Detailed Assessment

P305 'Electricity Balancing Significant Code Review Developments'

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

This document covers the detailed analysis produced by the P305 Workgroup as part of its considerations of P305.

1 Proposed LoLP Function Straw Man Specification

This Section details the approach National Grid, as the Transmission Company, has taken to calculating a Loss of Load Probability (LoLP) value for P305. This is a high-level summary of the model that has been proposed to the P305 Workgroup, and is not intended to be definitive.

Definition of Indicative and Final LoLP

The LoLP function is a measure of reliability that will be calculated for each Settlement Period. For a given level of MW demand on the system the associated LoLP indicates the probability that there will be insufficient generating supply (Z) to meet the capacity requirement (CR).

Purpose of Indicative and Final LoLP

A LoLP calculated using forecast data at Gate Closure for a Settlement Period will be used within a Reserve Scarcity Price (RSP) calculation which will be the product of the LoLP value and the Value of Lost Load (VoLL), as specified within the Electricity Balancing Significant Code Review (SCR) (EBSCR) Final Policy Decision. When the RSP is greater than the Utilisation Price for a Short Term Operating Reserve (STOR) action taken within a Settlement Period it will replace it, but only if that Settlement Period falls within a STOR Availability Window. The LoLP will be calculated at Gate Closure.

Indicative LoLP values will be calculated at lead time provisionally set to day-ahead, eight, four and two hours ahead of real time. These indicative values will act as a signal to market to capture the extent to which the current system conditions can sufficiently provide for a forecasted capacity requirement.

All calculations for a particular Settlement Period are based on forecast data and therefore will not reflect outturn data in the event of a loss of load to the system following Gate Closure.

Calculating LoLP

If Z is a random variable representing the available generation and CR is a random variable representing capacity required, then LoLP can be defined as:

$$LoLP = P(Z - CR < 0)$$

The following method statement focuses on the approach to modelling the LoLP calculation that will feed into the imbalance price. The implementation of indicative LoLP models will adjust for the varying lead time of available input data.

Modelling generation supply (Z)

Modelling conventional generation (X)

The random variable X is the sum of n binomial random variables, each of which represents the available capacity from a conventionally fuelled Balancing Mechanism (BM) Units (including BM STOR units):

$X = X_1 + X_2 + \ldots X_n$

$X_i \sim CAP_i * B(1, AV_i)$

Where:

$CAP_i =$	$\{ MEL_i$	$FPN_i \neq 0$
	$\{ MEL_i$	$NDZ_i <$ Lead Time + 30 minutes **AND** unit desynchronised before MZT_i
	$\{ 0$	otherwise

FPN_i = Final Physical Notification for unit i

NDZ_i = Notice to Deviate from Zero for unit i

MEL_i = Maximum Export Limit for unit i as submitted at Gate Closure

AV_i = Availability factor for unit i (calculated fuel type uncertainty factor applied to that unit based on historic MEL submissions)

MZT_i = Minimum Zero Time for unit i

LT = Lead Time (minutes)

Modelling availabilities (AV_i)

To account for the uncertainty that a unit may not be available between a Maximum Export Limit (MEL) submission (pre-gate and at Gate Closure) and real time, uncertainty factors are calculated. In the model output produced to date, these availabilities are calculated using the past one year of MEL submission data.

We would propose that for implementation the model uses an average MEL uncertainty factor for each fuel type that should be calculated for each day over a one year rolling historic period and averaged. This daily availability average is calculated by:

$$AV_{ft} = \Sigma\,(\min\,(MEL_{RTft}, MEL_{1ft})) \,/\, \Sigma\, MEL_{1ft}$$

Where:

ft = {Coal, Gas, Hydro, Pump Storage, Nuclear, OCGT, Oil), fuel types

MEL_{1ft} = The average MEL of the most recent time series submitted one hour before the given Settlement Period for a unit of given fuel type

$MEL_{RTf}t$ = The real time average MEL for the given Settlement Period for a unit of a given fuel type

In these calculations real time MEL is capped to the forecasted MEL submission. Otherwise availability factors greater than 1 will result in some instances. This is especially the case for a nuclear plant that has an agreed practice to use MEL as a means of ramping to load on synchronising.

$X_i \sim CAP_i * B(1, AV_i)$

$X_i \sim CAP_i * B(1, AV_i)$ represents the available capacity of conventionally fuelled BMU i where:

CAP is capacity of unit i; and

$B(1, AV_i)$ represents the binomial distribution that unit i will be available at real time.

Lead Time + 30 minutes treatment of NDZ

When deriving the available capacity of a unit, the MEL is counted for all units that can be synchronised at any point within the relevant Settlement Period (hence the NDZ accounts for the lead time to the start of the Settlement Period plus 30 minutes to the end).

Modelling wind (W)

Further to the binomial generation capacities of conventional units (X) that make up generation supply (Z), there must be an additional component that accounts for wind generation (W) and its associated forecast error.

It is suggested that the wind variable is calculated using National Grid wind forecasted values. The wind forecast system currently performs model runs every six hours, which is dependent on the receipt of weather data, producing hourly forecasts. Forecast values up to six hours ahead of real time are blended with metered values for increased accuracy.

The error distribution of wind forecasts is closer to a Laplace distribution than a Normal distribution. Therefore the wind component can be modelled as a Laplace distribution with the mean as W_{fcst} and scale factor consisting of the mean absolute error of W_{fcst}:

$$Wind \sim L(median = W_{fcst}, \text{scale factor} = W_{fcst\ error\ term})$$

Where:

W_{fcst} = Most recent wind forecast to Gate Closure for Settlement Period x

$W_{fcst\ error\ term} = W_{fcst\_mape} * W_{capacity}$

W_{fcst_mape} = Wind forecast mean absolute error as a percentage of installed wind capacity

$W_{capacity}$ = Installed wind capacity as of Settlement Period

To allow for seasonal variation a W_{fcst_mape} will be calculated from the previous winter (November to March) and summer (April to October) dates.

