Assessment Procedure Consultation

P305 'Electricity Balancing Significant Code Review Developments'

P305 proposes to progress and implement the conclusions to the Electricity Balancing Significant Code Review, which will put in place a single, marginal imbalance price, introduce Reserve Scarcity Pricing and introduce pricing for Demand Control actions.

This Assessment Procedure Consultation for P305 closes:

5pm on **Wednesday 14 January 2015**

The Workgroup may not be able to consider late responses.

Please note that P316 'Introduction of a single marginal cash-out price' is related to P305 and is being consulted upon at the same time.

The P305 Workgroup has not made an initial recommendation on P305

This Modification is expected to impact:

- BSC Trading Parties
- Distribution System Operators (DSOs)
- Data Aggregators (HHDAs/NHHDAs)
- Data Collectors (HHDCs/NHHDCs)
- The Transmission Company
- The Balancing Mechanism Reporting Agent (BMRA)
- The Central Data Collection Agent (CDCA)
- The Settlement Administration Agent (SAA)
- The Supplier Volume Allocation Agent (SVAA)
- ELEXON

Consequential changes will be required to:

- The Grid Code
- The Data Transfer Catalogue (DTC)

ELEXON

What stage is this document in the process?

01 Initial Written Assessment

02 Definition Procedure

03 Assessment Procedure

04 Report Phase

Contents

About This Document

The purpose of this P305 Assessment Procedure Consultation is to invite BSC Parties and other interested parties to provide their views on the merits of P305. The P305 Workgroup will then discuss the consultation responses, before making a recommendation to the BSC Panel at its meeting on 12 February 2015 on whether or not to approve P305.

There are three parts to this document:

- This is the main document. It provides details of the solution, impacts, costs, benefits/drawbacks and proposed implementation approach. It also summarises the Workgroup's key views on the areas set by the Panel in its Terms of Reference, and contains details of the Workgroup's membership and full Terms of Reference.
- Attachment A contains the detailed analysis and assessment undertaken by the P305 Workgroup. It also provides a summary of Ofgem's evidence base developed during the course of its Significant Code Review. ELEXON's historical analysis will be published separately shortly after this consultation being issued.
- Attachment B contains the specific questions on which the Workgroup seeks your views. Please use this form to provide your response to these questions, and to record any further views or comments you wish the Workgroup to consider.

Any questions?

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1 Summary

Why Change?

P305 has been raised by National Grid to progress the conclusions to Ofgem's Electricity Balancing Significant Code Review (SCR) (EBSCR), which looked at imbalance prices. In particular, Ofgem expressed concerns that imbalance prices are not creating the correct signals for the market to balance, which could undermine efficiency in electricity security of supply and balancing, unnecessarily increasing costs.

Solution

P305 proposes to:

- reduce the Price Average Reference (PAR) value to 50MWh and the Replacement PAR (RPAR) value to 1MWh upon implementation, and reduce the PAR value further to 1MWh on 1 November 2018;
- introduce a single imbalance price;
- improve the way Short Term Operating Reserve (STOR) actions are priced; and
- introduce pricing for Demand Control actions and a process for correcting participants' imbalance volumes following such an event.

The Workgroup is considering various areas of the solution for possible inclusion in a potential Alternative Modification. These areas concern how Loss of Load Probability (LoLP) values are calculated and the size of, and approach to, the PAR value reduction.

Impacts & Costs

P305 will directly impact Distribution System Operators (DSOs), Data Aggregators, Data Collectors, the Transmission Company and BSC Agents. P305 will indirectly impact BSC Trading Parties. The central systems implementation costs are approximately £625k.

P305 has been previously issued for industry Impact Assessment, but following further development of the P305 solution, further details of the implementation impacts of P305 on industry participants are sought, including costs and timescales.

Implementation

P305 is proposed for implementation on 5 November 2015 (November 2015 BSC Systems Release).

Recommendation

The Workgroup has not made an initial recommendation for P305.

2 Why Change?

What is imbalance pricing?

Imbalance pricing (also known as "cash-out") is a key part of the wholesale trading arrangements in Great Britain (GB).

The wholesale electricity market is set up such that BSC Parties enter into bilateral contracts with each other in order for generators to be able to sell the energy they produce to Suppliers to supply their customers. For any given half hour Settlement Period, Parties may trade with each other up to a point one hour beforehand, known as Gate Closure. Parties will aim to balance their position for a given Settlement Period at this time such that the amount of energy they generate or buy matches the amount of energy they consume or sell. However, there are circumstances where this does not happen, such as a generator experiencing an unexpected outage that does not allow them to generate the expected amount of energy, or a Supplier over- or under-estimating the amount of demand their customers actually use. This leaves the Party in a position of imbalance.

Following Gate Closure, National Grid, in its role as the National Electricity Transmission System Operator (NETSO) (referred to under the BSC as the Transmission Company), will assess the amount of planned generation and the amount of demand expected for the Settlement Period, and will take actions to balance the system such that the total amount generated matches the total amount consumed. It does this in the Balancing Mechanism (BM) by accepting Bids and Offers submitted by participants, usually generators, to increase or decrease the amount of energy they will produce (or consume) to ensure the system is balanced. It will also take actions outside the Balancing Mechanism, such as the use of STOR. It will do this up to and throughout the Settlement Period to ensure the system is balanced at all times.

Following the end of a Settlement Period, ELEXON will compare the amount of energy each Party contracted with its metered volumes for the Settlement Period, accounting for any balancing actions. Any surplus or shortfall that the Party has is paid for using the relevant imbalance price:

- If the Party is **short** (it consumed or sold more energy than it generated or bought) then it pays for its shortfall at the **System Buy Price** (SBP).
- If the Party is **long** (it generated or bought more energy than it consumed or sold) then it is paid for its surplus at the **System Sell Price** (SSP).

There are two methods for calculating the imbalance price:

- The **Main Price** is based on the Bids and Offers accepted by the Transmission Company for that Settlement Period.
- The **Reverse Price** is based on the market price of electricity for that Settlement Period.

Which method (Main or Reverse) is applied to which imbalance price (SBP or SSP) is determined by whether the system as a whole was long (the Net Imbalance Volume (NIV) was zero or negative) or short (the NIV was positive) in that Settlement Period:

- If the system is long, the SSP will be the Main Price and the SBP will be the Reverse Price.
- If the system is short, the SBP will be the Main Price and the SSP will be the Reverse Price.

What are Bids and Offers?

Bids and Offers are submitted by Parties to the Transmission Company, proposing to increase or reduce generation or demand in exchange for payment. The Transmission Company will accept these as required to balance the system.

Bids are proposals to reduce generation or increase consumption.

Offers are proposals to increase generation or reduce consumption.

Imbalance Pricing Guidance Note

More detail on imbalance prices and how they are calculated can be found in our Imbalance Pricing Guidance Note.

As a result, the Main Price is applied to any Party whose imbalance contributed to the overall system imbalance, who will therefore face the costs of the Bids and Offers accepted to resolve that imbalance. Conversely, the Reverse Price is applied to any Party whose imbalance helped to reduce the overall system imbalance, who will therefore face a price that reflects what it would have incurred had it traded out its position ahead of time.

What is STOR?

National Grid will hold access to extra power in the form of either generation or demand reduction during certain periods of the day. This enables it to ensure that it can respond to scenarios such as actual demand being greater than forecast demand or unforeseen generation unavailability. These additional sources of power are referred to as 'Reserve'.

To help meet its reserve requirement, National Grid procures STOR by contracting for balancing services via a competitive tender process from a range of service providers, for example in the form of standby generation or demand reduction from parties that may or may not participate in the BM. This is a contracted Balancing Service whereby the provider is required to deliver a contracted level of energy when instructed by the Transmission Company, within pre-agreed parameters. The requirement for STOR varies depending on the time of year, week and day, and is a function of the system demand profile at that time.

STOR is contracted ahead of time, in some cases many months before it is actually used. Under STOR contracts, availability payments may be made to the balancing service provider in return for the unit being made available to National Grid. When STOR is called upon, the price National Grid pays for its use is the price agreed between it and the provider under the contract, referred to as the Utilisation Price. This may be noticeably different to than the price National Grid may have paid had it called upon a BM action, and therefore may not reflect the prevailing market prices at the time of use. It is this Utilisation Price that is used when STOR information is submitted into the imbalance price calculations. Availability costs are currently allocated to Settlement Periods via the Buy Price Adjuster (BPA) according to a weighted profile; this approach does not necessarily reflect tight margins or STOR usage.

What is Demand Control?

If National Grid is unable to call upon sufficient generation to meet the current demand, then it can call upon Demand Control under Grid Code Section OC6 'Demand Control', as a last resort emergency instruction, to manage the situation. This enables it to call upon DSOs to reduce demand in their areas, either through initiating Voltage Reduction and/or disconnecting consumers through Demand Disconnection. A DSO typically may be required to reduce demand in blocks of approximately 5% of its total demand, and is required to respond to National Grid's instruction within five minutes of it being issued. It is usually left to the DSO to determine how it achieves the instructed reduction, which will often be through a combination of Demand Disconnection and Voltage Reduction.

What is the Electricity Balancing Significant Code Review?

In August 2012, Ofgem launched its Electricity Balancing Significant Code Review to look at imbalance prices, in order to address long-standing concerns that it had raised in 2010 within its Project Discovery report. In particular, Ofgem expressed concerns that imbalance prices are not creating the correct signals for the market to balance, which could undermine efficiency in balancing and security of supply.

Ofgem published its Final Policy Decision on 15 May 2014. Its final decision document lays out its conclusions and builds on the extensive analysis and stakeholder engagement it has conducted during the EBSCR over the course of several years.

What is Ofgem's rationale for reform?

In its Final Policy Decision, Ofgem lays out its rationale for why reform of imbalance prices is needed. In it, it notes that the actions of the Transmission Company in balancing the system in real time is the basis for the calculation of imbalance prices, and considers that a number of factors currently dampen these prices:

- Prices are calculated using an average of the most expensive (to the Transmission Company) 500MWh of Bids or Offers taken to balance the system, rather than the most marginal action (the energy balancing action with the highest cost to the Transmission Company).
- Prices do not include the costs to consumers of involuntary Demand Disconnections and Voltage Reductions.
- The way reserve capacity is costed does not allow imbalance prices to rise to reflect tight margins (defined as the amount of surplus capacity available at any given time over the volume of expected demand at that time).

Additionally, the current dual imbalance price system creates unnecessary balancing costs, disadvantaging in particular smaller Parties.

Ofgem considers that the shortcomings with the current arrangements mean that the market does not sufficiently value flexibility (the ability to ramp generation or demand up or down quickly in response to changing market conditions). As a consequence, market participants have insufficient incentives to provide flexible capacity (such as flexible generation, demand response services and storage) to meet demand. Shortcomings may also make it more likely that Interconnectors export at times of system stress or import less than under more efficient arrangements. As the share of intermittent generation grows, flexibility will only become more important for efficiency in security of supply and balancing.

Ofgem believes that imbalance price arrangements and the government's planned Capacity Mechanism (CM) have distinct but complementary roles in seeking to ensure electricity security of supply. The CM is intended to address longer term capacity adequacy by providing capacity providers with a secure revenue stream for their investment. Reform of imbalance prices complements this by providing efficient signals of the value of flexibility, influencing the type of capacity coming forward. In addition, imbalance prices have the potential to reduce the cost of procuring capacity in the CM auction by allowing flexible capacity providers to recoup missing money from the wholesale market.

What is a Significant Code Review?

A Significant Code Review is an Authority-led review process on an area of work which the Authority considers:

- has a significant impact on the Authority's principal objective, statutory functions or relevant obligations imposed by European Union law; and in particular:
  - has significant impacts on consumers or competition; and/or
  - has significant impacts on the environment, security of supply or sustainable development; or
- creates significant cross code or cross licence issues.

Upon completion of a Significant Code Review, the Authority may direct the Transmission Company to raise one or more Modifications to progress the conclusions. Please see BSC Section F5 for more details.

Work under the EBSCR

The detailed and comprehensive analysis and evidence base arising from the EBSCR can be found on the EBSCR page of the Ofgem website. A full list of the relevant documents can be found in Appendix 3.

What is the issue?

Upon completion of an SCR, the Authority may, under BSC Section F5.3, issue a direction to the Transmission Company to raise an SCR Modification Proposal to progress the outcomes.

On 15 May 2014, Ofgem, as the Authority, issued such a direction to National Grid, as the Transmission Company, to raise two such Modifications to progress the conclusions of the EBSCR. P304 'Reduction in PAR from 500MWh to 250MWh' was raised to progress an initial, standalone change to the PAR value ahead of the winter 2014/15 season, but has since been rejected. P305 'Electricity Balancing Significant Code Review Developments' has been raised to progress the EBSCR's full package of proposed changes ahead of the winter 2015/16 season.

Proposed solution

P305 proposes to progress the reforms outlined by the Authority arising from the EBSCR. These reforms have been split into four areas:

- reductions in the PAR value;
- moving to a single imbalance price;
- the introduction of Reserve Scarcity Pricing; and
- the introduction of pricing for Demand Control actions.

The full detail on each area of reform and the rationale behind them can be found in Ofgem's Final Policy Decision. A summary diagram of the changes proposed by P305 can be found in Appendix 1, and the detailed solution requirements for each area can be found in Attachment A.

Solution requirements

The detailed solution requirements for the P305 Proposed Modification can be found in Attachment A.

Reductions in the PAR value

P305 proposes to reduce the PAR value from its current level of 500MWh to 50MWh upon implementation, before reducing further to 1MWh on 1 November 2018 ahead of the winter 2018/19 season.

P305 will also reduce the RPAR value from its current level of 100MWh to 1MWh upon implementation.

These changes will make the imbalance price more marginal, as eventually only the most expensive 1MWh of actions would be used to set the price.

What is PAR and RPAR?

The **PAR** volume is a set volume of the most expensive balancing actions remaining at the end of the Main Price calculations, and is currently 500MWh. The volume-weighted average of these actions is used to produce the Main Price. This is referred to as PAR Tagging.

The **RPAR** volume is a set volume of the most expensive priced actions remaining at the end of the Main Price calculations, and is currently 100MWh. The volume-weighted average of these actions, known as the Replacement Price, is used to provide a price for any remaining unpriced actions prior to PAR Tagging.

Moving to a single imbalance price

A single imbalance price will be applied in place of the dual imbalance prices currently in use. Both the SBP and SSP will be retained, but they will be set equal to each other, with that single price being calculated using the Main Price methodology.

Market Index Data will be retained and the Market Price would be used to set the imbalance price in any Settlement Period where the NIV was zero. Market Index Data would be published for each Settlement Period on the Balancing Mechanism Reporting Service (BMRS).

Introduction of Reserve Scarcity Pricing

Both accepted BM and non-BM STOR actions will be included in imbalance prices as individual actions, with a price which is the greater of the Utilisation Price for that action or a Reserve Scarcity Price (RSP). The RSP function will be based on the prevailing scarcity of the system, and would be calculated as the product of two new values:

- the LoLP, which will be calculated by the Transmission Company at Gate Closure for a given Settlement Period; and
- the Value of Lost Load (VoLL), as outlined below.

STOR availability costs would be removed from the Buy Price Adjustment (BPA) calculation.

The LoLP will be calculated by the Transmission Company for each Settlement Period, using the method described in Attachment A. Values would be calculated at the following times:

- An indicative value would be calculated at 12:00 each day for all Settlement Periods up to the end of the next Operational Day[1].
- An indicative value would be calculated for each individual Settlement Period at eight, four and two hours prior to the start of the Settlement Period (seven, three and one hour(s) prior to Gate Closure).
- The final value would be calculated for each Settlement Period at Gate Closure for that Settlement Period.

All indicative and final values of LoLP would be published on the BMRS as soon as possible following receipt. If no value can be calculated for a given calculation point, the value will default to the most recently calculated indicative value for that Settlement Period at that point in time, or if no such value is available then to null. The final value would be used in the calculation of the RSP for that Settlement Period.

Introduction of pricing for Demand Control actions

The volumes of any disconnections and voltage reduction instructed by the Transmission Company ("System Operator (SO) instructed Demand Control actions") would be included in the imbalance price calculation at a price referred to as the VoLL price. This price would be set to £3,000/MWh upon implementation, rising to £6,000/MWh on 1 November 2018 ahead of the winter 2018/19 season. This value would be hard-wired into the Code, and could be amended at any time via a Modification.

A VoLL review process will be introduced into the BSC to allow the Panel to initiate a review of the value at any time or upon the request of the Authority. The detailed review process will be developed and agreed by the Panel, but consultation with the industry will be mandatory before a final conclusion is reached. Should the Panel believe a change to the VoLL value should be progressed following a review, it will have the ability to raise a corresponding Modification. This process would not prevent any other participant eligible to do so from raising their own Modification at any time to propose a revised VoLL value.

An estimate of the total volume of Demand Control actions would be calculated using a 'top-down' approach for use in the imbalance price calculations (including the BMRS indicative prices), based on the volumes instructed of DSOs by the Transmission Company. These actions will be priced at the VoLL price, and will be subject to all the usual tagging and flagging rules within the imbalance price calculations (including being flagged as system management actions).

A more accurate 'bottom-up' approach to calculating the total Demand Disconnection volume will be carried out in time for the Initial Settlement Run (SF), which will entail identifying the individual consumers affected and estimating what they would have consumed had the disconnection not taken place. Participants' imbalance positions would be adjusted for Demand Disconnection actions. At this stage, a method for adjusting

Demand Control volume estimation process requirements

The detailed solution requirements for the Demand Control volume estimation processes can be found in Attachment A

The 'top-down' approach is covered by Requirements D2-D4.

The 'bottom-up' approach is covered by Requirements D5-D9.

[1] Operational Day is defined under the Grid Code as the period starting at 05:00 on one day and ending at 05:00 on the following day.

volumes in response to Voltage Reduction actions has not been developed, and the P305 Workgroup has agreed that this will be progressed separately to P305 through a BSC Issue.

Legal text

Due to the complexity of the changes to the BSC to deliver P305, the Workgroup has not prepared the draft changes for this Assessment Procedure Consultation. The Workgroup will develop these in parallel with this consultation, and these will be issued for industry comment as part of the Panel's Report Phase Consultation.

A significant number of Code Subsidiary Documents (CSDs), Configurable Items and Core Industry Documents will also require changes to implement P305, and the list of these documents can be found in Section 4. The changes to these documents will be prepared and consulted upon separately.

Potential alternative solution

At this stage, the P305 Workgroup is considering several potential options for an alternative solution. The areas that are being considered under a potential alternative solution relate to different PAR values and an alternative calculation for LoLP values. The Workgroup has not expressed a clear preference for any particular options over any others, although a majority of members support the use of the alternative LoLP calculation method when compared to the proposed calculation. The Workgroup's full discussions on these areas can be found in Sections 6 and 7.

