts, frequently, but is more likely to change by large amounts, infrequently. The proposed solution would enable modifications to change the value of VoLL to be raised at any time and therefore a change could be initiated by industry participants, negating the need for a maximum interval between reviews.
UK Power Reserve Ltd	No	Although of no strong opinion we would be against such limitations on flexibility within the system.
Green Frog Power	-	-
Vattenfall	-	-
Eggborough Power	-	-
Haven Power Limited	No	We do not consider that there needs to be a maximum interval between VoLL reviews. We think it is sufficient to review VoLL on an ad hoc basis as and when deemed necessary. **If VoLL is to be increased significantly the industry should be given at least 6 months' notice.**
SSE plc	No	SSE do not believe that VoLL is a parameter that will be subject to regular change, as it implies a corresponding study to be conducted that supports any change in value. We do not believe that it would be efficient to conduct such a study on a fixed interval basis, say every one to two years. We are comfortable with the arrangements proposed to allow the Panel and Ofgem via the Panel to initiate a review, and also note that any BSC Party has the right to raise a modification to propose a change (which we assume would trigger a corresponding study), once the parameter is in effect.

Respondent	Response	Rationale
First Utility Limited	Yes	First Utility would be very concerned if VoLL was to fluctuate substantially as this would lead to more uncertainty and risk. We therefore have a balance between performing the review too frequently - leading to unnecessary administration but smaller VoLL changes and too infrequently - leading to large step changes in VoLL. Large changes of VoLL could lead to adverse publicity and media attention for BSC parties. We suggest that a maximum interval of 5 years is embedded within the BSC to ensure it is reviewed automatically should no parties request a review during that 5 year period.
E.ON	No	We are supportive of taking an approach similar to that of the MIDS review with industry consultation on both the level and lead-time for implementation of any change in value. However, not convinced that a maximum review period would be helpful. While some might feel that a regular review could give comfort that a party was unlikely to raise an unexpected proposal, this would still be a risk and a regular review could just require unnecessary work for a value that is unlikely to require regular/small changes. The fact that the Panel could instigate a review on the request of the Authority or a party raise a proposal means that the intervals between reviews might not be exactly annual, but this should give Ofgem the comfort that a change could be raised at their request at any time if deemed desirable; ultimately the Authority would still approve whether or not to implement a change.
Stark Software International Ltd	-	No Response
Utilita	-	Not addressed in this submission
Cornwall Energy	No	We do not think a maximum interval between VoLL reviews should be implemented, as industry should be able to change a value which has negative impacts as quickly as possible. The review process with industry consultations should provide enough time for industry participants to be aware of changes to VoLL.
EDF Energy	-	EDF Energy believes that VOLL used in the BSC should only be changed as part of a BSC Modification, which provides an appropriate level of review and governance. Periodic reviews of the value under the BSC may be useful, but we have no

Respondent	Response	Rationale
		strong view at this time on a preferable mandatory maximum interval.
Co-Operative Energy	No	We do not believe that this would add any value as situations may arise where VoLL needs to be reviewed at short notice in light of new evidence or market developments.

Question 12: Do you agree with the proposed approach to correcting NHH Suppliers' imbalance volumes following a Demand Control event?

Summary

Yes	No	Neutral/No Comment	Other
12	4	10	4

Responses

Respondent	Response	Rationale
Western Power Distribution	-	We do not have a view on this.
ScottishPower	-	Suppliers' imbalance volumes should be adjusted in the most cost effective manner following a Demand Control event.
IMServ (Europe)	No	Although a centralised approach of NHHDA is implied and seems the most logical and robust, the impact on the NHHDC is unclear – response to Question 16. Also please see comments to question 3 which questions the inclusion of NHH sites PC 1 – 4.
TMA Data Management Ltd	Yes	We would like clarification on whether the NHH approach proposed would be fulfilled partly by the centralised EAC/AA module.
Drax Power Limited	N/A	We are not best suited to answer this question.
GDF SUEZ UK-Turkey	No comment	-
RWE Supply and Trading GmbH	Yes	We note that the proposed arrangements are complex and will only ever produce an estimate of the appropriate supplier imbalance volumes. However, this is more appropriate that not adjusting the volumes.
SmartestEnergy	-	It states that the detailed description of this proposal is in Attachment A. We cannot find Attachment A.
Flow Energy	Yes	-
InterGen UK Ltd.	-	No comment at this time
National Grid	Yes	Given the complexities involved in performing this volume correction, the proposed approach seems to

Respondent	Response	Rationale
		be logical.
DONG Energy	Insufficient Assessment	DONG Energy believes that the most accurate and cost efficient solution should be implemented to correct NHH Supplier's imbalance volumes following a Demand Control event. Requirement 8 outlined in Attachment A appears to fulfil these criteria following the explanation in the Assessment Consultation Response Document. However, we do not feel that sufficient assessment has been undertaken to make an informed decision.
Good Energy	Yes	The proposed method appears to be both cheaper to implement and operate and also more accurate than any of the three options proposed in the Impact Assessment. We consider it important that the method for correcting NHH Suppliers' imbalance volumes following a Demand Control event is relatively accurate due to the risk such events impose on trading parties. Although they may occur infrequently each one could have significant effect on some parties' imbalance charges due the impact of VoLL.
Centrica	Yes	This method is likely to be cheaper to implement and more accurate than other discussed.
RenewableUK	-	No opinion
Electricity North West	No	This seems to be a very expensive solution with no justification. As indicated earlier we believe that this solution should be compared to the 'top down' approach in order to see what improvement in accuracy is achieved compared to the additional costs in doing so.
VPI Immingham	No comment	N/A – not in a position to comment
UK Power Reserve Ltd	-	No comment
Green Frog Power	No	We are not satisfied that this methodology has been sufficiently well considered in the full context of cash out reform. Furthermore, we believe that there are some potentially serious risks to suppliers should this be prematurely or poorly implemented. Therefore we think this element of P305 should be progressed as a separate modification.
Vattenfall	-	-
Eggborough Power	-	-

Respondent	Response	Rationale
Haven Power Limited	Yes	While the requirements appear quite complicated we believe the approach is sensible. It certainly appears to remove some of the problems associated with the previous proposals.
SSE plc	-	If application of an artificial Supply volume to correct imbalances is considered to be the optimum incentive, then SSE support the proposed approach as it needs to be as robust and equitable as possible. We are concerned about the potential impacts of a Supplier being left short under this approach, when that Supplier has responded to market signals rationally and contracted to balance their forecast position upto Gate Closure. Could an alternative incentive, such as license condition, provide similar benefits?
First Utility Limited	Yes	We believe this is an appropriate approach to resolving the issue.
E.ON	Yes	The Workgroup's proposed approach per Requirement D8 seems satisfactory for what should be a very rare event.
Stark Software International Ltd	Yes	Less concerned with NHH proposals as they would be presumably centrally developed and automated.
Utilita	-	Not addressed in this submission
Cornwall Energy	Yes	We agree with the proposed method if demand disconnection volumes have to be estimated.
EDF Energy	No	EDF Energy believes that "correcting" NHH Suppliers' imbalance volume would have the effect of increasing the amount of unbillable power that Supplies are required to deal with. It is not clear that this cost should be borne by suppliers. The proposed approach appears to be the best of the considered options in terms of accuracy and efficiency. The proposed adjustment of individual supplier imbalance volumes as an estimate of the impact of demand control (detailed solution Area D5-D9) is complicated, and even the more accurate methods of adjustment will only be approximate. We think they will be very difficult to implement successfully in the timescale envisaged. The desire to adjust volumes is to avoid the possibility of windfall gains for suppliers resulting from demand control of their customers. However, the event is likely to be rare