Modelling generation supply (Z)

The binomial distributions of X and Laplace distribution W can then be combined statistically, such that:

$$Z = X + W$$

Modelling capacity requirement (CR)

All other forms of generation and demand can be placed into a single random variable representing the conventional generation requirement. By doing this we allow the random variable X to simply be the sum of binomial values. The capacity requirement (CR) can be defined as:

$$CR = SD + LLR - STOR$$

Where:

SD = (GB Demand + Interconnector Flow + Station Load + System Losses)

Interconnector Flow = $\Sigma_{k \in ICs}$ (IC_FLOW_k) (where exports are positive)

IC_s = {IFA, BRITNED, MOYLE, EAST_WEST}

IC_FLOW = Interconnector market flow

Non-BM STOR

Since non-BM STOR units are not used as frequently as other forms of generation of the same fuel type, non-BM STOR is extracted from the 'conventional generation' part of the equation. In the 'CR' part of the equation non-BM STOR is therefore considered negative capacity requirement.

LLR = Largest Loss Reserve. This is the equation to determine the reserve held for the potential largest loss on the system. The quantity of reserve required to withstand a largest loss to regain the system to 50Hz (typically 1,260MW for Sizewell B. Please see Annex 2 later on in this Section for more details

STOR = Non-BM STOR (BM STOR is included in conventional generation X)

In principle all components of CR should be random variables. In the analysis so far we have assumed that STOR, LLR and IC have no uncertainty. As Interconnector imports are a form of generation but are not treated as conventional generation, they are accounted for within the demand definition instead of as part of the Interconnector flow.

Modelling capacity requirement

CR (as defined within this document) is primarily a collective of GB demand, Interconnector flow and non-BM STOR. The indicative GB demand is a function of a National Grid forecasted variable. The indicative Interconnector position will be the initial market flow Physical Notification (PN) position. The indicative position of non-BM STOR will be the most recent submitted availability. The combined variables are treated as having a normally distributed error component, such that:

$$CR \sim CR_{fcst} + N(\mu, \sigma^2)$$

$$CR \sim CR_{fcst} + N(0, CR_{err}^2)$$

Where:

CR_{fcst} = Average forecast for the Settlement Period using the most recent values for GB demand, Interconnector flow from PN and submitted non-BM STOR availability

CR_{err} = Root Mean Squared Error of CR_{fcst} to reported Outturn. Two uncertainty values should be created to account for seasonal variation: Winter (November to March) and Summer (April to October). Both figures will be calculated on an annual basis

Modelling non-BM STOR and Interconnectors

STOR unit uncertainty is captured in the conventional generation (X) modelling. For simplicity in including the uncertainty of both Interconnector flow and non-BM STOR into the model, these values should be included whilst calculating the root mean squared error of CR.

Annex 1: Generation Supply (Z)

Conventional generation (X)

Gas plant: two state option

It has been considered that gas plant typically contain multiple generation modules per BM Unit. A gas BM Unit is therefore not necessarily limited to being fully working or failed. To account for this across the fuel type as a whole, the number of gas units is doubled and capacities halved for the purposes of the binomial distribution in historic analysis.

Modelling availabilities (AV_i)

Currently an average MEL uncertainty factor for each fuel type has been calculated for each day for the past year and then averaged across the whole period. This daily availability average is calculated by:

$$AV_{ft} = \Sigma\ (\min\ (MEL_{RTft}, MEL_{xft}))\ /\ \Sigma\ MEL_{xft}$$

Where:

x = 1 hour ahead of real time forecasted MEL submission

In response to concerns of the P305 Workgroup regarding the best reflection of generator availability at lead times greater than one hour, the availability factor used at all lead times is proposed to be the historically calculated one hour AV_{ft}.

Availabilities Factors from Forecast MEL	
Fuel type	Availability factor
Coal	0.986
Gas	0.989
Hydro	0.988
Nuclear	0.998
OCGT	0.997
Oil	0.998
Pumped Storage	0.998

Annex 2: Capacity requirement (CR)

Largest Loss Reserve

The subsection below summarises a note issued by Ofgem discussing the reserve for response from first principles. For the implementation within the LoLP calculation and ease of replication from market participants the equation assumes no Firm Frequency Response (FFR) machines and no static provision.

Largest Loss Reserve = ((Loss – Demand * 1%) / Response Remaining Factor) / URRM

Where:

Response Remaining Factor = 0.68

URRM = 0.55 (The Upward Response Reserve Multiplier models how much frequency response can be delivered from the available headroom)

Loss = 1,260MW (As defined in the Security and Quality of Supply Standards (SQSS))

Demand = Most recently calculated National Demand Forecast + Station Load (MW)

Reserve for response from first principles

Given the characteristics of demand, the demand level and the size of a loss, we calculate the amount of response we need to be delivered as follows:

Secondary response delivery required (assuming 49.9Hz-49.5Hz deviation and assuming a demand sensitivity of 2.5%/Hz, (i.e. if the frequency reduces by 1Hz then demand reduces by 2.5%))

= Loss – Demand * %/Hz * Hz deviation

= Loss – Demand * 2.5%/Hz * 0.4Hz

= Loss – Demand * 1%

That response required is made up of two parts: static and dynamic provision. Dynamic response is continually acting to dampen frequency deviations. As the largest infeed loss could occur at any time, it is assumed that the frequency is at 49.9Hz when the largest infeed loss occurs, meaning that a proportion of the dynamic response has already been provided. To allow for this pre-fault commitment of response, we calculate the dynamic response requirement:

Dynamic secondary response instructed required

= (Secondary response delivery required – static service provision) / (100% – percentage of response delivered pre-fault)

= (Secondary response delivery required – static service provision) / Response Remaining Factor

The Upward Response Reserve Multiplier (URRM) models how much frequency response can be delivered from the available headroom. Historically the URRM has been modelled as 0.55 across the day. Recent analysis (following publication of the 2013/14 Winter Outlook) shows that at peak demand when plant is operating close to maximum and the secondary response requirement is the driving requirement, then the URRM improves to 0.67.

Pump storage units providing response under FFR contracts have specific response efficiency and so the URRM is not applied to this part of the response provision. We separate out this response provision:

Reserve required

= (Dynamic secondary response instructed required – FFR Provision) / URRM + Reserve for FFR Provision

Combining the formulae above gives:

Reserve for Response

= ((Loss – Demand * 1% – Static Response Provision) / Response Remaining Factor – FFR Provision) / URRM + Reserve for FFR Provision

Example calculations

Assuming that we have a largest loss of 1,260MW, a demand of 56,300MW, no FFR machines and no static provision, we get a reserve for response figure of:

Reserve for Response

= ((Loss – Demand * 1% – Static Response Provision) / Response Remaining Factor – FFR Provision) / URRM + Reserve for FFR Provision

= ((1,260 – 56,300 * 1% – 0) / 0.68 – 0) / 0.55 + 0

= 1,863MW

Annex 3: Historical analysis

The mathematical specification above has been applied to historic data from 1 January 2013 to 24 October 2014. The capacity requirement and wind error statistics used for both yearly runs utilise the forecast and outturn figures for 2013 as a fair reflection of current system state.