Alternative PAR values

The Workgroup is considering the following alternative PAR values in addition to that put forward by the Proposer:

- 250MWh upon implementation then 100MWh 12 months later;
- 100MWh upon implementation with no further change;
- 50MWh upon implementation with no further change; and
- 1MWh upon implementation with no further change.

In all cases, the RPAR value would continue be set to 1MWh upon implementation.

Alternative LoLP function

The Workgroup has developed an alternative LoLP function which would use the values produced by the Proposer's proposed function detailed in Attachment A to derive a static function relating the de-rated margin in a given Settlement Period to a LoLP value.

Under this option, a function will be derived for given periods of time (such as for the summer and winter halves of each year) at an agreed lead time in advance of that period based on when the necessary input data becomes available. This function would be derived using historical data from the previous two equivalent periods (so a function for a given winter period would be based on historic data from the preceding two winter periods). The method for this is described in Attachment A.

A LoLP value for a given Settlement Period would be determined based on the forecasted de-rated margin at a given lead time ahead of the Settlement Period, as described in Attachment A. This LoLP value would then be used to derive an RSP as per the proposed solution.

At this time, the Workgroup is considering whether the LoLP value for a given Settlement Period should be determined using the forecasted de-rated margin:

- one hour ahead of the relevant Settlement Period (i.e. at Gate Closure for the Settlement Period);
- two hours ahead of the Settlement Period (one hour ahead of Gate Closure);
- four hours ahead of the Settlement Period (three hours ahead of Gate Closure); or
- 24 hours ahead of the Settlement Period.

In any event, the LoLP value would be published on the BMRS as soon as possible following determination. No indicative LoLP values will be produced. Instead, the forecasted de-rated margin would also be published on the BMRS which participants could use to consider what the LoLP value may be prior to the confirmed calculation point.

Summary of solution options

The solution options that the Workgroup is considering that might potentially comprise a P305 Alternative Modification are:

P305 Solution Options	
PAR values	LoLP functions
• 50MWh upon implementation then 1MWh on 1 November 2018 (as under the Proposed Modification) • 250MWh upon implementation then 100MWh 12 months later • 100MWh upon implementation with no further change • 50MWh upon implementation with no further change • 1MWh upon implementation with no further change	• 'Dynamic' function with LoLP calculated at Gate Closure (as under the Proposed Modification) • Alternative 'static' function with LoLP calculated at Gate Closure • Alternative 'static' function with LoLP calculated two hours before the Settlement Period • Alternative 'static' function with LoLP calculated four hours before the Settlement Period • Alternative 'static' function with LoLP calculated 24 hours before the Settlement Period

It is anticipated that any Alternative Modification would consist of one item from each list, with all other aspects unchanged from the Proposed Modification. The Workgroup invites the views of industry participants to assist it in determining the composition of a potential P305 Alternative Modification.

Assessment Consultation Questions
Do you have a preferred solution option that you believe should be progressed as an Alternative Modification? *Please provide your rationale with reference to the Proposed Modification and the Applicable BSC Objectives.*
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? *Please provide your rationale and, if 'Yes', please provide full details of your Alternative Modification(s) and your rationale as to why it/they better facilitate the Applicable BSC Objectives compared to the Proposed Modification.*
The Workgroup invites you to give your views using the response form in Attachment B

Interaction with P304, P314 and P316

Interaction with P304 and P314

P304 was raised by National Grid alongside P305 to propose a reduction in the PAR value to 250MWh ahead of the winter 2014/15 season. This was intended to provide an early step-change in the PAR value ahead of the full EBSCR reforms being implemented, to assist participants in transitioning to the new arrangements. P314 'Reduction in PAR from 500MWh to 350MWh' was raised by First Utility during the progression of P304 to propose an alternative reduced PAR value of 350MWh.

It was felt that reducing the PAR value without implementing a single price could have a detrimental on some participants and that the change was proposed to come in too quickly for Parties to be able to respond to the signal. Both Modifications have since been rejected by the Authority as it was felt that the effects of the proposed changes were finely balanced and would be modest at most.

You can find more information on each Modification in their respective Final Modification Reports and the accompanying Authority Decision Letter, available on the P304 and P314 pages of our website.

Interaction with P316

P316 'Introduction of a single marginal cash-out price' has been raised by RWE Supply and Trading to propose that only the single marginal price elements of P305 are progressed. P316 proposes the same move to a single price as P305, but is proposing that both the PAR and the RPAR values are reduced to 1MWh upon implementation. The Proposer considers that P316 will increase the certainty of a single marginal price being implemented in a timely manner and ahead of winter 2015/16, and would potentially allow for the other areas proposed by P305 to be implemented at a later date.

P316 is being progressed in parallel with P305, and you can find the full details and discussions in relation to P316 in the P316 Assessment Procedure Consultation, which has been issued alongside this P305 Assessment Procedure Consultation.

Estimated central implementation costs of P305

The total central implementation costs for P305 are approximately **£625k** to make the necessary changes to the BSC central systems and the BMRS website.

Changes are needed to the Settlement Administration Agent (SAA) and the Balancing Mechanism Reporting Agent (BMRA) systems to move to a single price and to include STOR and Demand Control actions into the imbalance price calculations. The SAA, Supplier Volume Allocation Agent (SVAA) and Central Data Collection Agent (CDCA) systems will also need amending to introduce the Demand Control volume estimation processes.

The BMRS website will be updated to publish all Indicative and Final LoLP values, all individual STOR actions and any Demand Control notifications issued by the Transmission Company.

Indicative industry implementation costs of P305

DSOs have indicated that they would incur costs of up to £20k to implement the 'bottom-up' process for calculating the total Demand Disconnection volume, while **Supplier Agents** have indicated "medium to high" costs. These participants would need to amend their software to send and/or receive the new Data Transfer Catalogue (DTC) data flows that will be created by P305 and will need to put in place the new processes for the Demand Disconnection volume calculation process.

BSC Trading Parties have indicated costs ranging from minimal up to around £150k to implement P305, with some indicating on-going costs of up to £100k per annum. These participants will be predominantly impacted by the changes in imbalance charges and exposure, which will impact the levels of Credit Cover they consider they may need to lodge as well as their trading strategies. They may also need to amend their systems to receive any new data published on the BMRS.

The full responses made by participants to the industry impact assessment can be found on the P305 page of our website. As part of this Assessment Procedure Consultation, we seek more detail on the potential impacts and costs associated with implementing P305. In particular, we seek updated responses from DSOs and Supplier Agents, as the Demand Disconnection volume calculation process has been amended since the original impact assessment was issued; you can find the revised solution requirements in Attachment A.

Assessment Consultation Questions
Will P305 impact your organisation? *If 'Yes', please provide a description of the impact(s) and any activities which you will need to undertake between the Authority's approval of P305 and the P305 Implementation Date (including any necessary changes to your systems, documents and processes). Where applicable, please state any difference in impacts between the Workgroup's proposed solutions.*

Implementation impacts and costs

This Section only considers the implementation impacts and costs of P305.

The wider impacts of P305 have been considered as part of the Workgroup's analysis in Attachment A and in Ofgem's Final Policy Decision.

Assessment Consultation Questions
Will your organisation incur any costs in implementing P305? *If 'Yes', please provide details of these costs, how they arise and whether they are one-off or on-going costs. Please also state whether it makes any difference to these costs whether P305 is implemented as part of or outside of a normal BSC Systems Release. Where applicable, please state any difference in costs between the Workgroup's proposed solutions.*
The Workgroup invites you to give your views using the response form in Attachment B

P305 impacts

Impact on BSC Parties and Party Agents	
Party/Party Agent	Impact
BSC Trading Parties	BSC Trading Parties will be indirectly impacted by the reforms, as Ofgem's reform package will introduce a more marginal single imbalance price.
DSOs	DSOs, Data Aggregators and Data Collectors will be involved in the 'bottom-up' process for calculating the total Demand Disconnection volume.
Data Aggregators	
Data Collectors	

Impact on Transmission Company
The Transmission Company will be required to implement a LoLP Calculation Methodology, which would be contained in a new Code Subsidiary Document. It would then need to calculate the LoLP for each Settlement Period at Gate Closure for that Settlement Period. The Transmission Company will also be required to publish indicative LoLP figures ahead of Gate Closure. The Transmission Company will notify the BMRA of the start and end of any Demand Control events, and provide any data required for calculating the volume impacted by the event.

Impact on BSCCo	
Area of ELEXON	Impact
Imbalance price arrangements	Processes, reports and documents will need to be amended to account for the changes introduced by P305.
BSC Audit	Amendments may be required for the new processes introduced by P305, in particular the 'bottom-up' process for calculating the total Demand Disconnection volume.
EMRS	The EMRS will be required to provide information to the SAA as part of the 'bottom-up' process for calculating the total Demand Disconnection volume. This will require corresponding changes to the Electricity Market Reform (EMR) arrangements.

Impact on BSC Systems and processes	
BSC System/Process	Impact
BMRA	Changes will be required to reflect the changes to the imbalance price calculations. The BMRA will also be required to publish LoLP values and Demand Control event notifications on the BMRS.
SAA	Changes will be required to reflect the changes to the imbalance price calculations. The SAA will also be impacted by the 'bottom-up' process for calculating the total Demand Disconnection volume.
CDCA	The CDCA and the SVAA will be impacted by the 'bottom-up' process for calculating the total Demand Disconnection volume.
SVAA	

Impact on Code	
Code Section	Impact
Section F	Changes would be required to implement this Modification. These will be developed by the Workgroup and consulted upon as part of the Report Phase Consultation.
Section Q	
Section R	
Section S	
Section S Annex S-2	
Section T	
Section V	
Section X Annex X-1	
Section X Annex X-2	

Impact on Code Subsidiary Documents	
CSD	Impact
BSCP01	Changes may be required as a result of this Modification.
BSCP03	
BSCP18	
BSCP40/BSCPXXX	Changes will be required to detail the VoLL review process; it is currently anticipated that this process would be captured either in BSCP40 or in a new BSCP.
BSCP502	Changes will be required to detail the 'bottom-up' process for calculating the total Demand Disconnection volume; it is to be confirmed which of these documents will need amending to reflect this.
BSCP503	
BSCP504	
BSCP505	
BSCP508	

Impact on Code Subsidiary Documents	
CSD	Impact
BMRA Service Description	Changes will be required to reflect changes to existing processes and/or the introduction of new processes for the relevant BSC Agents.
CDCA Service Description	
SAA Service Description	
SVAA Service Description	
BMRA User Requirement Specification	
CDCA User Requirement Specification	
SAA User Requirement Specification	
SVAA User Requirement Specification	
NETA Interface Definition and Design	Changes will be required to reflect new data flow and any consequential updates to existing data flows.

Impact on other Configurable Items	
Configurable Item	Impact
Market Index Definition Statement	Updates to this document may be required to reflect the revised use of Market Index Data under the BSC.
Loss of Load Probability Calculation Statement	The Loss of Load Probability Calculation Statement will be established as a new item on the BSC Baseline Statement.

Impact on Core Industry Documents and other documents	
Document	Impact
Grid Code	Changes will be required to the arrangements for the system warnings in relation to Demand Control instructions and notifications.
Data Transfer Catalogue	Changes will be required to reflect the new DTC data flows that P305 will introduce.
BSAD Methodology	Changes will be required to these documents as a result of this Modification.
SMAF Methodology	

Other Impacts	
Item impacted	Impact
Imbalance Pricing Guidance Note	Changes would be required as a result of this Modification.

Other Impacts	
Item impacted	Impact
Electricity Trading Arrangements Beginners Guide	

5 Implementation

Recommended Implementation Date

The Workgroup recommends that, should P305 be approved, it is implemented on **5 November 2015** as part of the November 2015 BSC Systems Release.

The Workgroup notes that Ofgem highlighted in its Final Policy Decision that it seeks its proposed reforms to be implemented as part of the November 2015 BSC Systems Release, which will go live on 5 November 2015, to introduce these changes ahead of the winter 2015/16 season. It therefore strongly urged the industry to facilitate this approach to the best of its ability. The Workgroup agrees that P305 should be implemented on this date, if approved.

ELEXON will be able to implement the necessary BSC central system changes for P305 in time for this date based on the anticipated date by which an Authority decision is anticipated[2]. The Transmission Company initially noted a lead time of up to 18 months, but as the solution has been further developed and clarified it has subsequently noted that it can meet a November 2015 Implementation Date provided that no substantial changes are made to the requirements specification after January 2015.

In the industry Impact Assessment, DSOs noted lead times of up to six months to implement any necessary changes, while Supplier Agents noted lead times of up to 12 months. These participants will be directly impacted by P305, due to their involvement in the 'bottom-up' process for calculating the total Demand Disconnection volume. However, these lead times were based on the original requirements for this process, which have been amended since the impact assessment was issued. Revised lead times for these participants will need to be obtained as part of this Assessment Procedure Consultation.

BSC Trading Parties noted lead times of between six and 12 months to implement P305, with some participants preferring longer if possible. However, Trading Parties will not be directly impacted by P305 in terms of mandatory implementation requirements, with all impacts on these participants understood to be consequential.

Assessment Consultation Question
Do you agree with the Workgroup's recommended Implementation Date? *Please provide your rationale?*
The Workgroup invites you to give your views using the response form in Attachment B

[2] The P305 Final Modification Report is anticipated to be sent to the Authority in mid-March 2015.

6 Summary of Workgroup's Discussions

This Section 6 summarises the areas discussed by the Workgroup and its conclusions in respect to those areas. A page reference has been given to each area indicating where in Section 7 you can find the detailed discussions on that area. You are advised to read this Section first before turning to the relevant parts of Section 7 that you wish to follow up on.

The Proposer's initial views against the Applicable BSC Objectives can be found in Section 8. The Workgroup has not provided its initial views or recommendation at this time as it believes it will be better able to do so when it has obtained industry views and impacts, has had further time to consider the accompanying analysis and has decided upon its preference with respect to a potential Alternative Modification.

Summary of the Workgroup's discussions and conclusions

The Workgroup discussed and agreed the following areas:

- Most of the Workgroup did not agree with the proposed change to the PAR value, and proposed several alternative options to be considered. However, it was unable to come to a consensus as to which approach should be followed, though most favoured a smaller reduction. The Workgroup has elected to seek industry views on the various options. There was also consideration of whether the PAR values proposed by P305 and P316 need to be co-ordinated. (Page 22)
- The Workgroup agreed that there should be a single imbalance price. (Page 25)
- The Workgroup agreed that Market Index Data should be used to set the imbalance price when NIV was zero, and so believed that this data should remain unchanged by P305. (Page 25)
- All STOR actions should be published on the BMRS in disaggregated format, with both the Utilisation Price and, if applicable for that action, the RSP. These will be published after the Settlement Period has been completed. (Page 26)
- The Workgroup agreed that the RSP should only be applied to STOR actions and should be calculated as the product of LoLP and VoLL. (Page 27)
- The Workgroup considered analysis of the 'dynamic' LoLP function developed by the Transmission Company, and made amendments to the calculation based on the results of this analysis. The amendments addressed the main issues with the dynamic approach, but some Workgroup members remained concerned that the function was unpredictable, was a measure of plant availability rather than margin and was not as transparent as members would like. The Workgroup therefore developed an alternative 'static' function based on the use of historic output data produced by the 'dynamic' model, which would calculate LoLP values based on the de-rated margin in a given Settlement Period. A majority of Workgroup members prefer this alternative approach. (Page 28)
- The Workgroup agreed that the LoLP calculation should enable a signal to be provided to participants ahead of real time to allow them to react to any potential issues. The Workgroup therefore agreed that Indicative LoLP values produced by the proposed 'dynamic' function in the run-up to a Settlement Period should be published at the times stated in Section 3 with the Final LoLP value (to be used in the RSP) calculated and published at Gate Closure. The Workgroup considered

multiple options for the lead time at which a Final LoLP value should be determined under its alternative 'static' LoLP function, ranging from Gate Closure for the Settlement Period to 24 hours ahead of the Settlement Period. However, it could not come to an agreement and has elected to seek industry views on the various options. It was also questioned whether the LoLP could be 'gamed'. (Page 35)

- The Workgroup agreed with the VoLL values put forward by the Proposer and the times at which each step change takes effect. (Page 40)
- The Workgroup disagreed with the original proposal that the Authority could direct a change to the VoLL value. A VoLL review process to sit under BSC governance was developed, which Ofgem agreed could be adopted into the Proposed Modification in place of allowing the Authority to direct changes (this review process would also be included in any Alternative Modification developed). In any event, BSC Parties would still be able to raise a Modification to propose a change to the VoLL value at any time. The Workgroup agreed the VoLL value should not increase automatically in line with inflation. (Page 41)
- Demand Disconnection and Voltage Reduction events would be treated under the BSC as types of Demand Control events that would feed into the imbalance price. However, automatic Low Frequency Demand Disconnection (LFDD) events would be treated as system balancing actions and would be tagged accordingly. Notifications of all forms of Demand Control events will be published on the BMRS, and these notifications would be used to derive the 'top-down' estimate of the total Demand Control volume for use in the imbalance price calculation. (Page 45)
- The Workgroup could not, within the timescales available, develop a method for estimating the total volume affected by a Voltage Reduction event for use in the 'bottom-up' estimate of the total Demand Control volume. It was agreed that it was not vital that this aspect be included initially and that it should be considered separately. Consequently, only Demand Disconnection events will be included in the 'bottom-up' estimate. (Page 46)
- The Workgroup has developed a process for correcting participants' imbalance positions following a Demand Disconnection event, which will require action from DSOs, Supplier Agents and BSC Agents to complete. This process needs to be as accurate as possible and therefore should account for voluntary actions where possible. The Workgroup has further developed the Non Half Hourly (NHH) Supplier correction process from the proposals issued in the Impact Assessment, and seeks views from DSOs and Supplier Agents on this. (Page 47)
- It was agreed that the 'bottom-up' estimate of the Demand Control volume should not feed into the imbalance price calculation, but that the 'top-down' approach should be used at all Settlement Runs. (Page 50)
- The Workgroup considered what impact the Continual Acceptance Duration Limit (CADL) may have on the processes under P305, but is not proposing any change to this value at this time. (Page 51)
- Members believe that there will be impacts on participants' Credit Cover as a result of P305 (primarily, Trading Parties anticipate that the amount of Credit Cover they will need to lodge will increase as a result of potentially higher imbalance charges), but are unable to quantify what these impacts may be. (Page 51)

- The Workgroup has discussed the substantial qualitative analysis, forward-looking modelling and historical modelling undertaken under the EBSCR, including input from Ofgem and the EBSCR modelling provider. It has requested additional analysis based on historical data from ELEXON. This historical analysis will be published in due course; the Workgroup has not yet been able to consider the full results. (Page 52)

7 Workgroup's Discussions

This Section 7 covers the detailed discussions from the Workgroup on the P305 solution and related areas. You are advised to read the high-level summary of the Workgroup's discussions in Section 6 first, which contains page references to the relevant parts of this Section 7 that cover the detailed discussions on that area. You can then use these references to turn straight to the parts of this Section 7 that you wish to follow up on.