Respondent	Response	Rationale
		and the materiality of the benefit of adjustment has not been clearly identified. There will not necessarily be windfall gains, if competing suppliers reflect potential rare imbalance benefits resulting from demand control, which can be viewed as a risk reduction, in customer tariffs. We think further consideration of the costs and benefits of adjusting supplier positions, or other means of providing efficient incentives, should be considered in a separate modification. For example, payment of compensation to those demand-controlled consumers who are considered to be paying for a particular level of security in their tariff might actually be more effective in the long term, if effective practical methods can be devised. Payment of compensation to suppliers who may have procured expensive energy to satisfy time-of-use tariffs may also be required to avoid penalising innovative tariff approaches through imbalance volume adjustments. Methods of determining demand control and/or demand response volumes for individual suppliers may be required in the long term as "smarter markets" develop, but we are not convinced that the proposed solution for demand control adjustments is justified currently.
Co-Operative Energy	Yes	This seems a reasonable approach.

Question 13: What impacts do you believe P305 will have on the BSC credit arrangements?

Responses

Respondent	Response
Western Power Distribution	We do not have a view on this.
ScottishPower	We believe that P305 may result in Parties deciding to post additional credit with ELEXON to cover potentially increased imbalance cashflows arising from more extreme imbalance prices. Due to the short time period during which Parties can correct a credit breach and the reputational risk associated with a breach of the credit arrangements, Parties may be inclined to post additional credit to avoid this risk. To some extent this risk may be mitigated by other Modifications under consideration e.g.P307 although these Modifications are not contingent upon each other.
IMServ (Europe)	No view
TMA Data Management Ltd	P305 may have an adverse effect on the level of credit cover that Parties must have in place as the price of the most expensive 1MWH actions will be included in the imbalance price calculation rather than the average of the most expensive 500MWH as it is done currently. That being the case, it would impact Small Suppliers more keenly. P305 attempts to make imbalance prices more reflective of the actual cost of the imbalance actions taken by the System Operator; in doing so, it demands more efficiency from all parties, which should be supported. A natural consequence might be a higher level of credit cover in monetary terms. We take note of current modifications (P307, P308 and P310) still under review to make the credit cover and credit default processes easier and could mitigate some of the difficulties that P305 could introduce.
Drax Power Limited	We consider it will increase the required credit that needs to be posted. This appears to be the likely result of creating more spikey and volatile cash-out prices. It is not clear if all parties will be able to submit sufficient credit cover in an extremely volatile period. It may be necessary for parties to make short term increases in credit cover in such periods. However, we have not been able to quantify theses impacts.
GDF SUEZ UK-Turkey	As noted in the Assessment Consultation, credit arrangements will increase due to the potential for very high cashout prices.
RWE Supply and Trading GmbH	Credit cover may need to adjust to reflect the implementation of P305 but no change is required to the credit arrangements
SmartestEnergy	There will inevitably be some impact if imbalance costs increase. However, we do not believe this will be significant. For one thing the industry is massively over-collateralised anyway and the effect will not be so great.

Respondent	Response
Flow Energy	The impacts will not change the nature of the credit arrangements, but smaller, independent suppliers may be required to have additional cover.
InterGen UK Ltd.	There may be a modest change in the amount of credit cover we are required to post, although this is unknown at present and entirely dependent on the level of PAR and the capacity margins across the winter.
National Grid	National Grid's credit arrangements will not be impacted by P305. However, we are aware that there is potential for the Credit arrangements of some parties to be impacted, though it is difficult to comment on the extent of these impacts for other organisations.
DONG Energy	DONG Energy believes that due to higher imbalance prices there will be higher credit cover requirements.
Good Energy	The historic analysis undertaken by Elexon shows that the introduction of single cash out prices reduces imbalance cash flows for all party types but that this benefit is consistently eroded as PAR is reduced. However, the historic analysis has been undertaken during a period of relatively benign market conditions and P305 will doubtless lead to behavioural change. Lower average imbalance charges would reduce average indebtedness under the BSC credit arrangements. However, the increased volatility of imbalance prices will cause sudden, more rapid, changes in indebtedness and for us to manage this within the BSC credit arrangements may lead to an increase in the credit cover lodged and/or require us to keep further cash in reserve to be able to respond to the more challenging situation.
Centrica	We suggest that the level of credit that market participants are required to post will increase over time once this modification has been implemented. If the imbalance price should be set at VoLL this will significantly impact the credit requirements for all parties.
RenewableUK	No opinion
Electricity North West	Not applicable to Distributors.
VPI Immingham	Higher balancing costs could have an impact on the amount of credit that parties have to post. However, having looked at our credit position and potential changes, we do not believe that this would be a material cost. We would not expect huge changes to our credit lines and the corresponding cost of these could be expected to be negligible.
UK Power Reserve Ltd	We feel that whatever the end result of P305 on the BSC credit arrangements that they will be appropriate considering the wider strategic objectives of the BSC and cash out reform.

Respondent	Response
Green Frog Power	Parties who are worried about increasing exposure to cash-out are likely to post more credit. However as the CAP has just gone down, and forward prices are looking lower, this may outweigh the increasing exposure some parties may feel. We agree with our counter-parties that credit is a huge issue in the market, but much of the problem sits with the credit required by the larger players from their counter-parties.
Vattenfall	Vattenfall believes that it is likely that higher imbalance cost will lead to a requirement for higher credit cover.
Eggborough Power	Both P316 and P305 could incentivise parties to lodge more credit because they increase the risk that being out of balance is more expensive than it currently is (assuming Ofgem's outcomes are met).
Haven Power Limited	We believe it is likely to increase the required credit that parties need to post. **It is not clear if all parties would be able to submit sufficient credit cover in an extremely volatile period such as a disconnection event. It may become necessary for parties to make short term increases in credit cover when such an event occurs.**
SSE plc	The increased sharpness in imbalance price arising from marginal pricing is likely to increase Parties assessment of their peak imbalance exposure and therefore the most likely impact is to increase the length of credit positions currently held, to mitigate the risk of credit default and its associated implications. Plant trip risk is particularly heightened as prices become more marginal.
First Utility Limited	We believe that credit requirements will increase for First Utility and indeed all independent suppliers which will require funds to be reallocated from other activities within these supply businesses, resulting in lower customer acquisition and fewer customers benefitting from the growing competition in supply.
E.ON	We have not examined the potential credit impacts in-depth but it stands to reason that any increase in cashout costs and/or volatility is likely to lead to increased credit requirements. Further consideration should perhaps be given to the potential impacts in a situation where Supplier volumes are to be subject to an adjustment, owing to the time limitations of the bottom-up calculation.
Stark Software International Ltd	No Response
Utilita	Utilita believe that as reducing PAR to 50MWh and then 1MWh would significantly increase both imbalance prices and the volatility of those prices while reducing predictability, this will lead to increased credit requirements in the industry. While the credit cover may not be fully utilised, the potential spikes in prices, coupled with the stringent BSC requirements would mean parties may need to