De-rated margin

The de-rated margin figure utilised for plotting historical analysis charts is derived from the input variables of the model. Where applicable, the data will be the latest iteration at the specified indicative time (one, two, four, eight, 12 and 24 hours ahead) in question:

De-rated Margin

= (Sum of de-rated MELs + Wind Forecast) – Capacity Requirement

= $(\text{Sum}_{\text{overBMUs}}\ (\text{MEL}_{\text{LeadTime}} * \text{AV}_{\text{ft}}) + \text{Wind Forecast}_{\text{LeadTime}}) - \text{Capacity Requirement}_{\text{LeadTime}}$

Where:

Wind Forecast and Capacity Requirement are as defined previously

2 Proposed LoLP Function Analysis

This Section summarises the results of National Grid's LoLP modelling as proposed in the straw man in Section 1. Due to the iterative process of the method's development in response to Workgroup suggestions, the analysis focuses on the most recent iteration of the model and does not consider previous iterations.

Overview of the analysis

National Grid performed multiple model runs utilising a core baseline model updated from Workgroup suggestions.

1. **Baseline model**

   The baseline contained recommended adjustments following previous Workgroup meetings, in particular:

   - When considering the Notice to Deviate from Zero (NDZ) time to derive the available capacity (MEL), the lead time has been extended by 30 minutes to capture the duration of the Settlement Period (as opposed to the previous baseline model which assessed whether the unit could be synchronised by the start of the Settlement Period)

   - All availability factors by fuel type (for all lead times) are now based on the historically calculated availability factors for one hour ahead (i.e. the Gate Closure availability figures)

   - Availability factors for conventional generation are derived on one year (rather than three years) of data

2. **Baseline + 'Eight Hour Look Back' model**

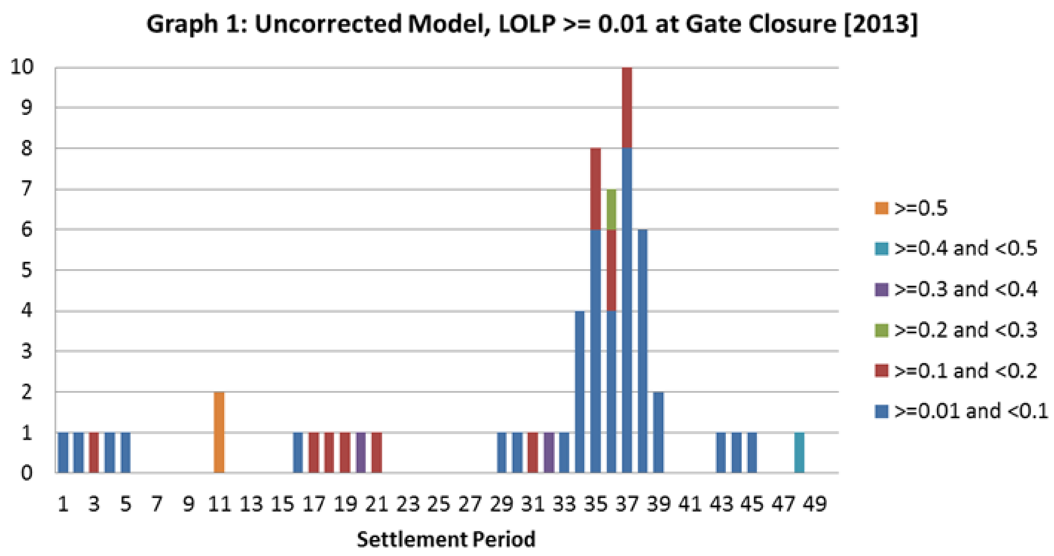
   This is the Baseline model as described above except that when calculating the available capacity the MELs are counted for any unit that, at the time of calculation, had been operating with a PN greater than zero within the last eight hours. The intention of this version is to capture the ability of the National Grid control room to keep units running from Bid-Offer Acceptances if required.

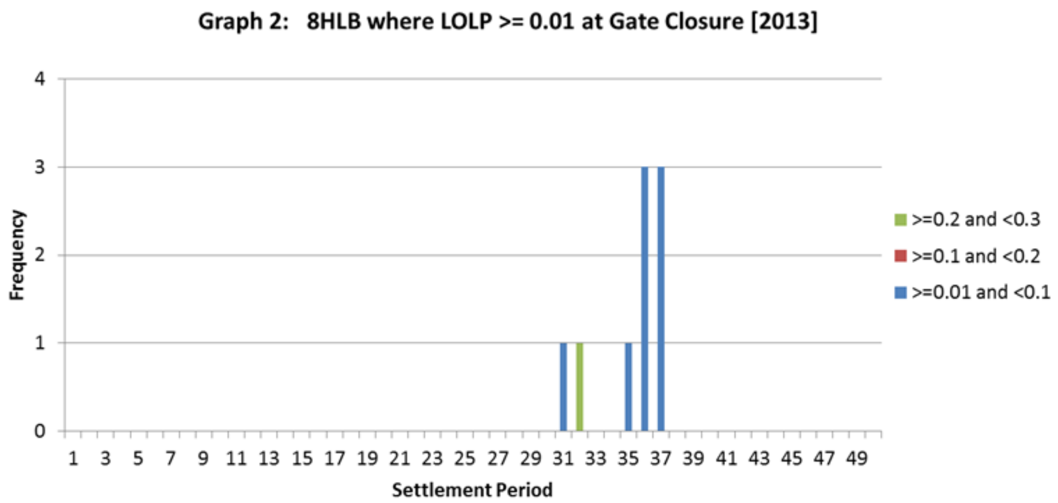
This analysis focuses on the **Baseline + 'Eight Hour Look Back' model**, as this was the model the P305 Workgroup agreed should be progressed. This model addressed the concerns of high LoLPs in overnight Settlement Periods that had been observed in previous iterations.