The discussions in this Section have been generally ordered by solution area, following the order given in Section 3. Any discussions areas not relating to a specific part of the solution can be found at the end of this Section.

What PAR value should be set?

The EBSCR proposed that P305 would reduce the PAR value to 50MWh upon implementation before making a further reduction to 1MWh in 2018. The Workgroup was generally supportive of a phased approach to lowering the PAR value, but some members had concerns over the marginal values proposed by the EBSCR, and felt a more cautious approach to reducing the PAR value should be considered, though there was minority support for accelerating the move to a marginal 1MWh PAR value.

Concerns around flagging and tagging and possible distortions

A concern was raised over the impacts that incorrect tagging of system actions by the Transmission Company could have on the imbalance price. The Transmission Company now has the ability to retrospectively correct erroneously tagged or untagged actions which should mitigate the risk of any flagging error having an enduring impact on a given Settlement Period's main imbalance price. Furthermore, it does retrospectively check all tagged actions to ensure that they were correctly tagged, although it doesn't check the actions it did not tag to check whether they should in fact have been tagged. Members felt this created the potential for an action that should have been tagged out to go on to set the imbalance price. Members considered that the Transmission Company has a tendency to 'over-tag' actions, and so it is unlikely that an action that should have been tagged would not be. However, other members felt that a formal process for allowing participants to challenge the Transmission Company's system action tagging should be introduced to mitigate the potential impacts.

One member was concerned that the use of marginal values could amplify existing inefficiencies in the current calculation. Following on from the tagging concerns above, they noted 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. They noted that without these potential distortions they would be in favour of moving to a value of 1MWh.

Other members agreed that a cautious approach should be taken, with a value of 100MWh to 250MWh being implemented at first and subsequent changes being raised once the effects had been observed and any issues better understood. This also allows the market more time to adapt to the new arrangements. There were concerns that, with the rejection of P304/P314 (which would have introduced an intermediate PAR value) P305 is proposing to change the PAR value straight from 500MWh to 50MWh.

EBSCR PAR analysis

Ofgem's proposal for the reduction in the PAR value draws on the analysis undertaken under the EBSCR, available on the EBSCR page on the Ofgem website.

For rationale and evidence underpinning Ofgem's proposals for the PAR value, please refer to:

- EBSCR Final Policy Decision 2014 p13-15
- EBSCR Final Policy Decision Impact Assessment 2014 p33-34
- EBSCR Draft Policy Decision 2013 p15-18
- EBSCR Draft Policy Decision Impact Assessment 2013 p32-35

However, other members were in favour of moving to 50MWh, or even directly to a lower PAR value. They suggested that the Transmission company tends to apply a particularly cautious approach to the flagging and tagging of system balancing actions, and that the marginal imbalance price is a good reflection of the expense Parties would have otherwise had to incur to address the imbalance themselves. Others felt that the PAR value is currently 500MWh, as introduced by P205 'Increase in PAR level from 100MWh to 500MWh', and not 100MWh, as originally proposed under P194 'Revised Derivation of the 'Main' Energy Imbalance Price', because previously system constraints were not being tagged and flagged. Given this issue has been addressed under P217 'Revised Tagging Process and Calculation of Cash Out Prices', the logical next step is 50MWh as a stepping stone to 1MWh. It was also considered whether setting too high a PAR value may undermine the intent of the EBSCR, and so may be rejected by the Authority.

Staggered and phased PAR reduction approaches

Workgroup members felt that a staggered approach to lowering the PAR value would be beneficial, and that a less marginal value than put forward under the proposed solution should be the first step, to allow the impacts to be assessed before lowering the value further. The impacts of a lower PAR are not linear, and are likely to get steeper as the PAR value gets closer to 1MWh. A jump from 500MWh to 250MWh, as had been proposed by P304, or possibly as far as 100MWh should have relatively little overall impact; however, once the value goes below 100MWh the effects and impacts will begin to be more noticeable. The Ofgem Representatives were cautious about such an approach, feeling that this could create uncertainty in the industry as to whether the next step was to take place, particularly if this was explicitly linked to the achievements of pre-set targets, and that this may delay or dilute the implementation of the efficient solution. Other members queried why a phased approach is necessary, arguing that if a lower value (such as 1MWh) is seen as ultimately beneficial then the industry should move directly to it.

It was noted that by placing all the steps (the subsequent value and when it would take effect) for a phased approach in the BSC at the point P305 was implemented would provide clarity and certainty that a further reduction would take place, the size of the further reduction and when it would take effect. It would also mean those steps would take place unless and until a further Modification was raised and approved to change that.

PAR review process

It was considered whether a PAR review process should be introduced, to allow for regular reviews of the PAR value, similar to the agreed VoLL review process (see below). However, members did not see the benefit of this, noting that if anyone wanted to propose a change to the PAR value then they could simply raise a Modification. All of the analysis that would be carried out under a review would be carried out under a Modification, and so there would be no benefit in introducing a new review process. The Ofgem Representatives agreed with this view.

PAR value options

The Workgroup noted that a PAR value of 1MWh was deemed by Ofgem to be the best value on the basis that this reflected the conclusion of the EBSCR assessment.

At this stage, the Workgroup is considering several potential PAR values that could be adopted. The Proposer has confirmed that they do not intend to change the approach to PAR values originally put forward in the Proposed Modification, and so any alternative PAR changes would need to form an Alternative Modification. The values being considered by the Workgroup are:

- 50MWh upon implementation then 1MWh from 1 November 2018 (proposed solution);
- 250MWh upon implementation then 100MWh 12 months later;
- 100MWh upon implementation with no further change under P305;
- 50MWh upon implementation with no further change under P305; and
- 1MWh upon implementation with no further change under P305.

The Workgroup believes it is unable to determine which would be the most appropriate option to progress until it has had a chance to fully consider ELEXON's historical analysis. However, there is no clear consensus among members at this time as to which approach should be progressed.

Assessment Consultation Question
Please provide your views on what PAR value(s) should be proposed and whether you believe a phased approach should be adopted. *Please provide your preferred PAR value option of those under consideration and your rationale for this and, if you have an alternative approach, please specify your proposed PAR value(s), your proposed timescales for phasing (if applicable) and your rationale for your proposal.*
The Workgroup invites you to give your views using the response form in Attachment B

One member asked how many Bids or Offers tend to form the price under different PAR values. The Ofgem Representatives noted this had been considered under the EBSCR, and that for a PAR value of 1MWh an average of three to four actions would set the price, rising to six for a PAR value of 50MWh. This is compared to around 15 under the current PAR value of 500MWh. Even under a 1MWh PAR value, it is possible that actions from several different Parties could contribute to setting the imbalance price.

How do the PAR values proposed by P305 and P316 interact?

The situation around the potential interactions between P305 and P316 are difficult to consider, given the uncertainty around possible alternative solutions for each Modification and the possibility that there is still scope for the PAR value and Implementation Date of the P316 Proposed Modification to be changed.

At this stage, both Modifications have the same proposed Implementation Date of 5 November 2015. However, 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. If the approaches to the reduction in the PAR value did not align between the two Modifications then there would be a possibility that the PAR value approved under P305 would then overwrite that approved under P316.

As the PAR values proposed under each Modification stand, should both be approved and should P316 be implemented earlier than P305, P316 would introduce a PAR value of 1MWh upon its implementation. P305 would then raise the value to 50MWh upon its implementation before returning the value to 1MWh in 2018.

P305 and P316 are two separate Modifications, and neither can be dependent or reliant on the other. However, the Workgroup has noted that co-ordination on this aspect of the solution should be considered to facilitate a possible phased implementation of the EBSCR conclusions.

Should there be a single imbalance price?

The Workgroup agreed with the Proposer that a single imbalance price should be applied in place of the dual imbalance prices currently in use, and agreed with the proposed approach for doing so.

Should Market Index Data be retained?

The Workgroup noted that P305 would remove the Reverse Price methodology as both SBP and SSP would be calculated using the Main Price methodology. Members therefore considered whether Market Index Data would still be required, as its only use under the BSC is in the calculation of the Reverse Price.

It was highlighted that a method for producing an imbalance price would be required in the event that the NIV was equal to zero. Although this is a rare event that has happened on only a handful of occasions in the last decade, this scenario can occur and a method for resolving it would be required. Suggestions that had been put forward included setting the price to zero, setting it equal to the previous Settlement Period or using the Market Price for that Settlement Period.

It was felt that setting the price to zero would not be appropriate as, while the system may have been perfectly balanced, costs would have been incurred to achieve that position. Additionally, the price of the previous Settlement Period may not be reflective of the price in the relevant Settlement Period (for example if a STOR action priced at a high RSP had set the price in the previous Settlement Period, but the relevant Settlement Period fell outside the STOR Window).

One member also suggested a method where, should the NIV equal zero but actions had been taken by the Transmission Company then a price could be derived from the highest priced accepted Bid and the lowest priced accepted Offer. Another member suggested using the last action taken that resulted in the NIV becoming zero. It was felt by these members that this would retain the principle of the marginal price being put forward by P305, and that if actions had been taken to balance the system then these should be used to set the imbalance price. Overall though, Workgroup members were not in favour of developing these more complex methods, given the expected frequency of them being used and also as they would not work in scenarios where no Bids or Offers had been accepted and so a further method would be required for these cases.

Workgroup members felt that the Market Price was a fair price to use in these scenarios, as no-one would be disadvantaged by this. It was also noted that, while Market Index Data is only used for the Reverse Price methodology under the BSC, it has many other applications elsewhere in the industry. The Workgroup noted that the total cost to ELEXON (and thus BSC Parties) per annum to maintain Market Index Data was around £330k, although a breakdown of these costs could not be made available due to commercial sensitivity with the Market Index Data Providers. While there would be cost-savings under the BSC to remove Market Index Data, some members felt these savings could be dwarfed by the costs incurred elsewhere to establish alternative methods to use in place of this. The Workgroup therefore felt that it would be prudent to leave Market Index Data untouched by P305 and to instead investigate this separately, and agreed that this data would continue to be published by ELEXON separately for each Settlement Period. It therefore also concluded to use Market Index Data to set the imbalance price when the NIV is zero.

It was noted that rules around imbalance prices are being drawn up under the forthcoming European Balancing Code, which could prevent the use of Market Index Data to set the prices. However, it was noted that this Code is still only in draft form, and that any changes required from it for imbalance prices are unlikely to need to be implemented before 2018. The Workgroup therefore elected to ignore this element under P305, noting that it should be picked up under any wider changes to implement the Code.

How should STOR actions be reported?

P305 proposes that all STOR actions will be included in the imbalance price calculations as actions priced at the greater of their respective Utilisation Price (the price incurred by the Transmission Company in calling upon the action) or the RSP for that Settlement Period. The Workgroup discussed how this would be reported, and agreed that it would be beneficial to see the Utilisation Price of each action even if it was subsequently replaced with the RSP.

It was therefore agreed that the Transmission Company would send the BMRA all STOR actions taken and the Utilisation Price of each action. Both the Utilisation Price and, if applicable to that action, the RSP that replaced it would be published on the BMRS for each STOR action. All STOR actions would be sent from the Transmission Company to the BMRA in dis-aggregated format alongside Bids and Offers, with a flag to differentiate whether it was a STOR action or not.

The volume of a STOR action would also be that which the Transmission Company had instructed from the action, rather than the volume actually delivered, as this would be consistent with how similar actions such as Bid-Offer Acceptances (BOAs) are currently reported. Workgroup members felt that an 'actual' volume could take a significant amount of time to calculate, and that if the industry wants prompt pricing then it cannot wait for this volume to be calculated. Furthermore, feeding a revised volume in to the calculations at a later date could result in radically different prices being produced at later Settlement Runs.

It was noted that the RSP would only be applicable in Settlement Periods that fell within a STOR Window, as these would be the only times when STOR actions could be called upon. The start and end of these windows will be either on the hour or the half-hour, and so align with the start and end times of Settlement Periods. Therefore, as long as the actions are provided to ELEXON at Half Hourly (HH) granularity it would be able to apply RSP to the parts of an instruction within a STOR Window while ignoring the rest. Sites that hold a STOR contract with the Transmission Company can elect to operate outside the STOR Windows of their own volition, but would operate and be treated as any other participant would in those circumstances.

Some members believed that STOR actions should be published as soon as possible when called upon, so that the industry is made aware of this and the possibility of the RSP being applied in that Settlement Period. This would be more important in summer when it is much harder to forecast periods where STOR actions may be called upon. Such events may not be due to system scarcity but simply a result of generation sites taking periods of planned outage, resulting in times when the system doesn't look tight when considering demand but in reality is, due to reduction in generation. The Transmission Company noted that there is a degree of confidentiality around STOR contracts which would make publication of the details difficult ahead of time.

Another member countered that STOR actions would most likely be called upon after Gate Closure, where participants would be unable to react for that Settlement Period, and so questioned the benefit of early publication of STOR actions. They also noted that Settlement Periods where STOR is called upon are likely to be Settlement Periods where the Indicative LoLP value was high, and so participants would have had some visibility in advance through these values.

Overall, it was agreed that STOR actions, their Utilisation Price and, if applicable, the replacement RSP would be published on the BMRS after the Settlement Period was complete, at the same time as the indicative imbalance prices.

How and when should the RSP be applied?

One member queried why only STOR actions had been singled out under the EBSCR, and whether other types of action could be subject to the RSP, such as Supplementary Balancing Reserve (SBR) and Demand Side Balancing Reserve (DSBR). They felt that scarcity pricing should be applied more generally to all Settlement Periods, and not just those in STOR Windows, and could not see where reserve came into the equation.

Other members responded that the RSP is only being applied to STOR actions as these are the only actions that aren't priced at the time of use, with the Utilisation Prices for STOR actions set in advance and therefore not reflecting the prices at the time they are called upon. Furthermore, availability fees are set at a fixed level and therefore do not reflect scarcity. All other types of action are priced at the time of their use, and so would at least partly reflect the prevailing prices at the time of use. The RSP is designed to better reflect the price of STOR actions. One member noted that SBR and DSBR should not be included as these are not technically treated as Balancing Services Adjustment Data (BSAD) now, and that the concept of the RSP function is to capture the value that people would be willing to pay that had not been captured within the Utilisation Price.

The first member also queried why participants would price Offers below the expected scarcity price if they knew they could get a higher price for their action. It was noted that the prices offered by participants would not necessarily reflect scarcity if more economic options were available. Furthermore, participants may elect to submit lower prices to make it more likely they would be called upon, which is a feature of a competitive market.

The Workgroup also considered whether the proposed calculation of RSP as the product of the LoLP and VoLL values was the right function, or whether an alternative method could be applied that would 'uplift' the RSP for a given LoLP value. One proposed option discussed was that the RSP could be the lesser of the prevailing VoLL value in the BSC or the product of the LoLP value and 'true VoLL'. This would have the result of the RSP, and therefore the imbalance price, reaching the VoLL value at a LoLP value of potentially significantly less than 1 (100%), strengthening the incentive to ensure plenty of capacity was available. Workgroup members could not see the justification for this approach as P305 was predicated on the idea of RSP rising gradually to the VoLL value as the LoLP got closer to 1 (100%).

How should the LoLP be calculated?

In its Final Policy Decision, Ofgem left it open to the P305 Workgroup to develop the calculation for producing a LoLP value, within a given framework. Two calculation methods have been developed:

- The Transmission Company has produced a 'dynamic' calculation, which would be calculated in the run-up to each Settlement Period and would be based on plant availability data at that time. This is referred to in this document as the 'proposed LoLP function'.
- The Workgroup has developed a more 'static' function calculation, under which a function relating the de-rated margin in a Settlement Period to a LoLP value would be calculated prior to a given period of time (e.g. a winter period) using historic data over previous years. This function would then apply to all Settlement Periods during the applicable period. This is referred to in this document as the 'alternative LoLP function'.

The details of each method can be found in Attachment A.

The agreed LoLP calculation will be documented in a new document, the LoLP Calculation Statement, to sit on the BSC Baseline Statement. This will mean that any errors in the calculation of a LoLP value will be deemed a Settlement error and will need to be resolved through the Disputes process. This would also make the execution of the process subject to the BSC Audit. All changes to this document would need to be approved by the Authority.

Consideration of the proposed dynamic calculation

The 'dynamic' calculation is designed to measure the probability of the available generation being less than the expected amount of generation needed to meet the expected demand in a given Settlement Period. The calculation is based in part on an expected availability or reliability factor for each fuel type. These availability factors have been calculated based on the stated availability of each BM Unit a certain amount of time before a Settlement Period compared to its actual availability in that Settlement Period. These values would be updated each year based on the results from the last three calendar years and stated within the LoLP Calculation Statement.

The Transmission Company has also proposed to produce two sets of these values, split between summer (April to September) and winter (October to March). This is designed to reflect the difference in reliability or availability between these two times, which can be more pronounced for some fuel types such as wind. Workgroup members considered whether further splits should be considered, such as between day and night or between Working Days and non-Working Days.

The Workgroup considered the scenario of a BM Unit indicating that it was available ahead of a Settlement Period, but upon commencing generation a fault occurred that prevented the BM Unit from performing. It was queried how this could be factored into the calculation, but one member noted that there is always a chance of this happening, and another noted that all information regarding availability would be provided in good faith. There is always a greater risk of failure with a BM Unit commencing generation compared to one that is already running. The Transmission Company noted that there was insufficient information on individual BM Units to break the data down to that granularity, and that fuel type is the most pragmatic grouping available.

The calculation includes a fixed value to represent the amount of reserve that the Transmission Company will hold to use as last resort, for example for frequency response. The Transmission Company would wish to hold on to this reserve until it absolutely had to call upon it, preferring to initiate a Demand Control event in part of the country rather than risk a system-wide blackout due to no reserve being left to call upon to manage the frequency. A fixed value was selected as a more dynamic parameter would be more complicated to produce and would require more data input. It was also felt that this value should be a fixed value tied to a publicly-available value to maximise transparency and aid other participants in replicating the LoLP calculation should they wish. It was believed that the Security and Quantity of Supply Standard (SQSS) value should be used, and this Infrequent Infeed Loss Risk value is 1,800MWh.