Respondent	Response
	include more headroom in the cover provided. This would increase costs to all parties and in our view disproportionately to smaller players. In addition, as suppliers we cannot predict prices or the degree of increase, just that they would be higher and more uncertain. We believe this may leads to inefficient (and costly) levels of additional credit cover being required, adding cost to the industry.
Cornwall Energy	With an increase in PAR and imbalance prices the level of credit to be posted will increase, and this has a direct impact on participants, especially those not able to easily access sources of collateral. Including the cost of demand disconnection and the Reserve Scarcity Pricing function could add un-forecastable and large elements into the credit calculations, which could significantly increase credit requirements.
EDF Energy	Most of the time, the cancelling effects of single price should outweigh the increased volatility of cashout prices, reducing the required levels of BSC credit. However, occasional spikes might result in credit events for individual participants, and there could be increased requirement in times of sustained scarcity (or surplus energy creating negative spill prices). These effects are probably minor compared with impacts on bilateral market credit of price feedback into market trading.
Co-Operative Energy	We believe that balancing credit requirements for market participants will increase as cash-out prices increase. This will have a larger cash flow impact on smaller participants who are less able to easily accommodate this increase.

Question 14: Do you believe that commercial terms offered to intermittent generators, under power purchase agreements, will be impacted by any reassessment of balancing risks which may arise following P305?

Summary

Yes	No	Neutral/No Comment	Other
17	0	10	3

Responses

Respondent	Response	Rationale
Western Power Distribution	-	We do not have a view on this.
ScottishPower	Yes	Intermittent generators have intrinsically less certainty over their output and therefore greater exposure to imbalance prices than conventional generators. The purchaser of a power purchase agreement (PPA) with an intermittent generator may have to factor in the increased exposure to uncertain imbalance cashflows arising from the more volatile and extreme imbalance prices introduced by this Modification. The market will have to determine a competitive price for PPAs based upon its assessment of these risks.
IMServ (Europe)	-	No view on the specific question posed. However, why are commercial considerations being restricted solely to this aspect of the process within this question? Why is no consideration being given to other parties impacted by this change?
TMA Data Management Ltd	No comment	-
Drax Power Limited	N/A	We are not best suited to answer this question.
GDF SUEZ UK-Turkey	Yes	Windfarms will pass the balancing risk onto their PPA provider. With most PPAs having a tenor of 5-15 years then for the most part, the cashout changes are only a matter when a new contract is being negotiated. However, some PPA's may contain clauses stating that a renegotiation of price will take place if balancing costs exceed a certain level.

Respondent	Response	Rationale
RWE Supply and Trading GmbH	-	We recognise the increase balancing costs may impact on the commercial terms for intermittent generators.
SmartestEnergy	Yes	We anticipate imbalance costs to increase. *Additional confidential information provided*
Flow Energy	-	We are not in a position to offer a view on this part of the sector.
InterGen UK Ltd.	-	No comment at this time
National Grid	N/A	Commercial terms offered to intermittent generators may be impacted by a change in the imbalance risk resulting from P316; however National Grid is not best placed to comment on the nature or extent of this potential impact.
DONG Energy	Yes	DONG Energy believes that commercial terms offered to generators with variable fuel sources under PPAs will be negatively impacted by a reassessment of the balancing risk resulting from P305. While we expect that there will only be a minor impact from a single price regime compared to a dual price system, we believe that the price for electricity determined in PPAs for these generators will be significantly lower if balancing costs are to rise from higher system prices.
Good Energy	Yes	We believe that commercial terms offered to intermittent generators, under power purchase agreements, will be negatively impacted by a reassessment of balancing risks. There will be multiple one off costs to update generator PPA's to mitigate both imbalance and credit risks and the more contracts in place the higher the relative cost on the supplier in question. How the increased risk itself is reflected in the terms for individual generators will depend on that generator's appetite for risk.
Centrica	Yes	If there is an increase in balancing costs it is expected that offtakers will factor this into discounts given for renewable PPAs. Any reduction to within-day liquidity could have an incremental impact on imbalance costs and discounts may increase. Lower within-day liquidity presents offtakers with an increased risk of not being able to make short term trades to manage out their imbalance position.
RenewableUK	Yes	As balancing charges are priced more marginally to reflect the cost of actions, then variable generators

Respondent	Response	Rationale
		will inevitably see greater discounts applied to the prices offered in power purchase agreements, since their ability to respond to these signals is limited. The move to single cash-out may mitigate this effect, but this is untested and, since PPAs are generally long term instruments, offtakers will likely take a conservative view of its benefit while taking a worst-case view of the charges overall. In the short to medium term, this will cause difficulties for developers bidding projects into the Contract for Difference auctions, as they will be unsure what discount they will have to take into account when calculating strike price offers.
Electricity North West	-	Not applicable to Distributors.
VPI Immingham	Yes	We currently neither offer nor are in receipt of PPAs and are therefore not close to the existing commercial arrangements to comment in detail. However, we believe that the commercial terms offered under PPAs could be impacted, but this is a reflection of the improved balancing signals available to the market – signals that should impact all market participants regardless of how their electricity is generated or sold. Given that PPAs are generally based on a discount against some market reference price with a percentage discount to reflect balancing, higher balancing costs are likely to reflect this discount. However, PPAs are commercial agreements and terms should continue to be agreed on commercial terms by market participants.
UK Power Reserve Ltd	-	UK Power Reserve does believe that there will be impact on some but not all intermittent generators power purchase agreement and the number impacted will be the minority and that these will not be disproportionate to the impact on any other participant. We also believe that the existence of contractual risk and legislative change is well understood in the UK energy market and can be taken into account and mitigated ahead of implementation.
Green Frog Power	Yes	We believe that the commercial terms offered to a number of different parties (ourselves included) may well alter, but that could represent opportunities as well as risks. This is the nature of the market where rule changes are not uncommon; parties adjust arrangements in light of the market structure. Ofgem believed that the signals need to be sharpened to improve balancing, and that will

Respondent	Response	Rationale
		include the signals to all forms of generation and the role they play in helping the system to balance.
Vattenfall	Yes	The cost of a PPA offered to a wind generator covers the cost of balancing. It is difficult to say exactly how the PPA market will adapt to the new legislation. However, some clear possibilities are likely 1) The cost of the PPA which covers the cost of imbalance to the generator is going to increase, to reflect the increased cost of balancing for the off-taker. 2) In the short term, there might also be a substantial risk margin included in the PPA cost to the generator, and the impact on pricing is not yet known. This might lead to intermittent generators choosing to cover the risk of imbalance outside of the PAA. This approach can be seen elsewhere in Europe. This would expose the generator to unknown pricing risk As intermittent generators are more likely to be affected by balancing measures due to the less predictable nature of the generation, this cost is likely to increase the PPA costs by a relatively larger factor than non-intermittent generators. The quantification of this depends on the geographical location of this plant, the size, the variability of the wind (if a wind generator), the relationship between PPA provider and generator, the ability to diffuse costs through a large portfolio and range of other technologies – and ability of the generator to balance through their own portfolio etc. Therefore the impact will be different for different market players. It should be recognised here that one of the unintended consequences of the increase in PPA costs, will be an inflation of strike price bids to accommodate the increased cost. This will increase the cost to the consumer for new renewable energy plant, particularly intermittent generators. This will also affect the competitiveness of intermittent generators within the mix of technologies in each auction Pot. It goes against the BSC Objectives (C) and (F). It is important to also note, as has been recognised in the report, that the ability of intermittent generators to mitigate the impact of this action is limited by the accuracy of forecasting. This is means