This analysis covers the period 1 January 2013 to 24 October 2014 for lead times of 24, 12, eight, four, two and one hour(s) ahead of the relevant Settlement Period.

Summary of 2013 analysis

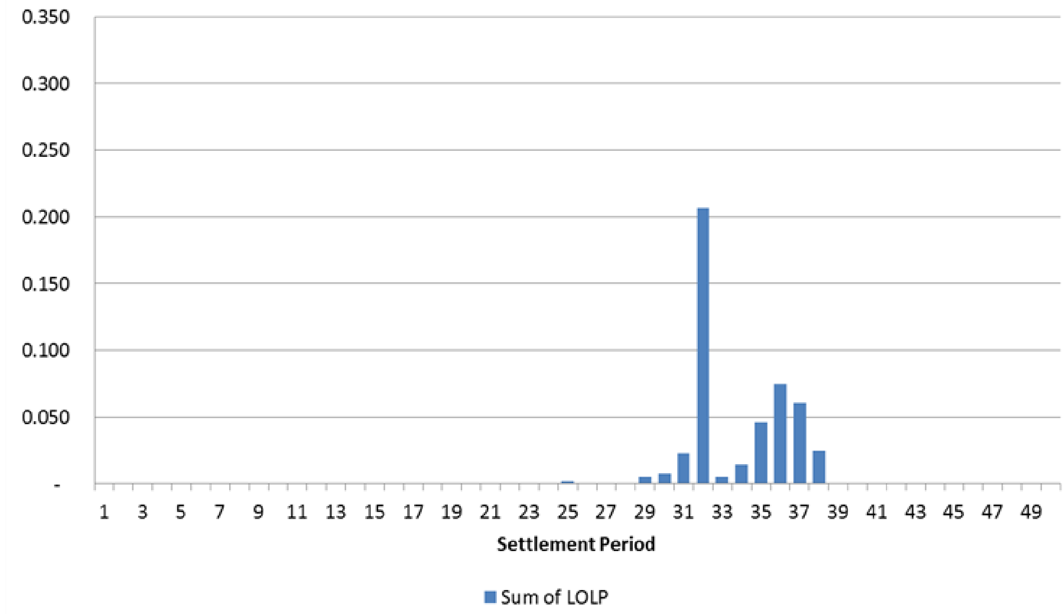
Graph 1 represents the frequency of times where the LoLP at Gate Closure was greater than 0.01 (1%) within the uncorrected model, which demonstrates the occurrence of high overnight LoLP values. These high values were corrected within the Baseline + 'Eight Hour Look Back' model. Graph 2 represents this correction for the same 2013 time period showing a significantly lower number of LoLP values greater than 0.01 compared to Graph 1 due to the extension in NDZ.





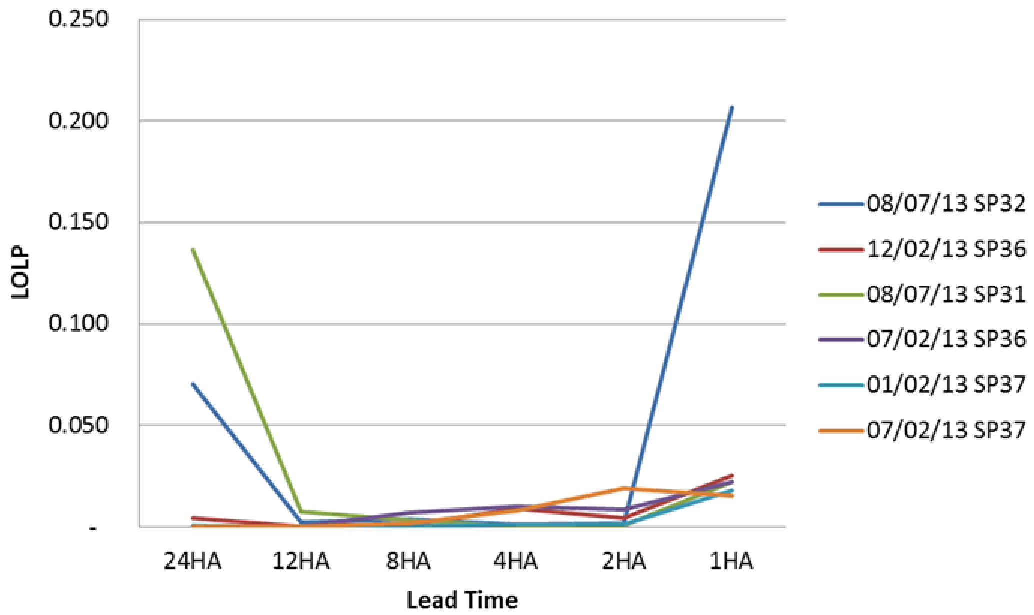
The summation of LoLP values per Settlement Period for the whole year is a useful metric in determining the overall behaviour of the model in reference to the time of day and whether high LoLPs typically occur over the demand peak as might be intuitively expected. However a singular event in which a unit(s) falls off the system at a time of tighter than usual margin will appear as an outlier. Such an event happened in Settlement Period 32 on 8 July 2013 which is visible in Graph 3.

Graph 3: 8HLB Sum of LOLP at Gate Closure [2013]