Each BM Unit is assumed to either be fully operational or completely unavailable in a given Settlement Period, which, while not fully reflective of reality, was considered a reasonable assumption. However, gas plants can have multiple shafts under a single BM Unit, and so the assumption put forward in the calculation is that a gas BM Unit is modelled as two Units with half the capacity on each. Averaged over all gas BM Units, which can have anywhere from one up to five shafts, analysis carried out by the Transmission Company suggests this assumption to be sufficiently accurate enough when compared to reality. One Workgroup member was not certain about this, and questioned whether the assumption would affect the reliability of the calculation, and if it did then it would need to be reconsidered.

The Workgroup considered how Interconnectors should be factored into the calculation. Interconnectors can only be subjected to Demand Control in proportion to the level of Demand Control taking place within GB. Otherwise, the only actions that can influence Interconnector flows would be emergency instructions between SOs, which would effectively reduce the chance of losing demand elsewhere. The Workgroup noted that Interconnectors had therefore not been factored into the LoLP calculation, and observed that this may mean the LoLP value is being overstated as a result.

The Workgroup noted that the calculation should aim to be as accurate as possible. If participants begin to use the results in a serious way and issues were uncovered later on, the calculation and the data feeding into it could come under a lot of scrutiny. It was felt by one member that the LoLP value would never be totally accurate as a forecast due to the assumptions being used.

Consideration of the Transmission Company's analysis and development of the function

The Transmission Company's proposed function has undergone several iterations. This section summarises the discussions and analysis of the Workgroup across previous iterations that led to the development of the current proposal detailed in Attachment A.

Analysis on the original iteration

The Transmission Company's analysis of the original version of the dynamic LoLP function was focused on 2013 data, which was noted to be a year with a lot of available margin on the Total System, but was also just prior to plants that have elected not to comply with the Large Combustion Plant Directive (LCPD) beginning to close down, which will have a detrimental effect on available margin in subsequent years.

The Workgroup found the results surprising, as they suggested that the highest LoLP values were appearing at times outside the STOR Windows, with several of the more notable values occurring within an hour of midnight. Members were concerned whether the proposed LoLP function was providing the correct signals if high LoLP values were being produced at times when participants would not intuitively expect the system to be tight, such as overnight. One member noted that the overnight period would generally see low demand and plenty of available capacity. While the margin may be low if some generation units were unavailable overnight, the system would not expect to be 'stressed'. They intuitively felt that the proposed LoLP function was not providing the expected results.

It was noted that these midnight values all occurred over the same night, 13 November 2013, and that the Transmission Company had called upon reserve during this time, indicating this was a legitimate, albeit anomalous, event. The LoLP values for these periods would not set the imbalance price though as the RSP would only apply within a STOR Window. The Transmission Company subsequently amended the dynamic function to account for this discrepancy by better reflecting the patterns of plant availability overnight, and this amendment forms part of the current proposal.

It was also highlighted that, within the STOR Windows, not one Settlement Period across 2013 had a LoLP value high enough for the RSP to replace the Utilisation Price, and only around 20 Settlement Periods[3] had a Final LoLP value in excess of 0.01 (or 1% probability). The Ofgem Representatives noted that their historical analysis had suggested the RSP could have a greater impact (between 1-3% of the time), but recognised that whilst this analysis was based on the information available at the time, the detailed LoLP calculation had not yet been developed. Workgroup members wondered if this was a sign that the STOR Windows may not be in the right places.

The Workgroup also considered modelling undertaken by the Transmission Company for 11 February 2012, which was a date on which a Demand Control event had taken place. Several calculations of the LoLP values across that day had been carried out, using availability values calculated for a range of times from the hour-ahead Maximum Export Limit (MEL) values to the winter outlook data submitted at the start of the preceding October. It was noted that the LoLP values generated from the hour-ahead data were very low values of less than 0.01 (1%), while the values arising from the winter outlook availability data were significantly higher, getting near to 1 (100%) on a couple of occasions and above 0.5 (50%) for a large amount of the day.

It was noted that this was an exceptional circumstance in which temperatures of -18°C had been recorded. On that occasion, gas BM Units had continually recorded availability up until mid-morning, when a large number of them froze at around the same time, resulting in the Transmission Company initiating Demand Control. A type fault across a particular fuel type is an incredibly rare event, and this event was unforeseen by the whole industry, with even the Transmission Company being unaware of the potential for this issue until almost the moment it occurred. Consequently, it would have been unlikely this would have

[3] There are 17,520 Settlement Periods in a non-leap year.

Transmission Company's LoLP analysis

The results of the Transmission Company's analysis can be found in Attachment A.

The raw LoLP data produced by the Transmission Company will be available to download from the ELEXON Portal in due course.

shown up in the Indicative LoLP values for the Settlement Period in which the event occurred, and for later Periods only upon commencement of the event, by which time the industry would have become aware anyway. The Workgroup therefore felt that this event may not be a suitable one in which to test the calculation or base conclusions on, as the LoLP would be expected to be very low when no issues are foreseen. Furthermore, it was noted that the SBPs for that day seemed to produce a clearer signal of the times when the system was tight than the LoLP values did. However, there is only one other Demand Control event to have occurred over the last few years which can be investigated, and this was for an automatic Low Frequency Demand Disconnection event, the actions for which would be system action flagged and so would not impact imbalance prices.

Analysis on the second iteration

Following the amendments made to the model following the original analysis, the Workgroup requested the Transmission Company undertake further analysis for the week beginning 13 October 2014, which had been noted as a period of low margin and high imbalance prices due to high-priced Offers being accepted. The Workgroup felt that this was the closest scenario available to it to a full Demand Control event that it could use to properly assess the proposed LoLP function. The Transmission Company Representatives noted that they had been close to issuing warnings to the wider industry during this time.

The analysis initially showed significant spikes in the Final LoLP values calculated at Gate Closure compared to the Indicative LoLP values calculated one hour previously, which some members were concerned could not have been predicted, and with LoLP values rising above 0.5 (50%) at Gate Closure when they had been below 0.1 (10%) one hour earlier, there was the potential for significantly high imbalance prices to be set that participants could not have anticipated and for which little signal had been perceived to have been available. While there had been issues during that week, the members felt they had not been severe enough to warrant an imbalance price in excess of £2,000/MWh.

Members felt that this pattern could be expected, with high LoLPs at the day-ahead point when there is greater uncertainty, then values reducing over time, then rising sharply at the last minute when a generation unit experiences a sudden outage. However, this is not what they believed should feed into the imbalance price as such outages cannot be predicted. Furthermore, members were concerned that such high LoLP values were being produced during a fairly warm and windy October period.

The Transmission Company Representatives identified that this spike at Gate Closure may have been caused by the assumption applied to the Notice to Deviate from Zero (NDZ), which meant that the MELs of units were only counted if that unit was available at the start of the Settlement Period. The Transmission Company took an action to rerun the model applying the assumption that a unit's MEL would be accounted for if it could be synchronised by the end of the Settlement Period. When the model was rerun with this assumption accounted for, this change resulted in the spikes being removed. The Transmission Company also amended its availability factors to use the same values at all calculation lead times, which reduced the high day-ahead Indicative LoLP values that had also been observed. These amendments form part of the current proposal.

Analysis on the current iteration

Following these amendments, the model was rerun for all Settlement Periods across 2013 and up to mid-October 2014. The results produced by this re-run indicated that the amendments made to the function had achieved the desired effects. The highest LoLP value produced at Gate Closure was a result of a combination of tight margins and a generation outage between two hours ahead and Gate Closure, although even this value would have been too low for the RSP to feature in the imbalance price. It was considered by some members that high LoLP values would only arise if there was a sudden generation outage coinciding with a period of low margin.

Members were generally satisfied that specific concerns had been resolved. The Transmission Company and Ofgem Representatives noted that the analysis showed that whenever there was a high Final LoLP value, a warning had been provided by the Indicative LoLP values. Specifically, in every Settlement Period where a high Final LoLP value had been produced, this had been preceded by a series of Indicative LoLP values that were significantly different from those in 'normal' Periods. While some Workgroup members voiced their support for the proposed function based on this updated analysis, others were still concerned with the proposed function generally.

The results of the Transmission Company's analysis on the current iteration can be found in Attachment A, and the raw data produced by this work will be available to download from the ELEXON Portal in due course.

Is the proposed LoLP function correct?

The Workgroup considered whether the calculation would produce high LoLPs for many days at the day-ahead point, where data is less certain, and whether the values could be similar across most days. There was a feeling among members that LoLP values would likely start high and come down closer to real time as availability becomes clearer. If this was the case, participants may elect to ignore the LoLP values this far out. At the other extreme, they may react to the high chance of imbalance prices being set to the VoLL price, although it was noted that reaction to a high LoLP value would likely result in it subsequently falling as the signal of an initially high Indicative LoLP value could naturally lead to the Final LoLP value being much lower as participants react to the initial signal. One member noted that the way probability can work means that a Demand Control event may occur with only a 1% chance forecasted, or may not even with a 50% chance forecasted.

One Workgroup member was unclear what the values produced by the proposed 'dynamic' LoLP function were supposed to be showing. They expected the LoLP value to be higher in periods of higher demand, when there would be fewer actions available to the Transmission Company to call upon. They also felt that the Indicative LoLP values were not providing a systematic upward trend as margins tightened but were spiking sharply at Gate Closure in reaction to last-minute events such as sudden plant outage, which participants could not anticipate. They therefore did not feel that the proposed LoLP function was delivering what was required, and could not be seen as reliable. Other members agreed that the calculation should be questioned if it was producing high LoLP values at times when they would not be expected. However, the Transmission Company Representatives cautioned against subjectively manipulating the calculation to match the Workgroup's intuition, noting that the results of doing so would affect the whole market. They noted that the dynamic calculation was statistically robust, and that it is possible that the Workgroup's intuitive expectations are wrong.

It was felt by one Workgroup member that the LoLP value should measure the risk of reserve being dispatched when the Transmission Company was running out of capacity, as the Final LoLP value would then be used in pricing these reserve actions. The LoLP therefore needed to be able to measure the available capacity. Another member disagreed, noting that the LoLP was a measure of the chance of losing load. It was countered that this was why the Transmission Company procures reserve, in order to avoid this happening, and that it should be expected that the LoLP would lift prices when reserve was called upon.

It was noted that the LoLP values produced by the Transmission Company's analysis were very low generally, and that the subsequent RSP values would not impact imbalance prices. However, the analysis had focused on only the last couple of years, which had been generally benign and so low values were to be expected. One member also flagged that the country has historically held a good generation capacity, although it was questioned why reserve was needed if that was the case. The Ofgem Representatives also noted that the SCR's analysis showed RSP would usually only feature when the margin fell below around 2.5GW, and felt that the Transmission Company's analysis was consistent with the SCR's conclusions. Nevertheless, members were concerned that they could not draw firm conclusions on the function because of this, but it was felt that there was little point in re-running the analysis earlier than 2013 as there haven't been any notably tight periods in several years with which to assess the results against.

The Transmission Company Representatives queried whether the questions raised by the Workgroup suggested that LoLP was not what members wanted in the RSP calculation. They felt that the Workgroup's comments and concerns were around something more fundamental than just the LoLP itself, noting that its proposed function did what was asked of it. It was considered whether it wasn't the LoLP function that concerned members but the subsequent RSP function. Members responded that the concern was around the interaction between the LoLP value and the corresponding margin. They expected the highest LoLP values to occur when demand was rising sharply, as this would be the time when they would expect issues to occur. However, others noted that a high LoLP value should be a function of both demand and generation. It was also expected that Indicative LoLP values would start high for these times at the day-ahead point, and reduce over time as participants react to the signal.

One member felt that the proposed LoLP function seemed to be showing a 'loss of generation' probability, as it was mainly picking up plant failing close to real time. They felt that the proposed LoLP function reflects what the Transmission Company is doing with scheduled generation units but that this did not relate to the imbalance price. They felt this LoLP function was doing a good job of showing loss of generation, but it wasn't showing demand versus capacity and it did not enable the LoLP value be predicted, and so should not be used in setting the imbalance price.

The Workgroup also had concerns with the transparency of the proposed LoLP function's calculation, with several of the input parameters not being publically available. The Transmission Company Representatives flagged that it was primarily the MEL values that could not be published prior to Gate Closure due to confidentiality agreements. However, the forthcoming regulation on submission and publication of data in electricity markets (the Transparency regulation) (Regulation (EU) No 543/2013)[4], due to be implemented at the beginning of January 2015, would require indicative MEL values to be published, but only on a prospective basis. This would remove this element of opaqueness and would facilitate participants attempting to recreate the function.

[4] http://eur-lex.europa.eu/LexUriServ/LexUriServ.do?uri=OJ:L:2013:163:0001:0012:EN:PDF

Overall, some members were concerned with the proposed 'dynamic' LoLP function, believing it should not be implemented, and felt that an alternative solution should be developed, considering a more 'static' function may be appropriate.

Development of the alternative LoLP function

Some members noted that the Transmission Company must procure reserve based on some long-term measure of the probability of it needing to be used, and wondered if something similar could be used for producing LoLP values here. They considered that this would be a better measure of the margin than the MEL-based method under the proposed 'dynamic' LoLP function. The Transmission Company Representatives highlighted that the methods used to procure reserve long-term were very different to the methods used to balance the Total System in real time.

Members felt that the LoLP should be higher when margin was lower. Once it was understood how the margin is calculated, a function linking that to a LoLP value could be produced. This would result in a pre-agreed function published ahead of time, and participants could use this to forecast LoLP based on forecasts of demand or margin. Members agreed that, while a 'dynamic' function would be preferable ideally, a 'static' function was appealing due to the increased certainty it could provide to the market.

The Workgroup proposed an alternative LoLP function that would use the historic Final LoLP values produced from the proposed LoLP function for a given period of time to derive a relationship between de-rated margin and LoLP. For example, the historic Final LoLP values for the previous two winter periods would be calculated, and these values would be used to derive a relationship between the de-rated margin in a given Settlement Period and the corresponding LoLP value. For the forthcoming winter period, this function would be used to determine the LoLP value for a given Settlement Period, based on the forecasted de-rated margin for that Settlement Period. An RSP would then be derived from this as per the proposed solution. This function would be updated annually based on fresh historic data, as far in advance of the forthcoming period as possible. For example the winter function would be updated as soon as possible following the end of a winter period, so the revised function is available well in advance of the next winter period. There would also be different functions for different parts of the year (e.g. a summer/winter split, or by BSC Season). Please see Attachment A for more details on this proposed method.

Members agreed that this alternative LoLP function would be more predictable, and would provide participants with an ex-ante signal with which to trade against. However, it was noted that it was not dynamic as it simply relates the de-rated margin to a LoLP value, whereas imbalance prices are dynamic and react to the actions taken by the Transmission Company.

Although the process for calculating the function would be captured in the LoLP Calculation Statement, for which all changes would be subject to Authority approval, Workgroup members believed that any key parameters relating to this method would need to be written into the BSC. This would mean that those values could not change without a BSC Modification being raised.

The Proposer has confirmed that at this point they do not wish to adopt the alternative 'static' LoLP function as part of the Proposed Modification, and that they intend to keep the proposed 'dynamic' LoLP function. At this stage, a majority of Workgroup members support including the alternative LoLP function in any P305 Alternative Modification.

Assessment Consultation Question
Do you prefer the proposed 'dynamic' LoLP function or the alternative 'static' LoLP function? *Please provide your rationale*
The Workgroup invites you to give your views using the response form in Attachment B

How do LoLP and RSP fit in to the full solution?

The intent of the RSP function is to provide a price for STOR actions that reflects the conditions in the market at the time it is called upon. The results of the LoLP and the resultant RSP should be to provide a suitable price for these actions when they are called upon.

One Workgroup member was concerned that the whole RSP mechanism proposed by P305 was creating uncertainty for no real benefit, and queried whether it would add value to the overall arrangements. It was noted that in a liquid market prices would naturally rise to the RSP, but this is not happening. However, GB is the most liquid European market not counting those countries where participants are forced to trade. It was queried whether the imbalance prices were dampening the forward market. However, members did believe that the move towards an RSP for STOR actions was better than the current method of including them in the BPA. Nevertheless, the RSP cannot be assessed solely on its own merits in isolation, but on how it fits in with the rest of the full P305 solution.

It was questioned whether STOR actions should not be priced in advance at the Utilisation Price but instead priced on demand. It was questioned how a price on demand would be calculated, and what assumptions would need to be made. It was noted that the highest priced Offer could be a reflection of the market conditions that could be used. Assumptions would also need to be made on the relevant participant's short-run costs. One member noted that the price would be the price that would have been submitted had the action been taken under the BM rather than through a STOR instruction, and it was noted that STOR can be used ahead of an Offer if it is cheaper. Overall though, this idea was ruled out as participants would be unlikely to sign up to provide STOR in this situation, which would have a serious impact on the security of supply.

When should LoLP values be produced and published?

The Workgroup considered when Indicative LoLP values should be produced under the proposed 'dynamic' LoLP function and at what time in relation to the relevant Settlement Period the Final LoLP value should be determined under the alternative 'static' function and published under either option.

Can participants respond to the indicative signals?

One member queried whether participants would be able to respond to any signals in advance of Gate Closure, noting that participants don't have such signals now for imbalance prices generally. The Ofgem Representatives noted that the intent of having indicative signals was to warn participants of potentially high imbalance prices as a result of STOR actions being called upon or the initiation of a Demand Control event. They did not want such an event to be completely unpredictable, although they noted the potential for trade-offs to be made between criteria of statistical soundness, providing appropriate prices at the appropriate time, and providing a signal that Parties can react to. Signals should encourage participants to trade in the forward market to manage their positions, although it was felt that the very inclusion of RSP and VoLL in the arrangements would send a general signal to participants.

One member believed that smaller participants would usually need at least four hours to effectively respond to any signal, and that this would be dependent on there being sufficient liquidity with which to trade. They were concerned that as margin gets tighter liquidity tends to dry up, preventing participants from being able to trade out their position. They believe that participants need to be able to respond to signals, and that sufficient time needs to be given for them to react in to mitigate the risk of exposure to high imbalance prices. Otherwise, the arrangements proposed by P305 could be seen as a penalty rather than an incentive.

It was noted that the proposed LoLP function would provide a less reliable signal the further ahead of real time it was calculated, and that values produced further out would be less reflective of the situation. One member observed that this is just how markets work. Other members believe that a smooth glide-path is needed in the run-up to a Settlement Period to allow participants to be better able to trade, and it was felt the alternative LoLP function could achieve that as participants can use their own forecasts to assess what they believe the LoLP value would be. This could be enhanced further by having the Transmission Company publish forecasts of de-rated margin on the BMRS, and the Workgroup believed this would need to be a condition of the alternative LoLP function.

When should Indicative LoLP values be published?