Respondent	Response	Rationale
		that although the behaviour of an intermittent generator will adapt, there will inevitably be periods in which the forecasting is inaccurate, and imbalance costs will be incurred. The sharpening then of the prices will be particularly felt by intermittent generators. In addition to this, there will be an interaction with negative pricing and the terms of the CfD which out of necessity hasn't been considered by the working group. The sharpening of prices and the potential increase in the number of negative pricing periods increases the likelihood of a sufficient number of consecutive hours of negative pricing to materially change the level of support received by the project under the CfD. It is not yet know to what degree this will be felt because a) It is not clear how much this will increase the incidence of negative pricing; and b) It has not been decided how precisely negative pricing will be treated under the CfD. However, it is highly likely that the EU 6 hour rule will be applied in some form, and this will discourage intermittent generators from generating. Anything which causes the likelihood of negative pricing reduces the amount of time an intermittent generator can export. This is particularly relevant to intermittent plant as they are less in control of the fuel source, meaning that they can't necessarily make up this lost load at other times in the year. This ultimately means that more installed capacity is needed to deliver the same number of MWh. Even though the impact of this might be marginal now, it is likely to increase as the proportion of intermittent generation in the nation energy mix increases. This can be seen in Germany. This is also in contravention of the BSC Objective (F)
Eggborough Power	Yes	All changes to cash-out will result in players reassessing their commercial arrangements and where the balancing risk sits. Intermittent generation creates additional system costs as it cannot forecast its output as accurately as other parties and these generators should face the costs they create. The question for Ofgem is do these modifications meet the relevant objective, and it is difficult to see that the potential changes in risks will not alter the competitive environment, but it does not appear unduly discriminatory against

Respondent	Response	Rationale
		intermittent plant.
Haven Power Limited	Yes	Due to the difficulties in predicting the consequences of such a large reform, it is likely that parties will be very cautious about the terms that they offer under PPAs.
SSE plc	-	This is a matter for PPA sellers to comment upon.
First Utility Limited	Yes	Many Industrial and Commercial customers along with smaller embedded generators have flexible contracts that are based on a combination of trading and pass through of costs including imbalance costs. Suppliers offer a wide variety of products with various tolerances on the level of imbalance before penalty mechanisms kick in. Most of these contracts will need to be reopened if the relationship between forward traded prices and imbalance prices changes.
E.ON	Yes	The PPA market is very competitive; if imbalance charges increase, intermittent generators are likely to see greater discounts applied to the prices offered for their power: inevitably purchasers will have to consider the increased risk of incurring higher costs for imbalance.
Stark Software International Ltd	-	No Response
Utilita	-	-
Cornwall Energy	Yes	We believe that commercial terms offered to intermittent generators under PPAs will be impacted by the implementation of P305. Wind generators are more likely to be correlated with the system imbalance, especially in the future when wind generation makes up a large percentage of the generation mix. As PAR reduces this will mean offtakers will be required to increase the imbalance discounts they offer to generators, as they face greater risk.
EDF Energy	Yes	A reduction in PAR is designed to lead to more volatile cashout prices, while single price should permit more effective netting of shortfall and spill imbalances. As there is some correlation between intermittent generation and system imbalance, so shortfall and spill do not fully cancel over time, there is likely to be an increase in the balancing risk cost applied to these contracts. A move to a single cashout price may reduce within-

Respondent	Response	Rationale
		day liquidity, as described in Question 16. This may increase the balancing risk on the PPAs, increasing the costs to the client generators.
Co-Operative Energy	Yes	Yes, we believe this will have a negative impact on terms offered to intermittent generators as participants purchasing generation output from these will face increased imbalance risk in situations where intermittent generators are unable to deliver generation output at the times and in the volumes agreed.

Question 15: Do you believe that there will be any impact or interaction between P305 and the Capacity Mechanism & Contract for Difference arrangements?

Summary

Yes	No	Neutral/No Comment	Other
14	10	5	1

Responses

Respondent	Response	Rationale
Western Power Distribution	-	We do not have a view on this.
ScottishPower	Yes	Only time will tell if the introduction of P305 will impact traded products as some envisage. Relying on additional revenues from this change, and therefore altering capacity mechanism bids, will be down to the risk appetite of individual companies. It may take a considerable period of sustained change before some companies are willing to rely on the new price signals. The increased risk from more extreme and volatile imbalance prices may increase the revenue (and strike prices) sought under the CfD arrangements by intermittent generators.
IMServ (Europe)	No	There is no impact on us as an Agent.
TMA Data Management Ltd	No comment	-
Drax Power Limited	No	We consider there will be negligible impact on the Capacity Mechanism and Contract for Difference arrangements.
GDF SUEZ UK-Turkey	-	The proposed cashout arrangements should incentivise parties to balance their contract and meter positions, resulting in a system that is less 'long' than presently. The Capacity Mechanism incentivises parties to meet their load following obligation regardless of whether they have a contractual position. Since the load following obligation is only know after the event, in anticipation of a stress event, generators are likely to over estimate their load following obligation to avoid penalties leading to a 'long' system. However, marginal cashout price should dampen this incentive to over generate as if

Respondent	Response	Rationale
		this drives the system long it would result in payment of spill at a marginal SSP.
RWE Supply and Trading GmbH	No	The energy market will continue to function alongside the capacity market and CFD arrangements.
SmartestEnergy	No	-
Flow Energy	No	-
InterGen UK Ltd.	No	With respect to the Capacity Market, no. Industry has known the outcome of the EBSCR since early 2014 and therefore should have forecast a PAR 1 condition into their market assessment and subsequent Capacity Market bidding strategy for 2018. Implementing a phased reduction in PAR ahead of the first Capacity Market Delivery date (winter 2018) should not have a material impact to future CM bidding strategy (2019 and beyond).
National Grid	Yes	The Capacity Market and the EBSCR policies complement each other to the extent that both seek to address the issue of 'missing money' in terms of the income streams available to capacity providers to recover costs. For the delivery periods from which both sets of policies come into effect (winter 2018/19), we would expect both revenue streams to be taken into account by market participants and factored into capacity market bids and the out-turned imbalance prices.
DONG Energy	Yes	DONG Energy believes that with further evolution of the Capacity Mechanism there will be a more favourable market environment for flexible generation and Demand Side Response leading to a more efficient balancing market as a result. However, DONG Energy does not follow the rationale that higher imbalance prices would have a downward effect on bids in the Capacity Mechanism and therefore provides lower cost to consumers.
Good Energy	Yes	We expect the reassessment of balancing risks to be reflected into the strike price under a FIT/CFD. A portfolio generator may be better placed to manage those risks than a single site, which means single sites will have to seek a higher strike price, and in any auction they would probably lose out to portfolio generators. Therefore the impact will be a restraint on competition in generation from new market entrants and smaller players in the market.