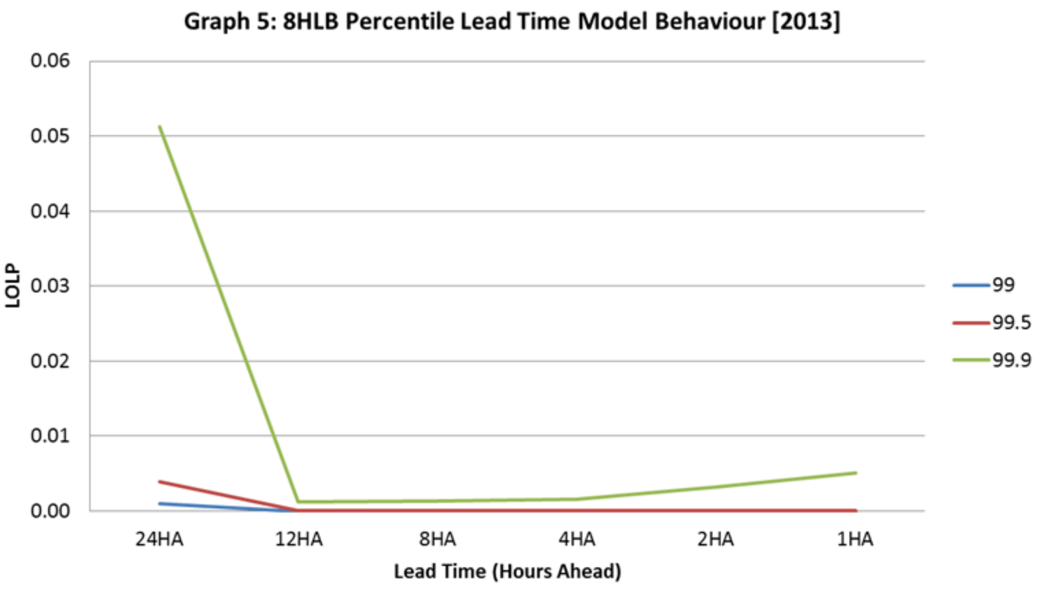


The highest five Final LoLP values in 2013 are depicted in Graph 4. This illustrates how a unit(s) falling off the system is unpredictable and at times of tight margin will cause a sharp rise between two and one hour(s) ahead in recognition of the limited time the system can respond.

Graph 4: 8HLB Top 5 LOLPs [2013]



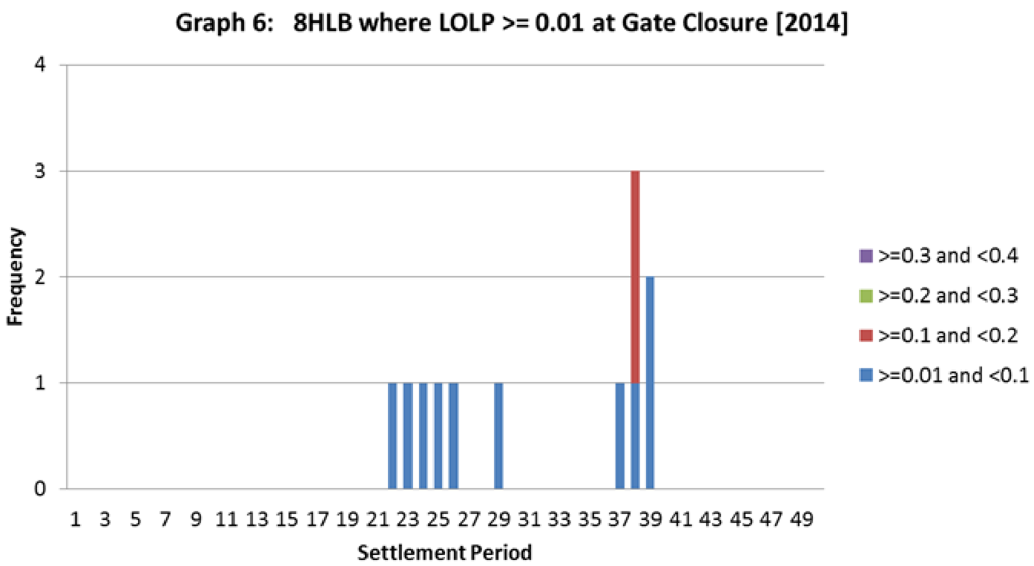
To represent typical model behaviour throughout the various lead times, percentiles are shown in Graph 5. These show that for 99.5% of Final LoLP values in 2013 the values are below 0.01 (1%) for all lead times from 24 hours ahead and transition smoothly between those lead times. The higher LoLP values at 24 hours ahead will be predominately influenced by the accuracy of thermal unit MEL submissions (rather than wind or demand forecast error).