Members noted that an indicative value needed to be produced sufficiently far enough in advance to incentivise participants to trade to avoid any potential Demand Control event from being needed and imbalance prices rising to at least the VoLL value. Members began by proposing that, for any given Settlement Period, an indicative value should be produced at 24, eight, four and one hour(s) prior to Gate Closure.

The Workgroup discussed how the 24 hour ahead value should be published, and whether it should be a 'rolling' calculation (i.e. carried out 24 hours prior to Gate Closure for a given Settlement Period), or calculated in a batch as part of the day-ahead information produced by the Transmission Company at 11:00 each day for all Settlement Periods up until the end of the next Operational Day. A member in favour of the latter argued that the Transmission Company would have much more information for a calculation carried out at 12:00 on a given day than it would for a calculation run at 09:00, and so values produced in this manner would be more meaningful. Other members argued that a rolling basis would be more consistent with the reporting required under the regulation on wholesale energy markets integrity and transparency (REMIT) (Regulation (EU) No 1227/2011)[5] and the Transparency regulation.

The Transmission Company representatives noted that information is constantly received, and is processed by the systems at the point of receipt. Therefore, all information that had been received when a calculation was performed would be included in that calculation. The day-ahead calculation simply collates all this information. However, some members were not convinced that a significant amount of data would not arrive just prior to the day-ahead calculations, and that any Indicative LoLP value calculated just prior to that

[5] http://eur-lex.europa.eu/LexUriServ/LexUriServ.do?uri=OJ:L:2011:326:0001:0016:EN:PDF

would be less useful for missing this information, especially as the value may not be revised for a further 16 hours. It agreed that, in addition to the specific times of eight, four and one hour(s) prior to Gate Closure, an indicative LoLP value is produced for all applicable Settlement Periods at 12:00 each day, and that there would not be a 24 hour ahead rolling Settlement Period-specific Indicative LoLP.

Another member highlighted that day-ahead trading on the Power Exchanges ceases at 11:00. They considered whether a further set of Indicative LoLP values should be produced at 08:00 each day to inform participants of the Indicative LoLP values over the subsequent Operational Day ahead of this deadline.

One member felt that calculating indicative values at specific times is prescriptive, and believed that the industry would prefer continual updates, although they conceded that this may be a tall order for the Transmission Company. They considered whether an Indicative LoLP value could be updated whenever new information is received by the Transmission Company that could materially affect the value. It was noted that data would be constantly received, and it would be difficult to determine what would be material, and that other forecast information published under the Grid Code and BSC Section V 'Reporting' is published at set times, rather than continually updated. A member thought that, if this was not feasible, the value could be re-calculated every half-hour even if no new information had been received. However, it was felt that this could result in 'data overload'. It was ultimately elected not to progress this idea.

The Transmission Company Representatives were concerned as to how accurate an indicative value calculated 24 hours ahead could be. They noted that a day-ahead value could be produced, but its accuracy would depend on how accurate the MEL values it had received at that time were. At this time, the Transmission Company would only possess a high-level idea of the expected generation and demand, and it is not until closer to real-time that the picture becomes clear enough to produce a meaningful estimate. However, other members felt that the Indicative LoLP values were more for the industry's benefit than for the Transmission Company, and that it would be for individual participants to determine whether the 24 hour ahead value was of worth to them or not.

Following this, one Workgroup member queried whether Indicative LoLP values should be calculated for more than just the next Operational Day. They noted that some smaller participants only trade during Business Hours, and felt that these participants would want a rough idea just before a weekend what the likely LoLP would be at the start of the next week. Taking Bank Holidays into account, they considered that extending the day-ahead batch of values calculated at 12:00, and possibly 08:00, to cover the next five Operational Days would be beneficial to these smaller participants. The Transmission Company Representatives reiterated their previous concerns over whether an indicative value at five days out would show anything at all. Other members responded that any information would be better than none, and noted again the view that it would be for participants to judge whether they should respond to the value or not. The Transmission Company Representatives noted this, but queried, while little information was better than none, whether the accuracy of a value this far out could result in this being misinformation.

Following Impact Assessment, the Transmission Company noted that it did not possess the data required to be able to produce Indicative LoLP values further out than as part of the day-ahead calculations. To calculate a meaningful result further out than that would require participants submitting data such as Physical Notifications (PNs) and MEL values earlier than currently. This would impact those participants. The Transmission Company also noted that it would be easier if the times at which LoLP values were produced were linked to the start of the Settlement Period and not to Gate Closure, noting that its systems were designed around the obligations under the Grid Code, and so it would be beneficial to align with this wherever possible. It proposed that indicative values are produced at 12:00 for all Settlement Periods up to the end of the next Operational Day, then at eight, four and two hours prior to specific Settlement Period beginning (equating to seven, three and one hour(s) prior to Gate Closure), with the final value being calculated one hour before the Settlement Period (equating to Gate Closure). The Workgroup agreed with this approach.

The Workgroup agreed that if a Final LoLP value could not be produced for a given Settlement Period then the last available indicative value for that Settlement Period would be used in its place. If no such value was available then the value would be null and the RSP for that Settlement Period would be set to zero. A flag would be included with each LoLP value produced to mark how it had been calculated, and whether it was an actual value or a defaulted value. Members noted that while this approach held a risk of an incorrect value being used, it was felt that this defaulting rule would be the most appropriate in this scenario.

When should the Final LoLP value be published?

Some Workgroup members expressed concerns at whether a Final LoLP value published for a Settlement Period at Gate Closure could influence participants to deviate from the position they had declared at Gate Closure, self-balancing in order to mitigate the impacts of imbalance prices rising to the VoLL value should they end up short. It was considered whether the Final LoLP value should not be published until after the Settlement Period had finished, alongside the indicative SBP and SSP for that Settlement Period, to mitigate this potential impact. However, other members noted that deviating from the declared position at Gate Closure would be in contravention of the Grid Code, although it was considered whether the penalties for this would be severe enough when compared to an imbalance price of £6,000/MWh. One member also highlighted that an indicative value would be published one hour before Gate Closure, which participants could respond to, and that participants should not be deviating after Gate Closure. It was considered whether participants reacting to a stressed system would be beneficial, but it was felt that it would not be if this put the stability of the system at risk. However, the issue of self-balancing exists now, and is unlikely to go away under P305.

Members also noted that the LoLP calculation is likely to be sufficiently transparent if all the data used in it was publicly available that any participant could calculate the Final LoLP value themselves at Gate Closure. In this scenario it makes little sense not to publish the value, as that would only bias against participants without the resources to do this themselves.

Overall, it was concluded that there would be no real benefit in delaying the publication of this value, and that in the interests of transparency it should be published as soon as it becomes available. Respondents to the industry Impact Assessment who expressed a view on this matter all supported this view, for similar reasons to those put forward by the Workgroup.

When should the LoLP value be determined under the alternative LoLP function?

The Workgroup discussed at what point a Final LoLP value should be determined for a given Settlement Period under the alternative LoLP function, based on the forecasted de-rated margin for that Settlement Period at the time of determination. The options that are being considered are:

- At Gate Closure, as this would be the most realistic estimate of the de-rated margin for the relevant Settlement Period.
- Two hours before the Settlement Period begins, as this would leave participants the final hour before Gate Closure to trade knowing what RSP would be applied should a STOR action be called upon.
- Four hours before the Settlement Period begins, as this would factor in the final wind forecast for the Settlement Period, and leaves participants more time to trade in response to the confirmed RSP for the Settlement Period.
- 24 hours before the Settlement Period begins, as this gives participants, and particularly smaller participants, significantly more notice of what the RSP for the Settlement Period will be.

These options are only being considered for the alternative LoLP function; the Final LoLP value under the proposed LoLP function would always be set at Gate Closure, as detailed above. This is because the alternative LoLP function is dependent on only one variable (de-rated margin), while the proposed LoLP function is dependent on many more variables that will change constantly in the run-up to Gate Closure.

Under this approach, a forecast of the de-rated margin will be published on the BMRS. This will remove the need for any Indicative LoLP values to be produced, as participants could observe the forecasted de-rated margin and use the function to derive the expected LoLP themselves.

Members felt that whichever option is chosen would be based on a trade-off between early certainty of the RSP and the accuracy of the forecasted de-rated margin. It was noted that the further out the LoLP value is determined, the greater the potential becomes for inaccurate signals, as a lot can change in the intervening space of time (potentially as long as 24 hours), including Parties reacting to the signal.

Some members are concerned that the forecasted de-rated margin may change considerably between 24 hours ahead of real time and four hours ahead of real time, and that a lot of this uncertainty comes from how much the wind forecast may change during this time. This will be considered when the Workgroup makes a decision on this matter, although the Transmission Company has since noted 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.

Assessment Consultation Question
How far ahead of real time do you believe the Final LoLP value under the alternative 'static' LoLP function should be determined? *Please provide your rationale.*
The Workgroup invites you to give your views using the response form in Attachment B

One member noted that a LoLP at any given point in time will be correct for that point in time, but that it becomes more representative closer to real time and that Gate Closure is the last point at which participants can take any action to affect the LoLP value. Another member noted that it is possible for the market to run out of options before this point, but also that the further out a participant trades, the more time there is for events to occur that makes that trade a detrimental decision. It was also considered that this discussion has been more about the signal provided by the LoLP value and not the actual LoLP value itself.

Could the LoLP value be 'gamed'?

One member considered whether participants could 'game' their MEL values in order to increase the LoLP and potentially increase prices in the wholesale market. However, other members considered this unlikely due to the reporting obligations imposed on the industry under the REMIT and Transparency regulations, under which participants are required to promptly report any unavailability, both planned and unplanned, and the subsequent restoration of that unavailability as soon as they become aware of this information. The penalties for erroneous reporting under these regulations are severe, and participants would likely lose significantly more from this than they could gain from gaming.

The sensitivity of the proposed 'dynamic' LoLP calculation to potential gaming of the LoLP calculation has not been considered in any detail by the Workgroup. However, following on from the last meeting one member raised the issue of the potential for market participants to influence the LoLP calculation by withholding plant. This could have the effect of indicating that there is limited unavailability of plant and a correspondingly high potential for lost load, which could influence cleared prices in the day-ahead or within-day markets.

What VoLL value should be set?

The EBSCR proposed that P305 would introduce an administrative VoLL value of £3,000/MWh upon implementation before rising to £6,000/MWh in 2018. The Workgroup was generally supportive of this approach.

One member queried whether the VoLL values proposed by P305 were appropriate, or whether lower values of £1,000/MWh or £2,000/MWh should be used to begin with. They were concerned that the high values being proposed had the potential to unintentionally adversely impact smaller participants. Another member noted that single-site generators would be at the greatest risk of adverse impacts, as they could potentially lose their whole generation output to an unexpected outage, creating a significant imbalance position. In contrast, while Supplier positions tend to be more unpredictable due to consumers' patterns of consumption it is unlikely they would be as significantly out of balance.

It was flagged that the VoLL values put forward under P305 had been calculated based on the assumptions the CM would pick up the rest of the expected impact. One member noted that these values were designed to act as an incentive for participants to balance their positions, and if there was a risk of a generally reliable single-site generator suffering an unexpected outage then they should be able to secure insurance against this. Furthermore, the VoLL values put forward had been based on extensive analysis and consultation carried out under the EBSCR, and that there was clear rationale for a VoLL value of £6,000/MWh. The proposal to begin with a VoLL value of £3,000/MWh was intended as an introduction for participants. Members felt there was no justification for other values to be put forward, and were content that the values proposed by P305 were appropriate.

EBSCR VoLL analysis

Ofgem's detailed analysis outlining why the administrative VoLL price is as proposed can be found in its consultation for the Draft Policy Decision, which ran between July and October 2013. In particular, please see Section 4 (p19-23) and Appendix 6 (p55-60).

Further information can also be found in the DECC-Ofgem study by London Economics on the Value of Lost Load for GB consumers and in Ofgem's Final Policy Decision.

Assessment Consultation Question
Do you agree with the proposed VoLL values and the phased approach to implementing this parameter? *Please provide your rationale and, if 'No', please provide your proposed VoLL value(s) and/or your proposed timescales for phasing this parameter in (if applicable).*
The Workgroup invites you to give your views using the response form in Attachment B

It was queried whether there should be different VoLL values for Demand Disconnection, which consumers would notice, and Voltage Reduction, which consumers likely wouldn't. However, it would be very difficult to disentangle the two types of event as DSOs tend to use both in parallel to achieve a Demand Control action. In any event, it was questioned how a value for each type would be derived, and members felt there would be no advantage over the proposed approach of a single VoLL value. The Ofgem Representatives noted that the value proposed under P305 was lower than the 'true' average VoLL value of £17,000/MWh, and accounts for this value applying to both Voltage Reduction and Demand Disconnection events.

How should revisions to the VoLL value be made?

There has been significant discussion amongst the Workgroup as to how future changes to the VoLL value should be raised.

The Proposer originally proposed that the VoLL value would be as prescribed in the BSC (and subject to the usual Modification process), or as directed by the Authority. The Workgroup proposed an alternative where the value is subject to the BSC process, as proposed, but that the Panel could initiate a review of the VoLL level.

Following constructive discussions between the Workgroup and the Ofgem Representatives on the principles that industry and Ofgem would like to see followed for a future review process, the Proposer has adopted the alternative proposal as part of their Proposed Modification, but with explicit reference to the Authority being able to request the Panel to initiate a review of VoLL, and that any evidence or issues set out by the Authority will be duly considered.

Authority direction

The original proposal giving effect to the conclusions of Ofgem's Final Policy Decision was that the VoLL value should be prescribed in the BSC, and subject to the usual Modification process, but that the Authority should have the ability to bring about a change to the VoLL value, which would then take effect at a time to be determined, superseding the value currently in the BSC.

The Ofgem Representative noted both the value in having this parameter 'hard-wired' into the BSC, but also that there should be an appropriate process for Authority involvement in assessing future changes to the VoLL value, noting the values proposed were derived from a study performed for the Department of Energy and Climate Change (DECC) and Ofgem. There should be an appropriate mechanism to initiate change so that the value that consumers place on electricity is appropriately reflected in the market arrangements

The Workgroup was in agreement that the VoLL value should be hard-wired into the BSC and that changes can be proposed by anyone eligible to do so via a Modification. However, the Workgroup was strongly against the idea of the Authority directing changes to the VoLL value. The Ofgem Representatives on the Workgroup noted that the ability to bring about a change to the VoLL value formed a part of the Final Policy Decision and that the Proposed Modification should be consistent with this. However, they noted the Workgroup's concerns and so worked with members to explore alternative options that could be put forward.

Workgroup members considered that, should the Authority direct a change to the VoLL value, such a change should have a minimum lead time before it could come into effect, to allow the industry time to react and prepare for the change. Members were concerned that a value could otherwise be introduced with a very short lead time. One Workgroup member considered that a period of 24 months would be preferable, but most Workgroup members felt that 12 months would be sufficient if a lead time was to be mandated for any Authority-directed change to the VoLL value.

Members were keen to ensure that a process was put in place for any changes to the VoLL value, to ensure the industry has the opportunity to respond to the proposal before a final decision is made. The Ofgem Representatives noted that in reaching any such decision the Authority would be subject to the usual public law requirements in relation to procedural unfairness, including in relation to adequate consultation. However, it was noted that there were concerns around placing obligations on the Authority in this way. Members felt that submitting all proposals through the BSC Modifications process would be the most suitable route for ensuring they could be fully assessed and consulted upon.

Following the further discussions on this area detailed below, the Proposer, with Ofgem's consent, elected to remove the ability for the Authority to direct a change to the prevailing VoLL value from the Proposed Modification and replace it with the VoLL review process discussed below, which the Authority could feed into.

Potential amendments to the original proposal

Members considered an alternative solution where the Authority could direct the Transmission Company to raise a Modification to progress a change to the VoLL value. This would allow the Authority to direct a change to the VoLL value and ensure industry engagement and consultation through the Modification process, which one member felt would also be more transparent than an Authority-led consultation. The Ofgem Representatives noted there was a risk that this proposal could require a change to the Transmission Company's licence, which could impact the timeline for P305.

One member suggested the option where the Authority could request that the Panel raise a Modification. As the BSC sits under the licence, this could be implemented simply through suitable wording in the BSC. The Ofgem Representatives raised concerns whether it could introduce a discrepancy between the licence and the BSC.

One member considered that the Authority could raise an SCR if it felt a new VoLL value needed to be explored, which already allows it to direct a Modification be raised. They considered that a change to the VoLL value would be a significant change that would require holistic consideration of the impact across the market, which is the intent of an SCR. The Ofgem Representatives noted involvement was only suggested in the VoLL value, and considered the SCR process may not always be appropriate for this purpose.

The Workgroup considered several other parameters under the BSC where the Authority is required to approve changes. However, none of these parameters allows for the Authority to direct a change, only to approve or reject a change following a BSC-led review.

Workgroup members were concerned that allowing the VoLL value to be changed by Authority direction could create precedence for Authority-directed parameter changes, and were keen to avoid this. They agreed that the VoLL value would be an important parameter which would affect forward prices, and that safeguards were required around changes to this value. A thorough review would be required on any changes due to the impacts on the imbalance price.

The Proposer noted that the Authority direction to raise P305 specified that provision must be included to allow the Authority discretion to direct a change. A Workgroup member considered that the approval of a Modification would constitute a direction to the industry, and felt that allowing the Authority to direct a Modification to be raised would therefore be in keeping with the SCR direction. They were concerned that giving the Authority the power to direct changes to a Code would undermine the independence of the Codes. They noted that the BSC was set up as an inter-Party agreement and that the SCR, while Authority-led, is required to be progressed via a Modification to allow for industry assessment and engagement. Another member also had reservations with the Authority raising Modifications without prior discussion with the industry, as it would have the ability to raise and subsequently approve a change, noting that this was the reason why the SCR Modification provisions had been introduced into the BSC. Other Workgroup members did not believe that a BSC Party couldn't be relied upon to voluntarily raise a Modification should a change to the value of VoLL become evidently required.

Overall, Workgroup members noted the points raised by the Ofgem Representatives regarding these proposed alternative options for an Authority-led change to the VoLL value, and elected not to progress them any further.

VoLL review process

The Ofgem Representatives proposed an alternative option whereby a BSC Issue or similar could be raised upon request of the Authority to look at a revised VoLL value, which would take into account any evidence presented by the Authority. Consultation with the industry would take place as part of this, and the Issue Report would form the basis of a recommendation from the Panel to the Authority on whether a change should be made. Workgroup members considered this, and considered that this could resolve some of its concerns.