Respondent	Response	Rationale
Centrica	No	-
RenewableUK	Yes	As noted in the answer to Question 14, since developers will have to price in increased but uncertain discounts in offtake agreements to their strike price bids, there may be instances where projects bid too low and suffer 'winner's curse' in the CfD auction.
Electricity North West	-	Not applicable to Distributors.
VPI Immingham	Yes	**Capacity Mechanism** The proposed changes should go some way to addressing the missing money issue that is partly what the capacity mechanism is addressing, but not enough to encourage investment in new, reliable power generation. This is a result of the low load factors that thermal plant are expected to see in the future as increasing amounts of renewable generation come on line. In theory, P305 could result in lower bids into the capacity mechanism in future, but there is so much regulatory uncertainty in the market and potential for unexpected future changes (e.g. new policy as a result of a change in government or changes as a result of the CMA investigation), that it would be very difficult to isolate the impact of P305 itself. With much gas generation in a very precarious position and flexibility not currently valued under the existing market arrangements, the proposals should better reflect flexibility and improve the situation for clean, efficient gas generators. It also provides another route to recover fixed costs for generators and therefore should contribute towards security of supply. However, there is clearly an interaction between LoLP and the capacity mechanism that needs to be carefully thought through. Under a capacity mechanism, you would expect all plant to be available for peak or risk facing penalties for non-delivery which would further impact any LoLP calculation. This interaction should be included in the modelling from the outset. **Contracts for Difference** In terms of Contracts for Difference, again intermittent generators could be expected to be

Respondent	Response	Rationale
		exposed to higher balancing costs which could increase their costs. However, closer to real time, the exact output is highly forecastable and this fits with the timeframes associated with the RSP, allowing generators to take mitigating actions. However, isolating the impact overall would be very difficult with many different policies and Regulations driving costs both higher and lower. However, having a fixed strike price does mean a degree of certainty or these projects and the incentive to balance still increases to maximise profitability.
UK Power Reserve Ltd	Yes	UK Power Reserve feels that there is significant impact on the capacity market auction results from the implementation of P305 and that Ofgem gave a clear indication through published statements during the run up to the auction that P305 should be anticipated to have been fully implemented by the industry and all auction participants. Ofgem also advised all capacity market participants to take account of the impacts of Cash Out Reforms for the December 2014 Capacity Market auction. An extract of the Ofgem statement is referenced below; "The substantial work undertaken during the EBSCR has given us confidence that this package of reforms, which is currently being progressed through Balancing and Settlement Code (BSC) modification P305, drives significant benefits for consumers. We therefore have a strong resolve to see the reforms implemented. We strongly urge the industry to fully consider and acknowledge the significant analysis and consultation that has been conducted during the EBSCR in order to ensure that P305 is progressed in an efficient and expeditious manner. We also strongly advise market participants to fully account for the potential impact of the EBSCR reforms on their businesses now, particularly those bidding into the Capacity Market auctions this December." Ofgem, 28/10/14 It is the UK Power Reserve view that the timely implementation of P305 is critical to avoid the impairing of the capacity market auction results and the entire tender process. To not progress timely implementation of P305 during 2015 could result in the 2015 Capacity Market Auction clearing at a higher price and costing the end consumers more

Respondent	Response	Rationale
		than it otherwise would had P305 been implemented as advised by Ofgem.
Green Frog Power	Yes	P305 will reduce Capacity Market auction prices by encouraging generators to provide the type of capacity that the Capacity Market itself is trying to provide, but on a market-led basis.
Vattenfall	Yes	Yes. This is discussed more fully in question 14. 1) The sharpening of marginal pricing means that it is likely there will be more negative pricing periods. This means that the impact of the treatment of negative pricing under the CfD is likely to be higher. As a result of this, industry will need to have a lower impact policy in place for negative pricing so that it doesn't adversely impact the value of projects under development/with secured CfDs. This lower valuation and increased uncertainty around impact would be reflected in higher strike price bids. 2) The increase in the cost of PPAs is also likely to inflate the strike prices. The possibility that generators start taking on an unknown imbalance risk would also be reflected in returns expectations. This would also inflate strike price bids.
Eggborough Power	Yes	Under P316 there do not seem to be issues with the CM. For P305 the use of cash-out to VOLL would seem to interact with the CM penalties. Arrangements that set a high price in an emergency-type situation can create a risk that there is a "race to the top". This means that under a CM warning the prices could race to VOLL. Eggborough believes this is one of the issues under P305 that needs further consideration as it seems difficult to justify prices at VOLL if not a single customer notices that there is a voltage dip.
Haven Power Limited	No	We consider there will be negligible impact on the Capacity Mechanism and Contract for Difference arrangements.
SSE plc	No	SSE does not believe that the changes proposed will impact detrimentally the EMR arrangements. Indeed sharper cash-out should complement the Capacity Mechanism by ensuring that sufficient flexible capacity is brought forward to be able to respond to sharper scarcity signals.

Respondent	Response	Rationale
First Utility Limited	Yes	We believe this modification will result in greater uncertainty in prompt prices leading to greater uncertainty in the amount of levelisation payments required to be paid by Suppliers for intermittent plant. This consequence will create budgeting and tariff price setting difficulties. Parties in receipt of Capacity Mechanism payments will in theory be able to bid lower prices into the market due to the funds received from that Mechanism. This will create a two tier price stack with a potential dislocation between Capacity mechanism supported plant and those not supported. Having artificial discontinuities in price may cause issues with trading suitable risk management products. We note more generally that if sharper cashout is intended to create signals to invest in plant to increase security of supply, that the capacity mechanism is intended to provide exactly the same benefit.
E.ON	No	Fundamentally the CM is about keeping plant available, not short-term balancing. We do not see the potential impacts of balancing changes as likely to impact e.g. CM bids, where many factors come into consideration.
Stark Software International Ltd	-	No Response
Utilita	-	-
Cornwall Energy	Yes	We expect changes under P305 to have been factored into recent bids into the Capacity Market (they will have increased prices as a result of higher demand to avoid higher charges). For the upcoming CfD auction we expect P305 will have a significant impact as generators will be searching for PPAs to enter into the market with, and expectations of imbalance risk in the future will have a large impact on PPA discounts. Generators without PPAs will be at a competitive disadvantage in the auction as they may be factoring in the discounts from the Offtaker of Last Resort, increasing the strike price bid they will place into the auction.
EDF Energy	Yes	The Capacity Mechanism and Contract for Difference arrangements are designed to improve the security of supply for GB. Following a Capacity Mechanism Warning, parties

Respondent	Response	Rationale
		who have capacity agreements would be under an obligation to self-dispatch to meet their agreements. This has the potential to result in parties being exposed to cashout prices if they are not able to trade out any consequent long position in time. We would expect competitive bid-down prices from marginal plant in these circumstances, despite magnified trip risks and the possibility that NGET may rely on self-despatch up to capacity rather than take explicit expensive offers. It seems unlikely that very low/negative prices would become marginal in this circumstance of relative scarcity. A single cashout price with a reduced PAR makes trading at negative prices on within-day (and hence day-ahead) markets more likely in times of system oversupply. We understand that this may have impacts on the settlement of the proposed "intermittent" CfD arrangements.
Co-Operative Energy	Yes	It seems likely to us that the potentially higher cash-out prices resulting from PAR reduction will affect both the Capacity Mechanism and Contract for Difference arrangements. For the Capacity Mechanism it potentially makes it more likely that plant will need to be dispatched in tight network periods. With regards to Contract for Difference arrangements, we believe that higher cash-out prices will be factored into (and thus raise) market prices, potentially making it more likely that generators with CfD contracts will need to make payments to the market during certain periods.