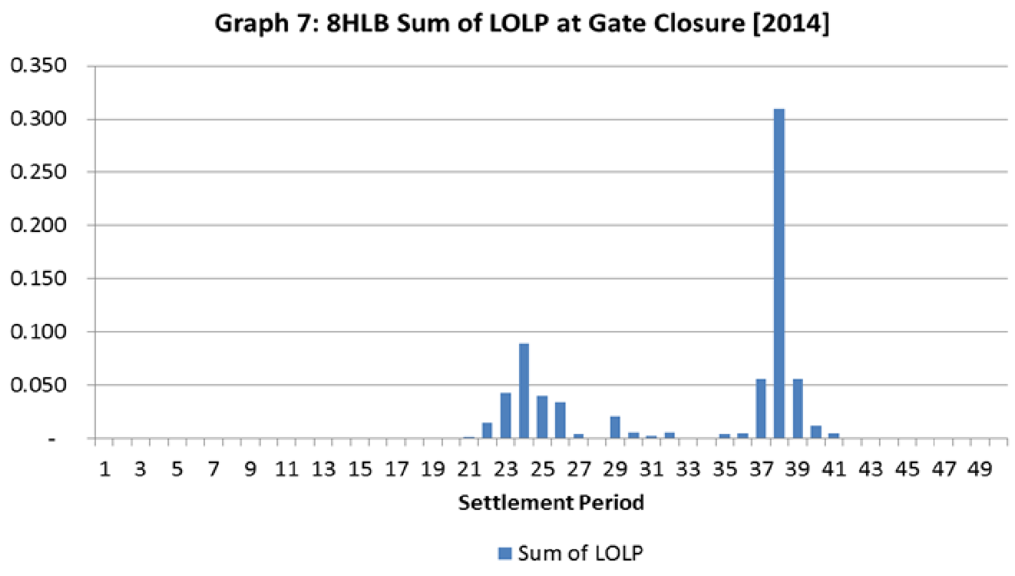


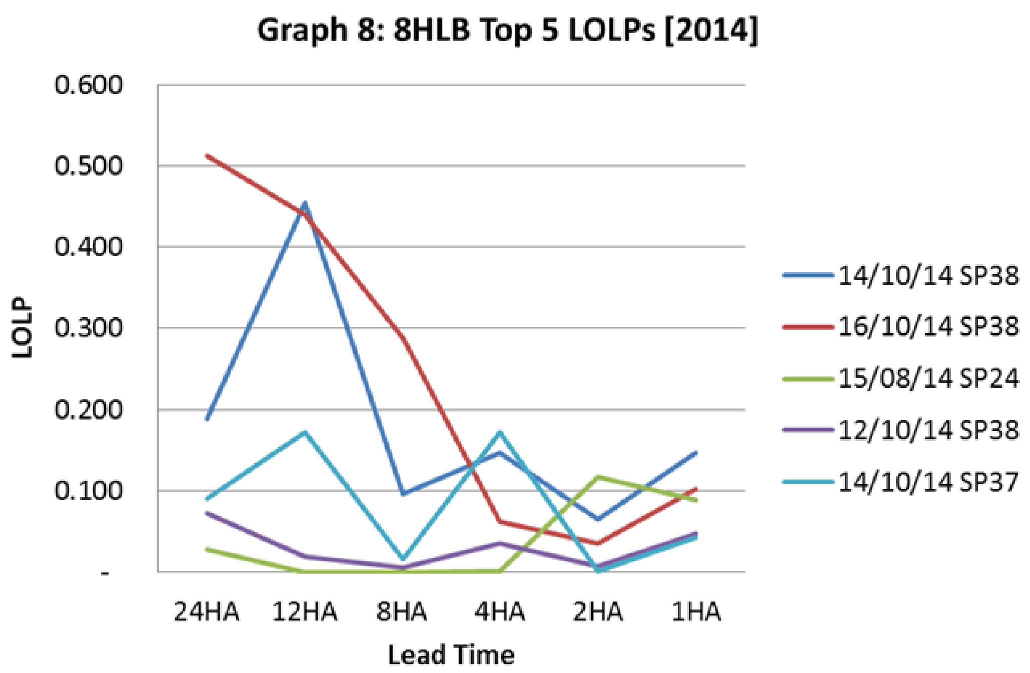
It should be noted that in the main, 2013 was a rather benign year and therefore one would not expect to see very many LoLP values above 0.1 (10%) and indeed any at a high level, reflected by the absence of any Notices of Insufficient System Margin (NISMs) over that period.

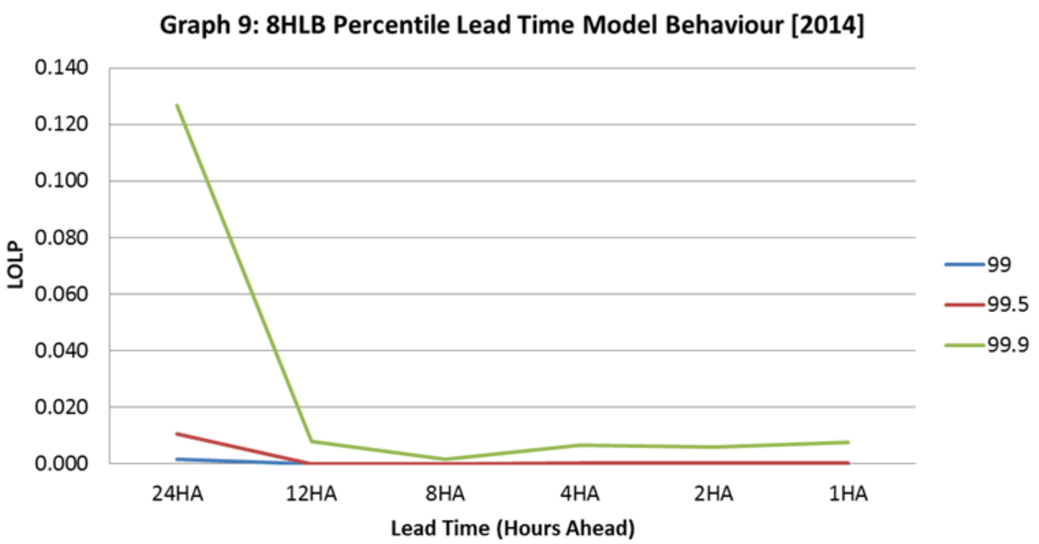
Summary of 2014 analysis

The behaviour of the model across 2014 is demonstrated in Graphs 6-9, which are the equivalent to Graphs 2-5 used to illustrate the 2013 data. The model picked up the tightest Settlement Period to date (14 October 2014 Settlement Period 38) as one would expect. The shifting profile of demand between summer and winter was more readily noticeable in Graph 7, with a cluster of higher Final LoLP values surrounding Settlement Periods 23 to 25.




Graph 7: 8HLB Sum of LOLP at Gate Closure [2014]
0.350
0.300
0.250
0.200
0.150
0.100
0.050
-
1 3 5 7 9 11 13 15 17 19 21 23 25 27 29 31 33 35 37 39 41 43 45 47 49
Settlement Period
Sum of LOLP

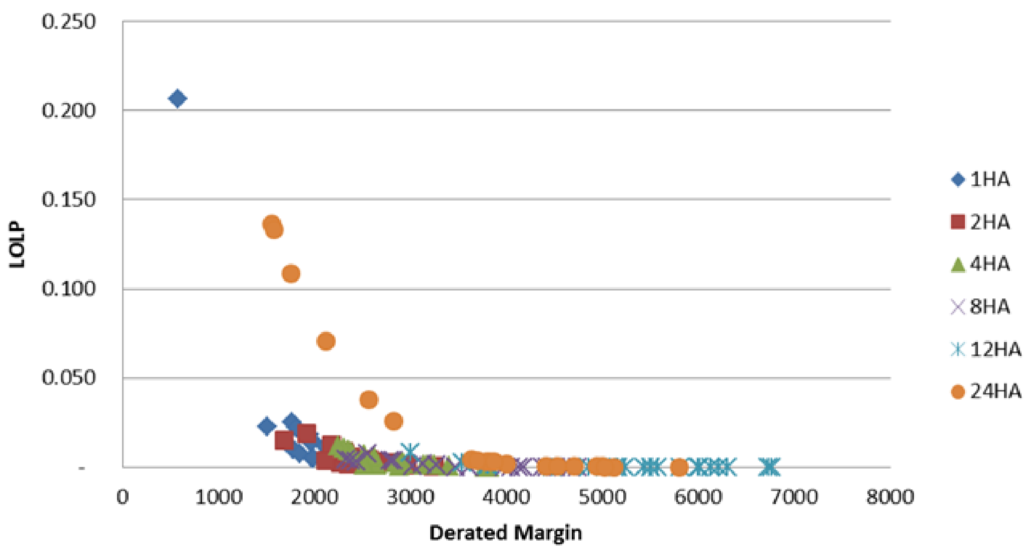

Graph 8: 8HLB Top 5 LOLPs [2014]
0.600
0.500
0.400
0.300
0.200
0.100
-
LOLP
24HA 12HA 8HA 4HA 2HA 1HA
Lead Time
14/10/14 SP38
16/10/14 SP38
15/08/14 SP24
12/10/14 SP38
14/10/14 SP37