Members considered that a better approach would be to put in place a review process similar to that currently undertaken for the Market Index Definition Statement (MIDS). Under this approach, the Panel could initiate a review at any time, or upon the request of the Authority. The review would include consultation with the industry, and at the end of the review, if a recommendation to change the VoLL value was made then the Panel would have the power to raise a Modification to make the change. It would be expected, though not stipulated or mandated to avoid fettering the Panel's discretion, that such a Modification would progress straight to the Report Phase with a recommendation to approve. The lead time for any change would be determined under the review and reflected in the Modification. The high-level process and the key points would be contained under the BSC, with the detail either contained in a CSD (potentially a new BSC Procedure (BSCP)) or left for the Panel to determine. It would also be able to delegate this responsibility, most likely to the Imbalance Settlement Group (ISG) or a new group formed specifically for VoLL reviews. Again, this approach would not preclude any BSC Party from raising a Modification of its own at any time to propose its own revised VoLL value.

It was noted that the Authority would be able to request the Panel to initiate a review at any time. The Ofgem Representatives requested explicit reference that the Authority could ask the Panel to initiate a review should be included for clarity, amid concerns that the Panel may refuse such a request. Workgroup members were confident that this would not happen, and could not see why it would, but agreed that this clarity should be included. Members considered that if the Authority had a particular VoLL value in mind when a review was initiated it should feed that into the review, and should not reject the outcome of a review in favour of a different value. It was highlighted that the Authority could send a representative to attend and participate at any meeting held under the BSC.

Some members queried whether there should be a maximum interval between reviews, feeling this would provide more certainty to participants, and would make it more likely that resulting changes to the value would be small and would not surprise participants. It was proposed that a review should take place at least annually, to provide visibility to participants on when a change to the VoLL value may come, and highlighted that a review could recommend that no change be made. It would also help to flag to new participants the presence of the VoLL value. However, most members could not see the benefits in this, feeling that it was 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 changes would likely be more significant in response to changes in the prevailing market conditions.

Assessment Consultation Question
Do you believe that a maximum interval between VoLL reviews should be implemented? *Please provide your rationale and, if 'Yes', please state what maximum interval you believe should be implemented.*
The Workgroup invites you to give your views using the response form in Attachment B

A member also proposed that a minimum lead time should be applied to any change arising from a review, and suggested this be set to six months. However, it was felt more appropriate to allow the review to determine the most appropriate lead time, and that this could be a barrier should an urgent reduction in the VoLL value be identified as necessary. In any event, a participant could circumnavigate a fixed minimum lead time with their own Modification Proposal, which would not be subject to any minimum lead time.

Overall, the Workgroup agreed that the VoLL review process:

- would be initiated by the Panel from time to time or upon the request of the Authority, with no maximum period between reviews;
- would allow the Authority to contribute its views to the review;
- would include consultation with the industry; and
- would allow the Panel to raise a corresponding Modification if the review recommended a change be progressed, with no minimum lead time on any change.

The Proposer noted the Workgroup's support for the VoLL review process and therefore elected to adopt this process in place of the Authority's ability to direct a change to the VoLL value. The Ofgem Representatives were content with this amendment.

Should the VoLL value increase in line with inflation?

The Workgroup also considered whether the VoLL value should be automatically increased each year in line with inflation. A proposal was made that this could increase every April in line with the Consumer Price Index (CPI) value in the preceding January, giving participants three months to prepare. However, members noted that the values were an administrative value to act as a proxy to reality and so did not need to account for inflation. Several members also expressed views that the values put forward under P305 were high enough already, and felt further increases in line with inflation were unnecessary. It was highlighted that the DECC-Ofgem study on the Value of Lost Load for GB consumers suggested an average VoLL of £17,000/MWh, notably more than the ultimate value of £6,000/MWh proposed by P305. The Workgroup agreed that if the VoLL value was deemed inappropriate or no longer right at a later date then a Modification could be raised to review this and propose a revised value, and could be progressed as an Urgent Modification if it was felt necessary. One member was adverse to the step-change in the VoLL value that was being proposed, and preferred that it be indexed on a regular basis instead. However, other members believed that the proposed values were appropriate, noting that the initial value of £3,000/MWh would allow the industry to get used to the VoLL value.

It was queried whether the VoLL value could be seen as a cap on prices. The Ofgem Representatives confirmed this was not the intent, and a Workgroup member flagged that it could be exceeded by a high-priced BOA, noting that Bids and Offers can currently go as high as £99,999/MWh.

Which type of Demand Control events should fall under P305?

The Workgroup noted that Demand Disconnection and Voltage Reduction events had been put forward as events that should be accounted for by P305, but that the EBSCR had left automatic LFDD events open for it to consider. It was noted that an action had to be deemed an energy balancing action in order to affect the imbalance price, as system balancing actions would be unpriced as part of the calculation. Members considered that LFDD actions should be considered a type of system balancing action, as they would be undertaken by the Transmission Company, potentially automatically, to maintain the frequency of the system within the statutory limits. Participants should not be penalised for actions taken by the Transmission Company to meet its statutory obligations, and which participants cannot forecast.

The Workgroup considered the notifications that would be published for Demand Control events, noting that they would contain the start and end times of the event. It was agreed that these notifications should be updated whenever further instructions were made by the Transmission Company to distributors, and that the most practical volume to report would be the volume instructed by the Transmission Company. All notifications would be published on the BMRS.

The Transmission Company noted that it would seek to provide all Demand Control notifications within 15 minutes, but due to the manual nature of instructing Demand Control and that the control room would be more focused on managing the situation, this would be met on a 'reasonable endeavours' basis. The Workgroup was content with this approach. One member was concerned that if a notification came in too late it may not be included in the indicative imbalance prices published on the BMRS 15 minutes after a Settlement Period, and queried whether an ad-hoc revision could be made to the published prices in those circumstances. This is to be investigated.

Members queried the shape of a Demand Control event profile that would be calculated under the 'top-down' method, which would be based on these notifications. It was highlighted that this would be a high-level estimate based on the volumes requested by the Transmission Company, and not the volume actually delivered. Although in reality there would be a 'ramp-rate' where demand is removed or subsequently returned, it would be difficult to factor this in to the calculation, but as this would be a high-level estimate this would be unlikely to have a material effect. It was also considered that in most events the Transmission Company would end all instructions close to simultaneously, and that simultaneous termination could be assumed for the purpose of profiling the disconnected volume, although for some larger events it may seek to terminate instructions in a more staggered approach for safety reasons.

One member was concerned about the impact of 'negative demand' and whether this may have unintended consequences on the estimate of the volume. The DSO may disconnect a part of its network that contains exporting Meter Point Administration Numbers (MPANs), which may reduce the total volume that is disconnected. Another member noted that if a DSO had been asked to disconnect a certain volume then it would be expected to deliver that volume, and that it should have accounted for any potential exporting MPANs when deciding which areas to disconnect. The 'top-down' estimate would be based on instructed volume and not delivered volume. The first member was still concerned that any impacts of 'negative demand' could result in an over-estimate of the volume being submitted into the imbalance price calculation. Another member felt that this was a question that could never be answered as it would never be known for sure what actually happened.

Members queried how directly connected sites and Interconnectors would be used in a Demand Control event. The Grid Code obligates directly connected sites to have disconnection capability, and that it would be for the Transmission Company to determine the cost of disconnecting that site, which would essentially be equivalent to an Offer. It was agreed these sites need to be identified and included in the imbalance position correction process proposed under P305. Interconnectors are deemed part of the Transmission System, and rules are in place at a European Union level about when and how an SO can disconnect an Interconnector connected to their Total System. One member thought that should an Interconnector be exporting at a time of high LoLP then that would suggest prices were also high in the market on the other side of the Interconnector, as a consequence of market coupling. It was noted that the Transmission Company could issue a SO-SO instruction if necessary, although this would not be captured in the imbalance price calculation.

Can Voltage Reduction events be included in the 'bottom-up' calculation?

The Workgroup noted the Authority's request to it in the direction that it consider whether the 'bottom-up' volume correction process for Demand Disconnection events can also be applied to Voltage Reduction events. This had been discussed under the SCR's Technical Working Group (TWG), but this group had not been able to develop a solution, electing to leave it to the P305 Workgroup to consider.

One member queried how a Voltage Reduction event could be measured, or what would be being measured. For a Demand Disconnection event an MPAN's volume can be assumed to be zero during the affected period. This would not be the case for an MPAN subject to a Voltage Reduction event. Members could not put forward any viable options for estimating a volume for a Voltage Reduction event, feeling that input would be required from experts such as DSOs, who were not present on the P305 Workgroup. It was noted that Grid Code Modification GC0050 'Demand Control (OC6)' had looked at areas related to Voltage Reduction, and that any output from that group should be considered. However, it was also noted that results from a Voltage Reduction event could vary wildly for the same instructed volume.

The Workgroup agreed that, given the work that it believed would be required to develop a process to produce a 'bottom-up' estimate for Voltage Reduction events, and given the timescales for P305, the question should be considered separately, most likely under a BSC Issue. Any solution that was developed would then be progressed and implemented via a separate Modification. The process required for correcting volumes developed under P305 would work for Voltage Reduction events as well as Demand Disconnection events, so once a method for estimating the volumes had been produced, the rest of the process developed under P305 could be utilised with little subsequent amendment.

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.

How should the 'bottom-up' calculation work?

The Workgroup has considered the detail of the 'bottom-up' calculation for correcting participants' imbalance positions following a Demand Control event.

One Workgroup member highlighted that this area has been considered in the past, most recently under P199 'Quantification of Demand Control in the BSC as instructed under OC.6 (c),(d) & (e) of the Grid Code', which was rejected by the Authority in 2006 as it was felt that the proposed process of allocating the correct volumes to the correct participants was not sufficiently accurate. The member was concerned that the same issue could occur with the calculation proposed under P305. They could see the case for a single marginal imbalance price and for the pricing of reserve actions, but were worried that the process for correcting imbalance volumes may cause the entirety of P305 to be rejected if it was not correct. It was believed that this would not be an issue in a fully HH settled market, as the main issues are with the correction of NHH volumes, but it will be many years before such a market can be realised.

What is the impact on DSOs and Supplier Agents?

Although not impacted by the consequences of P305, DSOs and Supplier Agents would be involved in the 'bottom-up' calculation for the Demand Control volume. DSOs would be required to identify the impacted MPANs, after which Supplier Agents would calculate the impacted volume for each of their Suppliers to allow their imbalance positions to be accounted for. This is a relatively small impact in the scale of both P305 and other, wider industry changes, and so no DSO or Supplier Agent representatives elected to join the

P305 Workgroup. While they had not joined Ofgem's TWG under the SCR either, Ofgem had worked closely with them in developing the EBSCR proposals. The views and impacts on these participants have also been gained through responses to the P305 Impact Assessment and with conversations with these participants directly or through other forums such as the Software Technical Advisory Group (STAG).

A key area noted by these participants was the highly automated nature of the Data Aggregator roles. Data Aggregators disagreed with the Workgroup's proposal in the Impact Assessment that the lists of impacted MPANs should be sent from DSOs to Supplier Agents via a spreadsheet. They felt this could be too unstructured, and would not easily allow for automatic loading of the MPANs into the Data Aggregator systems. They preferred that this information was submitted via a DTC flow. This will now be the case.

As part of its discussions of the proposed solution, the Workgroup also considered the other flows by which Demand Control related information would be submitted. It was believed that it would generally be easier, and likely cheaper, to create new Demand Control specific DTC flows to be sent alongside the existing flows, rather than amend the existing flows to contain new fields and information. This would also make it easier to distinguish 'actual' volumes from those affected by the imbalance position correction processes.

How should voluntary actions be accounted for?

Members noted that it is possible for some MPANs in a Demand Control area to have already reduced their consumption in response to voluntary actions, for example under a DSBR request. These MPANs should therefore be identified as part of the imbalance position correction process to ensure they are not 'double-counted' by the process.

In its Impact Assessment response, the Transmission Company noted that it would not be able to provide the MPANs impacted by a DSBR instruction until after the SF Settlement Run, as this is how long it would take for Supplier Agents to complete the necessary processes introduced under P299 'Allow National Grid access to Metering System Metered Consumption data to support the DSBR service'. Furthermore, it would not be able to provide the details of non-BM STOR instructions at anything more granular than at BM Unit level. This is because in both cases the Transmission Company would issue its instruction against a portfolio of MPANs, and the recipient of the instruction would determine which MPANs within the portfolio would be affected to discharge the instruction. The Workgroup was surprised at this, but noted that receiving the data at a BM Unit level would be sufficient for the imbalance position correction process.

It should also be noted that any changes required to obtain information on MPANs that have reduced volume under the CM for use in this process would need to be progressed through the EMR change processes, which may ultimately require approval from the Secretary of State.

How should NHH Suppliers' imbalance positions be adjusted?

The Workgroup considered several options for correcting NHH Suppliers' imbalance positions as part of the 'bottom-up' process, and you can find the details of these in the industry Impact Assessment available on the P305 page of our website. These options put forward several methods of different complexity, but also different levels of accuracy for the redistribution of the estimated disconnection volume across impacted Suppliers.

However, all of the options considered were designed to remove the issues around applying Grid Supply Point (GSP) Group Correction Factors within the correction process. It was also noted that one option would remove the involvement of Supplier Agents from this part of the process, although this would likely be the least accurate of the methods.

Following conversations with Supplier Agents, the Workgroup has proposed a revised method for correcting NHH Suppliers' imbalance volumes following a Demand Control event. It believes that this method would be both cheaper to implement and operate and also more accurate than any of the three options it proposed in the Impact Assessment. The requirements for this process can be found in Attachment A (specifically Requirement D8). The Workgroup seeks the views of participants on this revised method as part of this Assessment Procedure Consultation.

Assessment Consultation Question
Do you agree with the proposed approach to correcting NHH Suppliers' imbalance volumes following a Demand Control event? *Please provide your rationale and, if 'No', please state what you disagree with and what approach you would prefer was followed instead.*
The Workgroup invites you to give your views using the response form in Attachment B

How accurate does the process need to be?

Members discussed whether the more complex 'bottom-up' approach was required or whether the simpler 'top-down' approach could be adapted for use in its place. However, it was noted that the 'top-down' approach does not provide sufficient granularity to allow the total volume to be adequately distributed among impacted participants, and so this was disregarded as an option.

It was highlighted that the 'bottom-up' calculation needed to be as accurate as possible, noting that the concept of accuracy with this process was in relation to the accurate allocation of the estimated Demand Control volume between the impacted participants, as it was felt the true total volume could never be known for certain. Settlement Periods in which the 'bottom-up' calculation would be used would likely be Settlement Periods where the imbalance price would be set to the VoLL value, which would have a significant impact on participants. Assuming a VoLL value of £6,000/MWh, it would only require a Demand Control event of around 170MWh for the total materiality to exceed £1m, and events, should they occur, are likely to be several times that size. If any adversely impacted participant felt that the calculation for correcting its volumes were wrong or unfair, it could cause a lot of scrutiny to be turned on the process.

One member considered whether there was a risk of developing a complex and expensive process for an event that may rarely or never take place. It was noted that there have only been two Demand Control events in the last few years, but that the Secretary of State was forecasting as many as three per year in coming years, meaning that this process could be called upon relatively frequently. Having a sufficiently accurate process with sufficient assurance around it would also set expectations of what would happen following a Demand Control event, especially for participants who may find themselves short as a result of the event. It was also noted that without a correction process there could be a risk of 'gaming' should participants seek to "bust the system" in order to "chase the imbalance price". In any event, the incentive on participants should be to avoid Demand

Control events occurring at all. It was also noted that payments to Suppliers and consumers had been proposed during the consultation for the EBSCR Draft Policy Decision, and was removed from the scope following this.

Should participants' positions be corrected?

One member noted the complexity involved with correcting participants' positions, and wondered if it was even necessary with the move towards Time of Use tariffs. They considered that a Demand Control event could be seen by the European Union as a form of Offer made by the consumer, and that the volume should be calculated before then being treated as an Offer. They also considered a participant who may have made an expensive trade at the day-ahead stage in reaction to a high Indicative LoLP value before perfectly balancing their position, only for their consumers to be disconnected. The participant's resultant position would therefore be a long one, which would be adjusted back by the process. However, as their customer would not have consumed, the participant would be left with the cost of their expensive trade. They believed the participant's position should be left long and the subsequent windfall from their imbalance position treated as compensation.

Other members were not convinced by this argument, noting that each participant adopts different trading strategies. In this scenario, the only 'missing money' would be a few hours of consumption being removed from the customer's bill, which would likely be a very small volume. It was also flagged that without the correction, there was a risk that participants may "chase the imbalance price" in an attempt to profit, which would exacerbate the situation.

Should the 'bottom-up' volume be used in the price calculation?

The EBSCR Final Policy Decision put forward the solution that the 'top-down' estimate of the volume of instructed Demand Control actions would be used for the BMRS indicative imbalance prices published 15 minutes after the end of the Settlement Period and in the Interim Information Settlement Run (II). This would be based on the volume instructed by the Transmission Company. The 'bottom-up' estimate, calculated using actual data, would be used instead from the SF Settlement Run onwards. This was proposed as it was felt this would allow a more accurate volume to be included in the calculation when it became available.

Workgroup members noted that this approach is different to that taken for other types of instructions. In particular, it was noted that BOAs are inserted into the imbalance price calculation using the volume instructed by the Transmission Company. This volume is used throughout all Settlement Runs for calculating the imbalance prices, with no attempt made to calculate the volume that was actually delivered. Members believed it would be more consistent to apply this principle to Demand Control actions too and therefore to use the 'top-down' volume at all Settlement Runs. This would also prevent the volumes from changing significantly from one Settlement Run to the next, which could cause a significant change in the imbalance price for that Settlement Period, and would create uncertainty to what the imbalance price is prior to the SF Settlement Run.

The Proposer agreed with the Workgroup's views on this area, and adopted the Workgroup's proposal into its proposed solution, meaning that the 'top-down' volume would be used at all Settlement Runs.

Members queried how the Demand Control volumes would be entered into the stacks. Instructions would be issued to DSOs in stages, with each stage being aimed at particular GSP Groups. However, as the volume would be priced into the imbalance price calculation at the VoLL value, it was deemed easier to enter a single action per Settlement Period consisting of the total instructed volume applicable to that Settlement Period, rather than split it down by GSP Group or similar. It was noted that the details of all instructions would be published on the BMRS individually, and so it would not decrease transparency to aggregate the volumes in the imbalance price calculation.

One Workgroup member queried what would happen if a Demand Control impacted Settlement Period were to form a Triad period. It was felt that such a Settlement Period was unlikely to form a Triad period, and also that the intent of the correction process is only to correct imbalance positions, with the actual volumes delivered being used elsewhere.

Should other parameters be considered?