Question 16: Do you have any further comments on P305?

Summary

Yes	No
17	13

Responses

Respondent	Response	Comments
Western Power Distribution	No	-
ScottishPower	No	-
IMServ (Europe)	Yes	In our Agent roles we would like to make the following observations: • We would like clarification on the volume and/or frequency of MPANs likely to be affected at any particular time. Will this be a large number of MPANs? The likely volume of activity will have a direct bearing on how our systems are updated. We do welcome the fact that these notifications will be via a data flow. • Section 7.1 – How should the HHDC respond to the notification from requirement 5.1 if the HHDC has not been appointed by the Supplier? How would this information be fed back to the DSO? • Further, how will change of agents be handled? For example if an agent is retrospectively appointed or de-appointed for an affected period how will they be notified and how will this data correction be handled? Would any retrospective action be required on the Agent(s) affected? • Why are Export MPANs being considered as they are unlikely to be impacted by a Disconnection event, surely? • Section 7.1 suggests estimating the half hourly data using the rules in BSCP502 section 4 – these rules will need amending since they instruct the HHDC to use Meter Advance where available, but this not appropriate in these circumstances since the Meter Advance will have also been affected by the disconnect event. Therefore for Import Metering Systems, sections 4.2.1.c and 4.2.1.e would not be used.

Respondent	Response	Comments
		Similarly, if Export Metering Systems are included, methods 4.2.2.d and 4.2.2.f would not been used. • Section 7.3 we assume that the HHDA validates that the DXXXX flow has been sent by the expected HHDC. Again, presumably if this was not the expected HHDC, an equivalent flow to the D0235 would be issued? What should the HHDA do when producing the DYYYY flow, exclude the MPAN(s) affected? • How should the HHDA react if they expect a DXXXX but don't receive one? • When processing the DYYYY flow, how will SVAA know it is complete since it does not contain data at the MPAN level but rather aggregated? • We assume that Reactive Data will not need the Data Correction applied, can this be clarified? • If a site is contributing to a Complex set up, with particular consideration to 3rd Party Private Networks, how will this be handled? Will the Data Correction be applied to all aspects? • Will DNOs have access to information such that they can exclude DSBR sites? • We are unclear how MPANs both at the boundary and within a Private Distribution Network will be handled. Is the intention that the DNO notifies the HHDC/DA of both the boundary MPAN and embedded MPANs and that the HHDC would estimate data for all MPANs? • How will partial intervals be handled as presumably the Demand Cessation will not be on strict interval boundaries? • Will the DWWWW flow contain times in G.M.T? • What is the expected timescales for the HHDC to produce the DXXXX flow? • Is the HHDC expected to ever produce a revised version of the DXXXX flow? • What is the expected timetable for the HHDA to produce the DYYYY, is this expected to follow the Settlement Timetable? Can this be justified

Respondent	Response	Comments
		against a one off report produced shortly after the Disconnection event? • Requirement D8 – again the requirements are unclear. If it is intended that the changes will be made in EAC/AA centrally rather than in Agents NHHDC systems individually, then the impact is minimised and would therefore be cheaper, more consistent, easier to test and more likely to be delivered in a timely manner. Is this the intention? • Requirement D7.4 states the DYYYY flow will be similar to the D0040, does this mean similar to the existing D0040 or the revised D0040 being proposed following P300 or another D0040 as yet unknown? Expecting agents systems to be able to support several new aggregated reporting processes at short notice, with no indication of volumes, costs or revenues, with no detrimental impact to current activities, is highly optimistic and could put Settlement at risk.
TMA Data Management Ltd	Yes	We would much rather the DXXXX and DYYYY flows contained 48 periods than a subset based only on the periods affected by the disconnection events. A similar process to the one used in D0275 flows during BST, using the Actual/Estimated indicator of C to fill the periods the Suppliers is not entitled to but still providing 48 periods within the flow. A new value for J0020 (Actual/Estimated indicator) could be created for the periods in a settlement day surrounding the disconnection event. The SVAA would then only load or take into account the periods flagged as A/E. This would lessen the development burden of P305 on all Party Agents. We would also prefer several modifications being raised in lieu of P305. P305 raises several changes impacting several aspects of the Imbalance pricing and balancing mechanisms. It would be easier to progress several modifications rather than risk having all changes blocked because one area of the modification is more problematic than others.
Drax Power Limited	Yes	With regards to the proposed single cash-out price, we have some concerns that this may lead to reductions in wholesale market liquidity particularly in extreme tight periods. This is because a single price does not create as strong a signal to trade

Respondent	Response	Comments
		relative to a dual cash-out price. Analysis to help determine the likely impact on wholesale market liquidity would be useful to enable better evaluation of P305. A better understanding of the distributional impacts of implementing a single price will be particularly welcome. Generally, the Workgroup has been hindered in its deliberations by the lack of available data with which to assess the likely impact of the various P305 solutions. The Workgroup will need to consider in detail the impacts suggested by Elexon's historic analysis to allow a thorough evaluation of the potential P305 options.
GDF SUEZ UK-Turkey	No	-
RWE Supply and Trading GmbH	No	-
SmartestEnergy	Yes	The document states that in the interests of simplicity the working group concluded to use Market Index Data to set the imbalance price when the NIV is zero. It would appear, however, that this is not a cheap option to maintain. How about just using the previous half hour's value. The document states the following: "Workgroup members considered whether, if a volume for Voltage Reduction events could not be calculated, it should be included under P305. It was also questioned whether Demand Disconnection and Voltage Reduction events should be treated equally, as a majority of consumers will never notice if they are affected by a Voltage Reduction event but would notice a Demand Disconnection event. One member felt it may be wrong to develop and introduce a complex and likely expensive process for an event that has hardly any impact. Such issues can be considered as part of an Issue focussed specifically on Voltage Reduction. At this stage, P305 only enables the inclusion of Voltage Reduction estimates in the 'top-down' estimate for use in the imbalance price calculation, and until a process for producing Voltage Reduction estimates is implemented they are in effect not counted as part of the 'bottom-up' calculation to adjust participants' imbalance positions." If the Issue Group agrees with the points made above then Voltage reduction will have been

Respondent	Response	Comments
		included in the top-down calculation unnecessarily.
Flow Energy	No	-
InterGen UK Ltd.	No	-
National Grid	No	-
DONG Energy	Yes	Further to changes currently under discussion, DONG Energy would like to highlight that a shorter gate closure time is expected to have positive impacts on forecast errors for generation from variable fuel sources as well as demand and therefore decrease imbalances. DONG Energy believes that this aspect should also be considered when creating a solution that better facilitates the applicable BSC objectives.
Good Energy	Yes	Under the alternative 'static' LoLP function under consideration LoLP is determined from a predetermined relationship between LoLP and de-rated system margin. At present the intention is that the forecast de-rated margin would be published on BMRS and parties would then need to apply for themselves the current formula to convert the forecast margin to an indicative LoLP. We would prefer the indicative LoLP to be published on BMRS in addition to the forecast de-rated margin on which it was based so it can be accessed by all parties simply and unambiguously from a common source whilst simultaneously providing transparency regarding the underlying data.
Centrica	No	-
RenewableUK	No	-
Electricity North West	Yes	Under D5 there is a reference to using SMRS to send the new Dataflow. The original intent of SMRS was to identify the Data Aggregators and Data Collectors of the disconnected MPANs, so that the relevant MPAN data could be provided to them via an Excel spreadsheet. We are unable to understand how this revised process will work in practice as the SMRS system is by definition a registration system and as such would hold effective from/to dates but not time of day. This would result in a change to the SMRS system to accommodate this granular level of data, together with internal systems in order to update the SMRS system. It's worth noting that with the advent of centralised registration what impact this would have in the