Graph 9: 8HLB Percentile Lead Time Model Behaviour [2014]
0.140
0.120
0.100
0.080
0.060
0.040
0.020
0.000
LOLP
24HA 12HA 8HA 4HA 2HA 1HA
Lead Time (Hours Ahead)
99
99.5
99.9

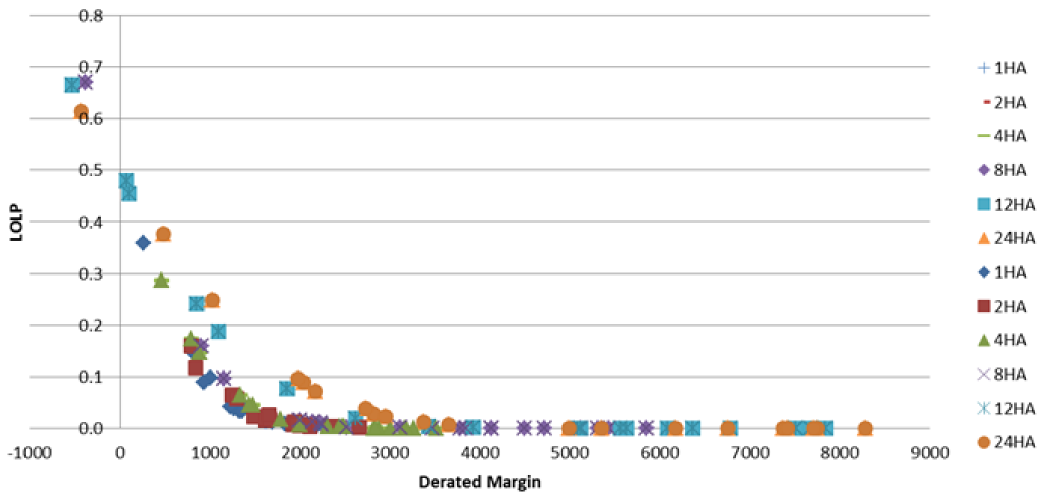
LoLP versus de-rated margin

The captured de-rated margin (as specified in Annex 3 of Section 1) utilises the inputs of the LoLP model. The varying curves of the model represent the varying uncertainty at each lead time.

Graph 10: 8HLB LOLP vs Derated Margin [2013]



Graph 11: 8HLB LOLP vs Derated Margin [2014]

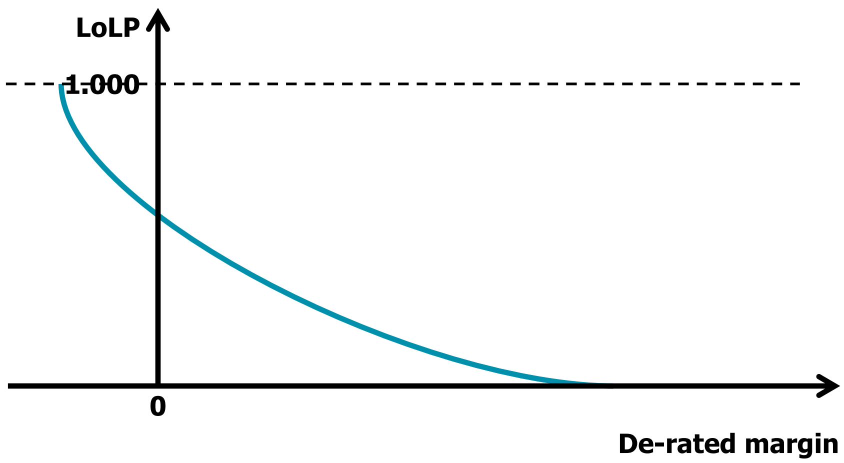


3 Alternative LoLP Function Straw Man Specification

This Section summarises the alternative 'static' LoLP function that has been developed by the Workgroup following consideration of the proposed 'dynamic' function detailed in Section 1. Some details around this approach are still to be finalised, and no analysis has been undertaken to date to demonstrate the effect of creating and using such a function.

Requirements of the function

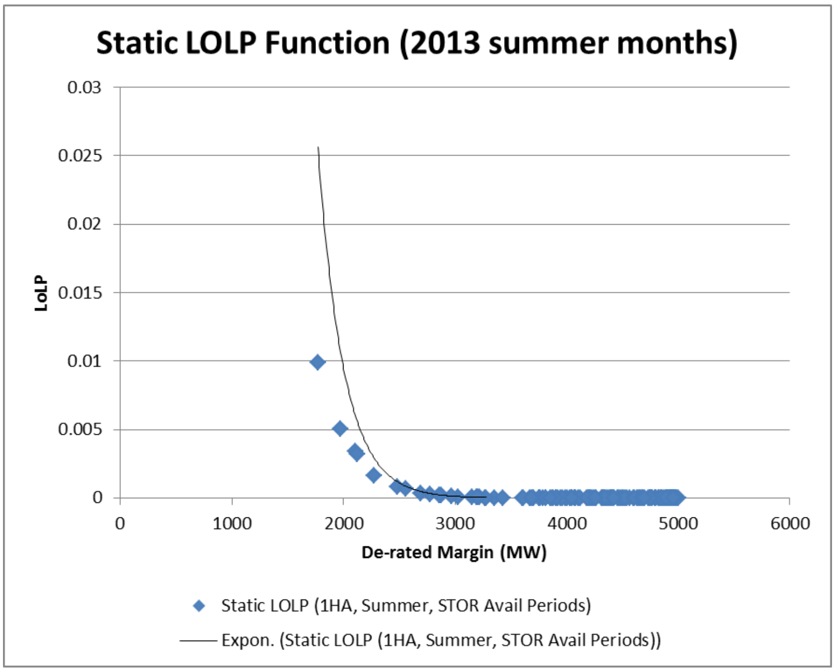
The Workgroup's alternative 'static' LoLP function proposes to generate a mathematical relationship between historical values of de-rated margin and LoLP. This mathematical relationship enables a static function to be derived such that a forecasted de-rated margin in a given Settlement Period would identify a LoLP value that would be used to calculate the Settlement Period's RSP. This approach is based on the principle that the chance of load being lost increases as the margin tightens. The diagram below illustrates the expected relationship between LoLP and de-rated margin.