One member noted that the CADL is currently set to 15 minutes, meaning that any action that lasts for less than 15 minutes would be CADL-tagged and subsequently unpriced as part of the imbalance price calculation as it would be deemed a form of system balancing action. This would mean that if a Demand Control event occurred for less than 15 minutes then it would not affect the imbalance price.

The member also queried whether imbalance positions should be corrected in Settlement Periods where the Demand Control volume is subject to CADL-tagging. Other Workgroup members believed positions should still be corrected in this scenario as prices would still likely be high, and not correcting in CADL-tagged Settlement Periods may cause the situation where positions are corrected for some events and not for others, which could result in an uneven playing field.

Another member also noted that an expensive action taken by the Transmission Company on account of a fast ramp-up rate could have the potential to set the price if the duration lasted for more than 15 minutes. Furthermore, it is possible that the generation unit may have been instructed for 15 minutes, and so would be CADL-tagged, but overran slightly, meaning it would not be CADL-tagged. Should this action then straddle two Settlement Periods it could end up setting the imbalance price in both Settlement Periods when in reality it should have been tagged out of the calculation. However, it was unclear how this scenario could be resolved. Other members felt that an action of this nature would likely be deemed a system action and would be flagged accordingly.

What impacts could P305 have on credit?

Members were concerned on the impacts that P305 may have under the credit arrangements. It was noted that several other Modifications have been or are being progressed, notably P306 'Expanding the definition of a 'Letter of Credit' to include regulated insurance companies', P307 'Amendments to Credit Default arrangements' and P308 'Alternative security product for securing credit under the BSC', which would amend the credit arrangements in different ways. However, Modifications cannot be contingent on each other, and so P305 cannot be made contingent on the outcomes of these other changes, but it was felt that P305 would have a direct impact on credit. Members therefore felt that the implications of P305 on participants' Credit Cover needed to be highlighted.

EBSCR Credit Cover analysis

Baringa's forward modelling for Ofgem carried out under the EBSCR simulated Credit Cover impacts, available as part of the Final Policy Decision, in particular:

- Baringa's Further Analysis to Support Ofgem's updated Impact Assessment 2014 p53 & p65
- EBSCR Final Policy Decision Impact Assessment 2014 Chapter 4

A concern was raised that corrected imbalance volumes arising from the 'bottom-up' calculation would not be available before the SF Settlement Run, which could cause participants' positions at the II Settlement Run to be too long. This could mask a participant's true position up until this point, giving it a false sense of security as its position would be underestimated.

Assessment Consultation Question
What impacts do you believe P305 will have on the BSC credit arrangements? *Please provide your response and rationale.*
The Workgroup invites you to give your views using the response form in Attachment B

What analysis has been undertaken?

Ofgem's SCR analysis

The Ofgem Representatives urged the Workgroup and other participants to read and digest the analysis that had been undertaken by Ofgem under the EBSCR. They also presented an overview of the approach taken in developing the evidence base over the last four years, and the issue and rationale for reform, as well as responding to specific Workgroup queries. The presentation highlighted that the evidence base had been driven by qualitative analysis of proposals, stress-tested by extensive quantitative analysis (including forward modelling, historic modelling and a commissioned study) and subjected to further stress-testing through consultation with stakeholders.

One member was concerned that the analysis had not gone far enough in determining the distributional effects that the EBSCR would have, highlighting the significant effects that had been revealed under P304. However, it should be noted that the P304 analysis was based on analysis of historical data whereas the SCR analysis included both forward-looking modelling that aimed to take into account behavioural changes (the impetus for reform) as well as historical analysis.

The Ofgem Representatives noted that economic theory is the key driver for the reforms, to ensure that the incentives for Parties to manage their imbalance positions aligned with the consumer interest, and the analysis and modelling draws upon this theory. One finding had been that bigger Parties are more exposed to the risk of driving a large net imbalance volume, and so according to their imbalance performance could be more impacted by the reforms and see less benefit from a single price. Conversely, smaller Parties are less likely to drive the net imbalance volume, more likely to enjoy the more favourable single price on opposite imbalances, and on average are less impacted. Furthermore, Parties who are better able to forecast positions will benefit more. The Ofgem Representatives noted that the SCR process had been evidence-based, and had been developed and consulted upon over a number of years, providing qualitative narrative informed by the findings of the quantitative analysis that could fulfil the Workgroup's Terms of Reference. They felt that the question of whether the SCR forward modelling should be revised or expanded was a balance between the benefits of seeing the results versus the cost of extending the analysis and the time this would take. They noted that to form a view against the Applicable BSC Objectives it is not necessary to understand the precise financial implications for every BSC Party, as well as noting the risk that modelling at individual Party level presents spurious accuracy. It was noted that re-running the model to show

EBSCR analysis

The full suite of analysis undertaken by Ofgem under the EBSCR can be found as part of the EBSCR Final Policy Decision.

impacts at individual Party level would cost around £50k-£75k and take around two to three months to complete. The Ofgem Representatives felt overall the costs of re-running the model would outweigh the value it would provide, and the Workgroup agreed that no further work should be undertaken with Ofgem's forward modelling analysis.

The member felt they needed to understand the economic theory more, but stressed that the Workgroup needed to be satisfied that any unintended consequences arising from it would not be of a magnitude to cause significant harm to competition, and felt that the impacts only become clear when they are broken down over sufficiently granular subsets of participants. Another member noted that historical analysis is the only factual form of analysis available, and that anything else is based on assumptions. The Ofgem Representatives responded that if the EBSCR conclusions had been implemented several years ago, the behaviour of participants today would be very different to what it currently is, meaning that historical analysis is built on an assumption that Parties do not change behaviours in response to changed incentives. It was also noted that Ofgem's historical analysis had suggested that, on average, the SBP would be about £10/MWh higher under the EBSCR arrangements than the current arrangements.

A member was concerned to understand the impact on a Party-by-Party basis, noting that some participants would be new, with little historical data available, or may have chosen to trade through another Party, and that these would be hard to model. Another member highlighted that, while many people were focused on the potentially detrimental impacts that smaller Suppliers may face, independent generators are just as much at risk should they suffer an unplanned outage at the wrong time. The Ofgem Representatives noted it was not the Workgroup's role to assess the impacts on every individual Party but to draw out the overall efficiency and competition impacts, noting behaviour change as the key impetus for reform, highlighting the importance of forecasting demand, maintaining plant, striking contracts for Demand Side Response (DSR) or other flexibility capacity providers, adjusting hedging strategies and developing strategies to deal with wind forecast error correlation. They urged the Workgroup to read the EBSCR reports and analysis in detail as it goes into more detail on these themes.

A member queried the finding from the historical analysis and forward modelling that larger Parties drive the price and so smaller Parties would be less impacted. They asked to see a correlation on prices and the volumes in participants' Consumption Energy Accounts, which may challenge that assertion.

Members noted that participants would always want to know the impact of any change on their own organisation. It was also flagged that if the analysis is not done at a Party level then there could be an odd Party adversely impacted due to a very specific but perfectly valid trading or business model, and that the electricity market is one where smaller players can be quite niche. Furthermore, while the changes may make sense economically there will still be winners and losers. If this change was going to jeopardise participants, they would want as much notice of this as possible to prepare. However, it was noted that all the benefits of the EBSCR would be realised through behavioural change, and that if participants did not change their behaviour then they would likely lose out. The Ofgem Representatives also queried how the identification of impact at Party level supported an efficient process.

One member noted that the forward modelling undertaken by Ofgem had assumed rational behaviour by participants, but felt that this may not be the case in reality. They queried whether a sense-check had been undertaken by Ofgem, for example speaking to smaller participants on what they could do in a given situation compared to what they would ideally like to have done. In many situations, it may be that the options available to the participant are not the options it would ideally like to take, such as in response to a signal of high prices occurring very close to real time with little time in which to react. This situation can be exacerbated if the participant cannot access credit or be able to adequately trade its position, and the member felt that imbalance prices can be penal to these participants if the relevant tools are not available to them. The Ofgem Representatives noted that it is hard to model irrationality, but that the assumption of no behaviour change is not particularly helpful for shedding light on a policy with behaviour change as its key motivation. They also noted the combination of forward analysis (assuming rationality) and historical analysis (assuming no rational change in behaviour) helps to inform the range of potential effects. More generally, the Ofgem Representatives noted that their policy had been developed over a number of years in consultation with a broad range of Parties. This has allowed views of a variety of Parties to be represented in consultation responses and considered in development of policy.

The Workgroup considered the conclusions that prices would be much higher in the future, noting that this was largely due to the forecasted increase in intermittent generation. It was asked how high imbalance prices would have to go to sufficiently incentivise participants to invest in new technology. The Ofgem Representatives highlighted that investment effects had been very difficult to assess, and as a result the modelling had not captured all the dynamic efficiency benefits of driving a more efficient flexible generation mix. They noted however that allowing prices to better reflect the cost to the consumer of the SO's balancing actions is key in supporting efficient investment and dispatch in flexible capacity. It was also noted by a member that data relating to carbon prices that Ofgem had used in its model had since been updated, and felt the model should be redone with this updated information. The Ofgem Representatives felt this would not support an efficient process, noting that it would be unlikely to affect the relative differences between the EBSCR and do-nothing scenarios, and that the information could change again while this was taking place. Another member noted that the key consideration was the relative difference in prices should the EBSCR conclusions be implemented compared to no change, and flagged that the model was showing that, for most participants, the costs would be lower under the former, indicating that the EBSCR conclusions would be better than doing nothing. It was also felt that, while it may not be possible to see what new innovations could be developed over the next decade at this point in time, this did not mean things would not be developed going forward. One member felt that there would always be something participants could do to avoid being in imbalance.

Members highlighted that liquidity in the electricity market is not as high as was originally envisioned when the current arrangements were introduced in 2001. There was a concern that a single price may have a negative impact on liquidity, especially in the intra-day market. Other members noted the intra-day market had not been identified as a source of concern, and that the Secure & Promote requirements drive liquidity further along the curve. The Ofgem Representatives noted that liquidity effects had been discussed in consultation and analysed over the years of EBSCR analysis, and that the TWG had discussed liquidity but had been unable to determine how this could be meaningfully modelled.

One member asked what measures had been considered if, following implementation of P305, many participants were forced to exit the market due to a significant spike in imbalance prices. Another member felt that such an event would likely cause a domino effect, as the counterparties to any exiting Party would themselves be impacted. The main concern is whether large prices can be predicted and whether Parties would be able to avoid them, and it was noted that there has been relatively little stress on the Total System over the last few years and so it is hard to foresee what may happen if such a time was experienced. The Ofgem Representatives considered that the phased approach of implementing the full EBSCR solution would help mitigate such an effect, and felt that this change had been signposted for a sufficiently long enough period of time for participants to make preparations.

ELEXON's analysis for the Workgroup

A Workgroup member noted that while Ofgem had done a significant amount of analysis under the EBSCR, the Workgroup had been charged with doing further analysis as it saw fit to assess the impacts of P305. This could include endorsing Ofgem's analysis, but did not preclude the Workgroup from doing its own. The Ofgem Representatives did not disagree with this, but emphasised that any analysis undertaken should be done on a pragmatic basis, in particular to inform assessment against the Applicable BSC Objectives.

Some Workgroup members were keen to undertake historical analysis of recent years with the P305 arrangements in place. Other members were unsure what this would show, noting that participants' behaviour would have been different in a single price regime and so whatever such analysis produced would be wrong. The Ofgem Representatives were also unsure of the merits of performing additional historical analysis, particularly given that the intent of the EBSCR is to drive behavioural changes. However, participants in favour suggested that this would show the worst-case scenario should participants not change their behaviour in response to P305. It would also allow distributional effects to be assessed, and could be used to assess the most suitable PAR value(s) to adopt. It was also felt that the data should be made available to all participants, so that they can assess the impacts on their own organisations for themselves. There was also a view that should ELEXON's analysis support Ofgem's conclusions then this may provide more comfort to participants, while if it does not then this would suggest areas that need to be considered further.

ELEXON is undertaking a comprehensive piece of analysis for the Workgroup, and a summary of the results will be published separately on the P305 page of our website in due course. The Workgroup has been unable to fully consider this analysis prior to this consultation being issued, and so has been unable to draw any conclusions from it.

In addition, the raw Party-level data from this analysis will also be available on the ELEXON Portal in due course for participants to download and consider.

Additional areas for consideration

The Workgroup noted that it would be very difficult to assess the potential impacts on intermittent generators, as such impacts are quite difficult to assess through analysis. The Workgroup therefore wishes to obtain information on this area from respondents to the Assessment Procedure Consultation on this area.

It also seeks respondents' views on the interaction that P305 may have with the CM or with Contracts for Difference (CfD).

ELEXON's historical analysis

The results of the historical analysis will be made available on the P305 page of our website in due course.

The raw Party-level data produced by the historical analysis will also be available from the ELEXON Portal in due course.

EBSCR analysis on additional areas

Ofgem's analysis under the EBSCR sought to look at these additional areas, and these can be found in the Final Policy Decision. In particular:

- Baringa's EBSCR Further Analysis to Support Ofgem's Updated Impact Assessment p51-53 & p65-67 outlines the simulated forward-looking impacts on intermittent generators (among others)
- EBSCR Final Policy Decision 2014 p38 and Ofgem's Final Policy Decision Impact Assessment p17-19 looks at the interaction with the CM

Assessment Consultation Question
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? *Please provide your rationale and, if 'Yes', please quantify impacts where possible. Please also identify any other impacts you believe P305 will have on intermittent generators.*
Do you believe that there will be any impact or interaction between P305 and the Capacity Mechanism & Contract for Difference arrangements? *Please provide your rationale and, if 'Yes', please detail what you believe these impacts and interactions would be.*
The Workgroup invites you to give your views using the response form in Attachment B

Workgroup's initial conclusions

At this stage, P305 Workgroup members do not believe they are able to provide their initial views against the Applicable BSC Objectives. They believes they will be better able to provide views once they have seen the industry views and impacts, have had further time to consider the accompanying analysis and have decided upon their preference with respect to a potential Alternative Modification. Therefore, the Workgroup has not put forward an initial recommendation on whether P305 should be approved or rejected.

Proposer's views against the Applicable BSC Objectives

Applicable BSC Objective (b)

The Proposer believes that the changes to the main imbalance price calculation strengthen the incentive on Parties to make efficient balancing decisions, particularly during times of tight margin. This should reduce the cost of achieving balance as borne by the market and the actions taken by the Transmission Company, and support security of supply. This effect may be reinforced as improvements in cost reflectivity further encourage investment decisions and innovations that drive long run cost savings in delivery of any given level of security of supply.

This Modification will also signal the start of reforms designed to better reflect the value of flexible plant in the balancing arrangements. It may therefore contribute to deferring the decommissioning of generation with more flexible capacity and help counteract potential tightening of availability.

The Proposer considers that the stepped nature of implementation should allow time for the industry to adjust to the EBSCR reforms and to change behaviours accordingly.

Applicable BSC Objective (c)

The Proposer considers that current inefficiencies could 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. These reforms are intended to address these inefficiencies and thereby support effective competition (that delivers in the interest of the consumer) by:

- Allowing flexible and reliable plant to gain a competitive advantage that reflects the value provided to the consumer; and
- Improving the incentives for these Parties to enter the market, driving the flexibility and reliability needed to accommodate growing intermittency on the system

The inclusion of a single imbalance price removes the existing inefficient price spread and thereby reduces the net imbalance costs for many Parties, particularly smaller Parties, which would therefore encourage market participation.

The Proposer also believes that strengthening the imbalance price signal as proposed by P305 should incentivise market participants to trade in order to balance their positions ahead of Gate Closure. This should increase liquidity in the forward market and benefit competition by encouraging investment in flexible capacity.

What are the Applicable BSC Objectives?

(a) The efficient discharge by the Transmission Company of the obligations imposed upon it by the Transmission Licence

(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

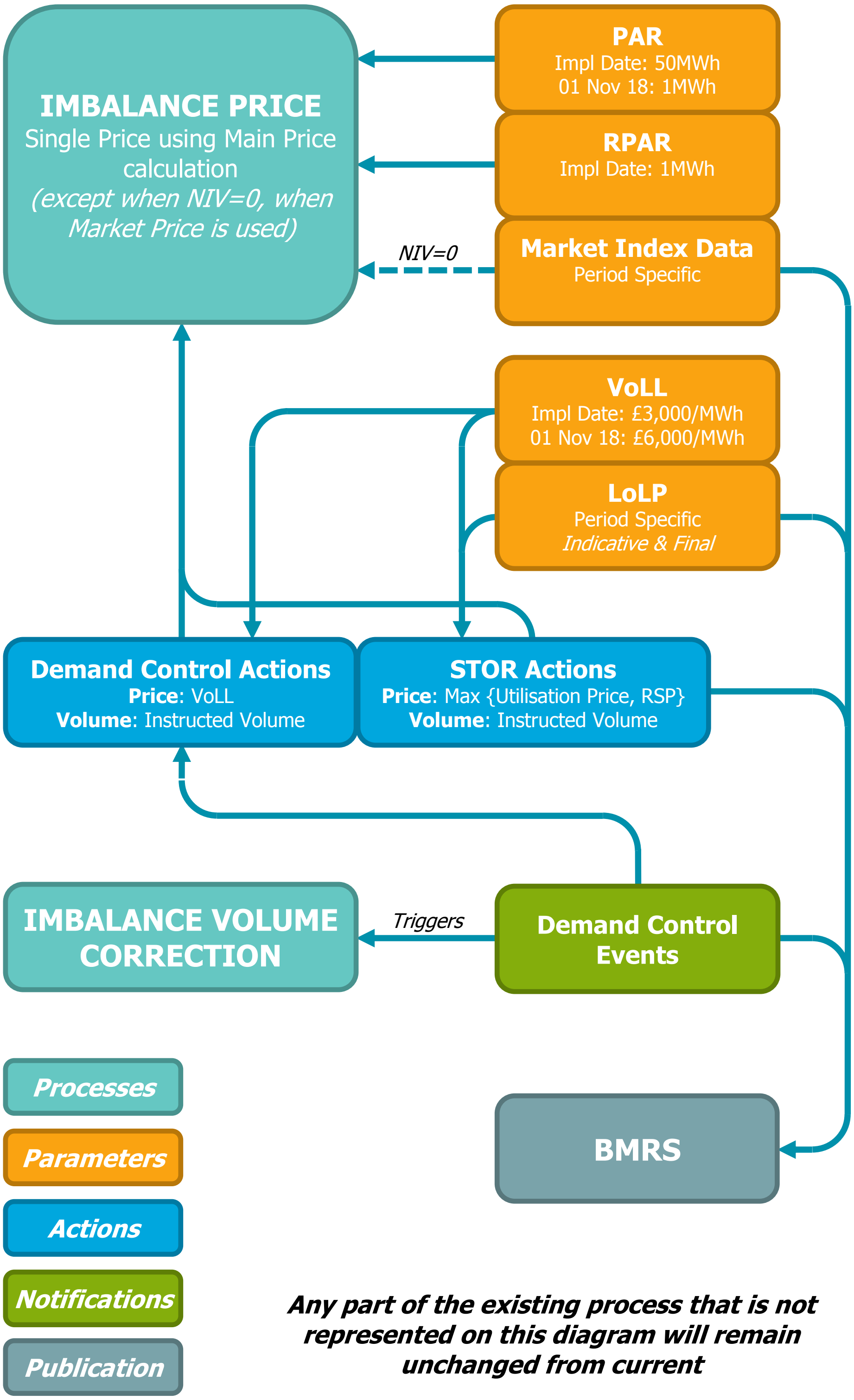
(e) Compliance with the Electricity Regulation and any relevant legally binding decision of the European Commission and/or the Agency [for the Co-operation of Energy Regulators]

(f) Implementing and administrating the arrangements for the operation of contracts for difference and arrangements that facilitate the operation of a capacity market pursuant to EMR legislation

Assessment Consultation Question
Do you believe that P305 would better facilitate the Applicable BSC Objectives and should be approved? *Please provide your rationale with reference to the Applicable BSC Objectives.*
The Workgroup invites you to give your views using the response form in Attachment B

Appendix 1: P305 Solution Summary Diagram

This diagram summarises the impacts and interactions of the P305 proposed solution on the imbalance price calculations. Any part of the existing process not included on this diagram will not be impacted by P305.