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		future (circa. 2017-18) as it would be difficult to put in place a new process with new Dataflows that may have a short shelf life.
VPI Immingham	Yes	We wish to see the cash out reforms implemented sooner rather than later. With a change expected for Winter 14/15, which in the end was rejected by the Authority, implementing a solution for Winter 15/16 is imperative.
UK Power Reserve Ltd	Yes	UK Power Reserve would like to fully endorse the implementation of P305 as a dearly needed reform of the energy market and that we are of the belief that P305 will lead to significant improvements in the UK energy market.
Green Frog Power	Yes	Green Frog Power strongly supports the implementation of all elements of cash-out reform. However, we believe that reducing the PAR volumes and moving to a single price are market priorities that should be implemented as soon as possible. We would therefore propose that Ofgem approve P316, at the same time requesting that National Grid (NG) press on with the remaining elements of P305.
Vattenfall	No	-
Eggborough Power	Yes	Eggborough Power has responded to the consultations on P316 and P305 on this one form. This will save repetition as it would appear that Ofgem can either sign off one or other of the modifications as they are in direct conflict. Ofgem will therefore have to consider which of the two modifications it prefers. Eggborough Power has significant concerns over elements of the P305 solution. We feel that the RSP, being based on a view of LLOP, is not going to provide parties with any form of information to which they can respond. There could be significant changes in cash-out without parties being able to go to the market to hedge that risk. The calculation of the voltage reduction/power cut demand changes is also not very robust. We therefore favour P316 over P305. It may be possible to come up with more robust solution for some of the elements of P305. It would therefore seem logical to implement P316 and then for Ofgem to ask National Grid (NG) to raise new modifications to implement the additional elements of Ofgem's SCR proposals, allowing the market to

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		develop signals that are robust, predictable and given in a manner such that parties can rationally respond.
Haven Power Limited	Yes	With regards to the proposed single cash-out price, we have some concerns that this may lead to reductions in wholesale market liquidity particularly in extreme tight periods. This is because a single price does not create as strong a signal to trade relative to a dual cash-out price. Generally, the Workgroup has been hindered in its deliberations by the lack of available data with which to assess the likely impact of the various P305 solutions. The Workgroup will need to consider in detail the impacts suggested by Elexon's historic analysis to allow a thorough evaluation of the potential P305 options. We are also concerned with the groupings used in the analysis from Elexon. In Elexon's analysis our party has been labelled as an 'Independent Thermal' instead of 'Independent Supplier'. It would also be useful to divide the costs calculated by Elexon for each individual party by their total IO14 volumes.
SSE plc	Yes	Please not that SSE LDSO and Supply Agency comments are limited to impact assessment comments only. Both parts of SSE are neutral to all others aspects of the proposal. It may be necessary within flagging rules to ensure that the SO flags a Demand Control action as a System Action in the event that Demand Control is instructed whilst feasible offers exist within the market but are not taken, where those offers are priced below VoLL. We would hope that this is an unlikely scenario, but were it to happen then short Parties ought not to be exposed to cash-out at VoLL in the event that the SO has simply failed to utilise all economic options available to it.
First Utility Limited	Yes	The analysis presented to the workgroup at its last meeting was of little use to the Workgroup in formulating any views. Subsequently, analysis has been produced and circulated as part of the consultation process. This analysis does not answer or address some of the key issues facing the workgroup and BSC participants: First issue: the impact of the modification on the competitive dynamics of the market. The

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		distributional impacts are quoted in £ and subdivided into broad groups. What is important to suppliers is the £/MWh impact on their cost base and hence their ability to compete. In addition the independent supplier group is extremely broad incorporating players from many TWh of I&C to a few hundred MWh of domestic. It is not possible to determine from the presented data the impact on individual user types and we expect the impact on them to vary significantly due to the wide range of intra-day delivery profiles within this broad category. Whilst the underlying data may be available, smaller players do not have the resources to analyse this in detail to fully understand the implications for them. Second issue: the modification is intended to change behaviours by increasing price signals at times of scarcity. To confirm this is happening as intended a graph showing the change in price v plant margin would be useful. It should be noted that throughout the progress of this modification, data and analysis has been consistently provided only a few days before and on at least one occasion the day before the workgroup was due to meet, leaving workgroup members with insufficient time to analyse and reflect on what the data was showing. An example of this is that the questions for this consultation were determined and the consultation issued before data that had been requested was published. All the analysis has been historical and covers periods where the market has been predominantly over-supplied with only a few very isolated periods of scarcity. The modification is intended to address an entirely different scenario with plant scarcity. The validity of the analysis performed does not represent the reality, nor necessarily give a good indication of likely impact. Third issue: supplier margins are small: sudden changes in costs could materially erode supplier margins leading to further unintended consequences for the market as a whole and a knock on effect in consumer prices. It would be a detrimental step for competition if suppliers were to fail as a result of the adverse distributional impact on risk profile at cashout this could introduce for different supplier types. Cummulative impact of other related industry changes:

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		This modification might be better than the "do nothing" option, but has highlighted other issues that can be solved at the same time. This would be appropriate as efficient and effective use of BSC time. The vendors of products that allow suppliers to manage the additional risks presented by this modification may have perverse incentives not to actively promote such products. The more that parties are unable to hedge their exposure, the larger the RCRC pot will become. This will then be redistributed to all market participants including those who did not promote risk management products. Non-vertically-integrated players in the market, or those with exposures that rely on market products to be managed, need to be reassured these products will be available at appropriate times in order to manage their risks. We see risk that such products will reduce in availability. If significant uncertainties exist in the market regarding the value of power, it can be expected that generators who provide the primary liquidity will leave their decision on the sale of any spare capacity until they are very confident they will not require it for their own purposes. Thus liquidity at times of scarcity can be pushed into very small time slots just before gate closure. During the last periods of significant scarcity in the period 2005 - 2008 liquidity in the prompt market became a major issue to market participants. Previously liquid markets dried up with very little volume trading and with huge price spreads of circa £700- 1300/MWh. Over the years Ofgem have highlighted the lack of forward trading liquidity as a major issue and a satisfactory level of liquidity has still not been achieved to date. We are therefore very concerned that the products required to manage the price volatility being presented by this change may not be available on acceptable terms or timescales to allow parties to manage their risks and for competition to continue to develop. The price distribution at cashout has a direct correlation to the price distribution in the intra-day, day-ahead and forward markets, so we see changes at cashout having a direct impact on the entire wholesale market.

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		The ability of parties to manage imbalance exposure is dependant upon their ability to accurately forecast both volume and price. Smaller parties may have difficulty in forecasting price as it is now dependent upon plant availability, wind, solar and interconnectors; issues that typically smaller participants do not have the critical mass of expertise to manage and deal with. In addition, given their smaller volumes, transaction costs of running complex hedging strategies are not viable. Ideally simplification of the price formulation is a prerequisite for smaller players. Thus setting an element of price such as LOLP 24 hours ahead is one small step to achieve this.
E.ON	Yes	While we supported the objectives of the Electricity Balancing SCR, notwithstanding the economic theory we fear that in reality there is very little scope for parties to improve balancing efficiency; furthermore that P305 will not have a positive impact upon investment decisions. Some useful analysis has been performed through the P305 Workgroup e.g. in splitting out potential imbalance cost and rcrc impacts of the proposals, and exploring LOLP. However ultimately it seems that P305 would introduce complexity for little if any clear benefit but at increased risks and definite costs centrally, to parties, and ultimately consumers. We note that the allegedly positive benefits that the EBSCR policy analysis/decisions originally suggested might arise by 2030 were at the time projected to be small, and further reduced in the case of a CM introduction. Now that the CM is in place, along with further measures like DSBR and SBR, to introduce further changes that will undoubtedly increase unmanageable risks, for unproven benefits in the short or longer term, would seem unwise. Holding back on this proposal, or at least some further work, avoiding any rushed decision, might help to ensure that any change decided upon is robust in itself, while more time would also allow a better evaluation of the effects of other developments. (Regarding the process followed for this SCR mod, it has been rather rushed in order to adhere to a timetable that was set before the Workgroup knew how much work it would entail. Background work from Elexon/National Grid has not been provided until immediately before or only at some

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		Workgroups, with some groups also very close together enabling discussions to continue but little time for members to evaluate information received before the group has had to move on. For industry consultation, while an extra week was ostensibly allowed for Christmas/New Year and the close extended from Fri 9th to Wed 14th Jan at the request of the Workgroup, we were disappointed that in practice the consultation was not issued until Tue 16th Dec, the analysis Fri 19th. The Workgroup had specifically requested and been assured that the analysis would accompany the consultation, though with such a large amount of data it is hardly surprising that more time was required to produce some. In reality thus only the usual 15 working days have been available for parties to consider what was provided; with most colleagues on leave for several of those 'working' days, unfortunately parties have actually had less time than usual to attempt to assess complex proposals. Additionally with the lack of data for, or simulating, Demand Control actions being taken and priced in at VoLL at either rate proposed, and RSP only featuring at the lower rate proposed, there have been gaps in the data provided: 5 of the 20 scenarios requested, missing. It is regrettable that nearing the end of the EBSCR process, with little time for industry to assess the potential impact of the actual BSC proposals, further work is still required to obtain a clearer picture of the potential impact on parties. If these gaps could be filled in time for the Report Phase consultation, that would be helpful in at least giving parties a chance to evaluate the potential impact of the proposed 2018 changes if they are retained in the Proposal or any Alternative. While there was some debate over the merits of historic analysis, the fact that it has exposed, for example, some RSP effects 'contrary to expectation…likely to be a consequence of additional non-BM STOR actions and revised Buy Price Adjusters…' (Historic Analysis p16) has been useful. Without further analysis there is a risk that other unexpected effects/unintended consequences might not be exposed, compromising the ability for a well-informed decision to be made).
Stark Software International Ltd	Yes	We are unhappy and the use of Agents being required to provide several simultaneous additional services that are bolted on with limited communication and no financial compensation at an

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		already extremely busy time. Ie Smart, P272, P300, P305 and DSBR. It is quite possible there are other initiatives planned that again will require new Agent inputs and it would be helpful if these are made clear in advance. SAF (Supplier Agents Forum) was an ideal oppurtunity for this sort of thing and is sorely missed.
Utilita	No	-
Cornwall Energy	No	-
EDF Energy	Yes	We have some concerns that the lack of a bid-offer spread in cashout prices in a single cashout price regime could reduce liquidity on the prompt market. By definition, one leg of every trade executed will have been done at a negative mark to cashout (including those executed at the eventual cashout price, once one takes exchange fees into account). Any wholesale trade will therefore have an element of lost opportunity in its price stack, compared with trade relative to a dual-price cashout. Assuming that liquidity still exists in the prompt, the removal of the market-based reverse price means that executed trades would not directly affect the future cashout price. When changes occur to the supply or demand stacks, prices would move instantly to the new expected value of cashout. This could have the effect of increasing volatility, and lead to wider bid-offer spreads as delivery approaches. With a single imbalance price, it is easier to construct conventional bilateral contracts for difference using the imbalance price as a reference, rather than trade physically. There is a possibility that participants may leave a higher proportion of balancing to the System Operator, and settle more volume between themselves bilaterally non-physically. If the System Operator is able to balance the system collectively more efficiently than participants individually, this could be an efficient outcome. Single price could increase opportunities for self-balancing after gate closure, either by consumers and other users of the system who are not captured by the Grid Code, or by industry participants in contravention of the Grid Code. We expect NGET to monitor such behaviour and manage it appropriately

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		if it is or becomes a material issue.
Co-Operative Energy	No	-

Key points

- **Energy UK supports the reforms to cashout**
- **Support the principle of moving to a single, more marginal cash out price for Winter 2015/15, regardless of the other components**
- **Concerns regarding the LOLP and Demand Control function and wish to see a robust solution implemented**

Efficient balancing is a fundamental feature of a functioning electricity market and therefore Energy UK supports reform of the existing cashout arrangements. The need for the right incentives to balance is particularly acute with the tightening capacity margins. At the same time, the energy sector is in a period of significant change with EMR, European integration and other regulatory changes. The various policy and regulatory developments are interlinked and therefore adequate foresight and certainty about forthcoming changes is important to enable investment decisions and system changes to be made.

In this context, Energy UK members, drawn from all types of market participant, support the principles of P316, to move to a single and more marginal cashout price in Winter 2015. There is, however, a diversity of views on specific PAR values and we believe that these must be fully assessed by the Working Group. P316, or an alternative, would also need to be aligned with the single, more marginal cashout elements of P305.

Our members have concerns about the progress of P305 given the lack of confidence in the robustness of the Loss of Load Probability methodology as it stands and given the amount of work that is still required. The proposals on demand control volume allocations and how they feed into cashout prices also require further work. It is essential that a robust solution that is fit for purpose is implemented and therefore we believe that considerable further work is required and that a decision should not be rushed into. In addition, implementation on these parts of the package will require significant lead time because of the potential volatility impact which industry participants will need to understand and simulate in order that risk can be managed.

Energy UK therefore proposes that the LOLP calculation and demand control volume allocations becomes longer term goals and considered separately from the rest of the cashout package. We believe this to be a pragmatic and sensible approach which will ensure that a major part of Ofgem's SCR objectives are achieved whilst also providing certainty to industry with a sufficient lead time.

As raised by our members in their previous consultation responses, balancing behaviour change resulting from sharpened cashout prices will only be possible if parties have the ability to mitigate the risk. Market participants will therefore need to be able to access and trade the products to enable them to manage the risks associated with more marginal cashout prices. Implementation of single, more marginal cashout by November 2015 should provide a sufficient lead time for those products to be developed provided that a decision in made by the Authority in April 2015. A minimum of six months is required as an implementation lead time, particularly for suppliers.

I hope this letter has been helpful in setting out the areas of agreement across the industry and will complement the more detailed individual responses received. This letter will be copied to Ofgem so they are also aware of our position.