Any part of the existing process that is not represented on this diagram will remain unchanged from current

Appendix 2: Workgroup Details

Workgroup's Terms of Reference

Specific areas set by the BSC Panel in the P305 Terms of Reference
Are the proposed solutions the most appropriate way to implement the EBSCR conclusions?
Are the proposed step-changes to the PAR value the most appropriate values?
How should the LoLP value be calculated for each Settlement Period?
Is there a risk of market abuse or manipulation and how can this be mitigated or prevented?
Will a move towards a more marginal price reflect a more marginal cost?
What impact may P305 have on Parties' behaviour and the likely positions they may seek to take following implementation of the changes, and what issues may this cause?
What impact will each aspect of P305 have on different types of users, in particular non-portfolio generators, small Suppliers and intermittent generators?
What are the answers to the questions posed by Ofgem in its draft business rules and how should they be incorporated into the proposed P305 solution? These questions are: • How should the imbalance price be calculated when NIV is zero? • Should Market Index Data and the MIDS be removed, and would there be any wider implications in doing so? • What, if any, input metrics to the LoLP calculation should be published on the BMRS? • How frequently and far in advance of Gate Closure should indicative LoLP values be published? • Should VoLL increase in line with inflation each year? • Should automatic Low Frequency Demand Disconnections be included as a type of Demand Control event? • Is there a more accurate means to correct a Supplier's imbalance position for the II Run than proposed? • Is it feasible to calculate an accurate estimate of the volume of voltage reduction? • How should historic GSP Group Correction Factor data be used in the correction of Suppliers' imbalance positions?
What views and arguments have been expressed under previous Modifications relating to the imbalance prices and do they apply to P305?
The Workgroup should undertake any analysis required to demonstrate the impacts that P305 may have, drawing upon the analysis undertaken under the EBSCR where possible.
Do the changes proposed by P305 have the potential to simplify the imbalance price calculations?
What is the most appropriate Implementation Date for P305?
What changes are needed to BSC documents, systems and processes to support P305 and what are the related costs and lead times?
Are there any Alternative Modifications?
Does P305 better facilitate the Applicable BSC Objectives than the current baseline?

Assessment Procedure timetable

P305 Assessment Timetable	
Event	Date
Panel submits P305 to Assessment Procedure	12 Jun 14
Workgroup Meeting 1	19 Jun 14
Workgroup Meeting 2	18 Jul 14
Workgroup Meeting 3	22 Aug 14
Industry Impact Assessment	05 Sep 14 – 26 Sep 14
Workgroup Meeting 4	10 Sep 14
Workgroup Meeting 5	03 Oct 14
Workgroup Meeting 6	07 Oct 14
Workgroup Meeting 7	21 Oct 14
Workgroup Meeting 8	29 Oct 14
Panel grants two month extension	13 Nov 14
Workgroup Meeting 9 (joint with P316)	28 Nov 14
Workgroup Meeting 10 (joint with P316)	01 Dec 14
Assessment Procedure Consultation	16 Dec 14 – 14 Jan 15
Workgroup Meeting 11 (joint with P316)	21 Jan 15
Workgroup Meeting 12 (joint with P316) (if required)	23 Jan 15
Panel considers Workgroup's Assessment Report	12 Feb 15

Workgroup membership and attendance

P305 Workgroup Attendance											
Name	Organisation	1	2	3	4	5	6	7	8	9	10
Members											
Adam Lattimore	ELEXON *(Chair)*	✓	✗	✗	✗	✗	✗	✗	✗	✗	✗
Dean Riddell	ELEXON *(Chair)*	✗	✓	✓	✓	✓	✓	✓	✓	✓	✓
David Kemp	ELEXON *(Lead Analyst)*	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓
Sally Lewis	National Grid *(Proposer)*	✓	✓	✓	✓	✓	✓	✓	✓	✗	✗
Alex Haffner	National Grid *(Proposer's Alternate)*	✗	✗	✗	✗	✗	✗	✗	✗	✓	✓
Bill Reed	RWE	✓	✓	✗	✓	✓	✓	✓	✓	✓	✓
Esther Sutton	E.ON	✓	✓	✓	✓	✓	✗	✓	✓	✓	✓
Lisa Waters	Waters Wye Associates	✓	✓	✓	✓	✓	✓	✗	✗	✗	✗
Olaf Islei	APX	✓	✓	✗	✓	✗	✓	✗	✓	✓	✓
Sarah Owen	Centrica	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓
James Anderson	Scottish Power	✓	✗	✓	✓	✓	✓	✓	✓	✗	✗

P305 Workgroup Attendance											
Name	Organisation	1	2	3	4	5	6	7	8	9	10
Tom Edwards	Cornwall Energy	✓	✓	✗	✗	☎	☎	✗	✗	✓	✓
Andy Colley	SSE	✓	✓	✗	✓	✓	✓	☎	✓	✓	✓
Libby Glazebrook	GDF Suez	✓	✗	✗	✗	✓	✓	☎	✓	☎	✓
Colin Prestwich	SmartestEnergy	✓	✓	✗	✓	✗	✓	✓	✓	✓	✓
Cem Suleyman	Drax	✓	✓	✓	✓	✗	✗	✓	✓	✗	✗
Martin Mate	EDF	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓
Christine Hough	Haven	✓	✗	✗	✗	✗	✗	✗	✗	✗	✓
Alan Goodbrook	Good Energy	✗	✓	✓	✗	✗	✓	✓	✓	✓	✓
Keith Munday	First Utility	✗	✓	✓	✓	✗	✗	✗	✗	✓	✓
Stephen Mason	Hess	✗	✗	✗	✗	✓	✓	✓	✓	✗	✓
Attendees											
Talia Addy	ELEXON *(P316 Lead Analyst)*	✗	✗	✗	✗	✗	✗	✗	✗	✓	✓
Jonathan Priestley	ELEXON *(Design Authority)*	✓	✓	✓	✓	✗	✗	✗	✗	✗	✗
Nick Rubin	ELEXON *(Design Authority)*	✗	✗	✗	✓	✓	✓	✓	✓	✓	✓
Nick Brown	ELEXON *(Lead Lawyer)*	✓	✓	✗	✗	✗	✗	✗	✗	✗	✗
Stephen Casement	National Grid	✓	✓	✓	✓	✓	✗	✓	✓	✓	✗
Leon Walker	National Grid	✗	✓	✗	✗	✗	✗	✗	✗	✗	✗
Matthew Roberts	National Grid	✗	✗	✗	✓	✓	✗	✗	✓	✓	✗
Dominic Scott	Ofgem	✓	✗	✓	✓	✓	✓	✓	✗	✓	✓
Dipali Raniga	Ofgem	✓	✓	✓	✗	✓	✓	✓	✓	✓	✓
David Beaumont	Ofgem	✗	✓	✗	✓	✓	✓	✗	✓	✓	✓
Caroline Selman	Ofgem	✗	✓	✗	✗	✗	✗	✗	✗	✗	✗
James Soundraraju	Ofgem	✗	✗	✓	✓	✓	✗	✗	✗	✗	✗
Duncan Sinclair	Baringa	✗	✗	✗	✗	✗	✓	✗	✗	✗	✗
Richard Devenport	EDF	✓	✓	✓	✗	✓	✗	✓	☎	✓	✗
Mari Toda	EDF	✓	☎	✓	✗	✗	✗	✓	✗	✗	✗
Sam Hollister	Energy UK	✓	✗	✓	✗	✗	✗	✗	✗	✓	✗
Pavel Miller	Energy UK	✗	✓	✗	✗	✗	✗	✗	✗	✗	✗
Christopher Steele	Energy UK	✗	✗	✗	✓	✗	✓	✓	✗	✗	✗
John Lawton	ENWL	☎	✗	✗	✗	✗	✗	✗	✗	✗	✗
Jeremy Guard	First Utility	✗	✓	✗	✗	✗	✗	✓	✗	✗	✓
Nick Haines	Good Energy	✗	✗	✗	✓	✗	✗	✗	✗	✗	✗
Phil Hewitt	EnAppSys	✗	✗	✗	✗	✗	✓	✗	✗	✗	✗
Peter Bolitho	Waters Wye Associates	✗	✗	✗	✗	✗	✗	✓	✗	✓	✓

Appendix 3: EBSCR Document References

EBSCR Final Policy Decision documents

EBSCR – Final Policy Decision Impact Assessment, May 2014

EBSCR – Business Rules, May 2014

EBSCR – Further analysis to support Ofgem's Updated Impact Assessment, Baringa, May 2014

These three documents can be accessed at:

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

Directions issued by GEMA to National Grid in relation to EBSCR, May 2014

https://www.ofgem.gov.uk/publications-and-updates/direction-national-grid-electricity-transmission-plc-relation-electricity-balancing-significant-code-review

EBSCR forward modelling results (2014)

https://www.ofgem.gov.uk/ofgem-publications/88744/ebscrforwardmodellingresults.xlsx

EBSCR Draft Policy Decision documents

Electricity Balancing Significant Code Review – Draft Policy Decision, July 2013

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

Electricity Balancing Significant Code Review – Draft Policy Decision Impact Assessment, July 2013

https://www.ofgem.gov.uk/ofgem-publications/82295/ebscr-draft-policy-decision-impact-assessment.pdf

Electricity Balancing SCR: Quantitative Analysis, Baringa, July 2013

http://www.ofgem.gov.uk/Markets/WhlMkts/CompandEff/electricity-balancing-scr/Documents1/Baringa%20EBSCR%20quantitative%20analysis.pdf

The Value of Lost Load for Electricity in Great Britain, London Economics, July 2013

http://www.ofgem.gov.uk/Markets/WhlMkts/CompandEff/electricity-balancing-scr/Documents1/London%20Economics%20Value%20of%20Lost%20Load%20for%20electricity%20in%20GB.pdf

Further EBSCR documents

Electricity Balancing Significant Code Review – Initial Consultation, August 2012 (Reference 108/12)

www.ofgem.gov.uk/Markets/WhlMkts/CompandEff/electricity-balancing-scr/Documents1/Electricity%20Balancing%20SCR%20initial%20consultation.pdf

Electricity cash-out issues paper, November 2011, (Reference 143/11)

www.ofgem.gov.uk/Markets/WhlMkts/CompandEff/CashoutRev/Documents1/Electricity%20cash-out%20issues%20paper.pdf

Cash-out price data (2013)

https://www.ofgem.gov.uk/ofgem-publications/82972/cash-outpricedata.xlsx

P217A preliminary analysis (2012)

https://www.ofgem.gov.uk/ofgem-publications/40803/p217a-preliminary-analysis.pdf

P217A preliminary analysis data (2012)

https://www.ofgem.gov.uk/ofgem-publications/40784/p217a-preliminary-analysis-data.xlsx

Acronyms

Acronyms used in this document are listed in the table below.

Glossary of Defined Terms	
Acronym	Definition
BM	Balancing Mechanism
BMRA	Balancing Mechanism Reporting Agent *(BSC Agent)*
BMRS	Balancing Mechanism Reporting Service
BOA	Bid-Offer Acceptance
BPA	Buy Price Adjustment *(value)*
BSAD	Balancing Services Adjustment Data *(value)*
BSCP	BSC Procedure *(document)*
CADL	Continual Acceptance Duration Limit *(parameter)*
CDCA	Central Data Collection Agent *(BSC Agent)*
CfD	Contracts for Difference
CM	Capacity Mechanism
CPI	Consumer Price Index
CSD	Code Subsidiary Document *(document)*
DECC	Department of Energy and Climate Change *(Government department)*
DSBR	Demand Side Balancing Reserve
DSO	Distribution System Operator *(BSC Party)*
DSR	Demand Side Response
DTC	Data Transfer Catalogue
EBSCR	Electricity Balancing Significant Code Review
EMR	Electricity Market Reform
GB	Great Britain
GSP	Grid Supply Point
HH	Half Hourly
II	Interim Information *(Settlement Run)*
ISG	Imbalance Settlement Group *(Panel Committee)*
LCPD	Large Combustion Plant Directive *(European Regulation)*
LFDD	Low Frequency Demand Disconnection
LoLP	Loss of Load Probability *(value)*
MEL	Maximum Export Limit
MIDS	Market Index Definition Statement *(document)*
MPAN	Meter Point Administration Number

Glossary of Defined Terms	
Acronym	Definition
NDZ	Notice to Deviate from Zero
NETSO	National Electricity Transmission System Operator
NHH	Non Half Hourly
NIV	Net Imbalance Volume *(value)*
PAR	Price Average Reference *(parameter)*
PN	Physical Notification
REMIT	Regulation on wholesale energy markets integrity and transparency *(European Regulation)*
RPAR	Replacement Price Average Reference *(parameter)*
RSP	Reserve Scarcity Price *(value)*
SAA	Settlement Administration Agent *(BSC Agent)*
SBP	System Buy Price *(value)*
SBR	Supplementary Balancing Reserve
SCR	Significant Code Review
SF	Initial Settlement *(Settlement Run)*
SO	System Operator
SQSS	Security and Quantity of Supply Standard
SSP	System Sell Price *(value)*
STAG	Software Technical Advisory Group *(Panel Sub-group)*
STOR	Short Term Operating Reserve
SVAA	Supplier Volume Allocation Agent *(BSC Agent)*
TWG	Technical Working Group *(SCR Workgroup)*
VoLL	Value of Lost Load *(parameter)*

External links

A summary of all hyperlinks used in this document are listed in the table below.

Hyperlinks listed in Appendix 3 are not included here.

All external documents and URL links listed are correct as of the date of this document.

External Links		
Page(s)	Description	URL
3, 6, 22	EBSCR page on the Ofgem website	https://www.ofgem.gov.uk/electricity/wholesale-market/market-efficiency-review-and-reform/electricity-balancing-significant-code-review
4	Imbalance and Pricing page on the ELEXON website	http://www.elexon.co.uk/reference/credit-pricing/imbalance-pricing/

External Links		
Page(s)	Description	URL
5	Grid Code page on the National Grid website	http://www2.nationalgrid.com/UK/Industry-information/Electricity-codes/Grid-code/The-Grid-code/
6	Project Discovery Final Report on the Ofgem website	https://www.ofgem.gov.uk/ofgem-publications/40354/projectdiscoveryfebcondocfinal.pdf
6, 13, 40, 51, 52, 55	EBSCR Final Policy Decision page on the Ofgem website	https://www.ofgem.gov.uk/publications-and-updates/electricity-balancing-significant-code-review-final-policy-decision
7	EBSCR Direction page on the Ofgem website	https://www.ofgem.gov.uk/publications-and-updates/direction-national-grid-electricity-transmission-plc-relation-electricity-balancing-significant-code-review
7, 12	P304 page on the ELEXON website	http://www.elexon.co.uk/mod-proposal/p304/
7, 13, 21, 48, 55	P305 page on the ELEXON website	http://www.elexon.co.uk/mod-proposal/p305/
12	P314 page on the ELEXON website	http://www.elexon.co.uk/mod-proposal/p314/
12	P316 page on the ELEXON website	http://www.elexon.co.uk/mod-proposal/p316/
23	P205 page on the ELEXON website	http://www.elexon.co.uk/mod-proposal/p205-increase-in-par-level-from-100mwh-to-500mwh/
23	P194 page on the ELEXON website	http://www.elexon.co.uk/mod-proposal/p194-revised-derivation-of-the-main-energy-imbalance-price/
23	P217 page on the ELEXON website	http://www.elexon.co.uk/mod-proposal/p217-revised-tagging-process-and-calculation-of-cash-out-prices/
30, 32, 55	ELEXON Portal *(a free login account is required to access this data)*	https://www.elexonportal.co.uk/
33	Transparency Regulation on the EUR-Lex website	http://eur-lex.europa.eu/LexUriServ/LexUriServ.do?uri=OJ:L:2013:163:0001:0012:EN:PDF
36	REMIT Regulation on the EUR-Lex website	http://eur-lex.europa.eu/LexUriServ/LexUriServ.do?uri=OJ:L:2011:326:0001:0016:EN:PDF
40, 50	EBSCR Draft Policy Decision page on the Ofgem website	https://www.ofgem.gov.uk/publications-and-updates/electricity-balancing-significant-code-review-draft-policy-decision

External Links		
Page(s)	Description	URL
40, 45	DECC-Ofgem VoLL Study by London Economics Report on the Ofgem website	https://www.ofgem.gov.uk/ofgem-publications/82293/london-economics-value-lost-load-electricity-gb.pdf
47	GC0050 page on the National Grid website	http://www2.nationalgrid.com/UK/Industry-information/Electricity-codes/Grid-code/Modifications/GC0050/
47	P199 page on the ELEXON website	http://www.elexon.co.uk/mod-proposal/p199-quantification-of-demand-control-in-the-bsc-as-instructed-under-oc-6-cd-e-of-the-grid-code/
48	STAG page on the ELEXON website	http://www.elexon.co.uk/group/software-technical-advisory-group-stag/
48	P299 page on the ELEXON website	http://www.elexon.co.uk/mod-proposal/p299/
51	P306 page on the ELEXON website	http://www.elexon.co.uk/mod-proposal/p306/
51	P307 page on the ELEXON website	http://www.elexon.co.uk/mod-proposal/p307/
51	P308 page on the ELEXON website	http://www.elexon.co.uk/mod-proposal/p308/