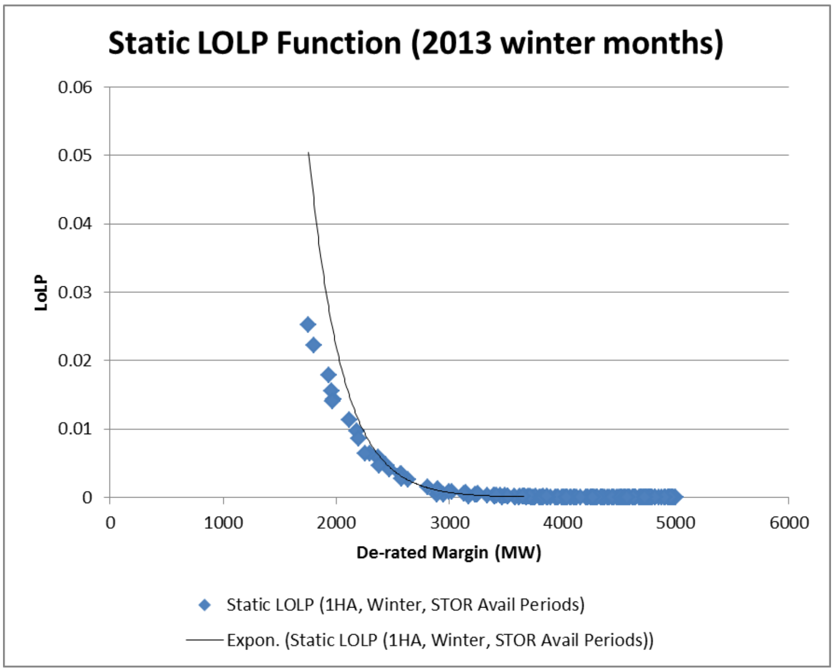


The model used to derive a static function is populated with LoLP values and expected de-rated margins calculated at Gate Closure for historical Settlement Periods.

The Workgroup considered that specific seasonal functions should be derived. For example, these may reflect the same summer/winter split as proposed by National Grid under the proposed LoLP function, or it may be split by BSC Season. The function for each period of time would be calculated using historical data from the same periods in the previous two years. *For example a function for the winter 2015/16 BSC Season would be calculated based on historic data from winter 2013/14 and winter 2014/15.*

The mathematical nature of the function has yet to be determined. The following charts illustrate actual LoLP values and de-rated margins during the summer and winter months of 2013, excluding Settlement Periods that are not STOR Availability Periods, and an exponential trend line. The trend line represents a function that 'fits' the historical data. More work is required to agree the parameters and variables for each function (e.g. what periods of time/seasons should be modelled, whether Settlement Periods outside of STOR Availability Periods should be left in the model) and to determine the most appropriate mathematical function to fit the LoLP and de-rated margin data.





A function for a particular period of time would be produced on a rolling basis following completion of the previous year, and published at an agreed lead time before the next period of time beginning*. For example a function for the winter 2016/17 BSC Season would be calculated following completion of winter 2015/16 based on the winter 2014/15 and winter 2015/16 data, and published at an agreed lead time ahead of the start of winter 2016/17.*

Calculation of the function

When producing a function, the Transmission Company will use historical LoLP values and de-rated margin data originally calculated using the method detailed in Section 1, at the one hour ahead (Gate Closure) point. The Transmission Company would calculate these LoLP values for all Settlement Periods in the historical data range.

Publication of the function and forecasted de-rated margin

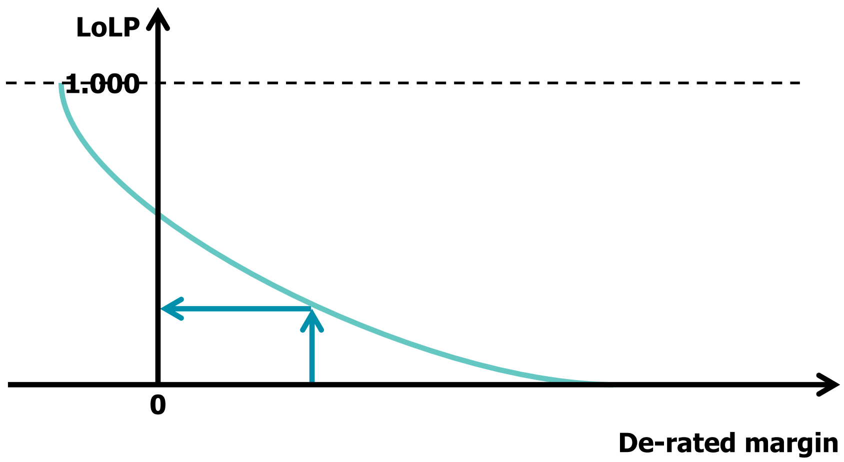
All functions would be published on the Balancing Mechanism Reporting Service (BMRS) at the agreed lead time for participants to access.

A forecasted value of de-rated margin for each Settlement Period will also be produced by the Transmission Company in the run-up to each Settlement Period, and this would also be published on the BMRS at agreed intervals. For example the proposed solution for P305 proposes to publish Indicative LoLP values at day-ahead and at eight, four and two hours ahead of real-time. These intervals could be used to publish forecast de-rated margin.

No Indicative LoLP values would be published under this solution. Participants would instead be able to look up the forecasted values of de-rated margin and use the published static function to derive the LoLP value for a particular Settlement Period.

Determining the Final LoLP value for a Settlement Period

The Final LoLP value for a given Settlement Period would be determined based on the forecasted de-rated margin at a given point in time, as illustrated below.



At this stage, the Workgroup has not agreed how far ahead of a given Settlement Period this determination point should be, but is considering the following four options:

- **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.

In any event, the Final LoLP value for a given Settlement Period would be published on the BMRS as soon as reasonably practical following determination, and would not be updated for any developments that may subsequently occur.

4 Workgroup's Historical Analysis

Historical analysis

ELEXON has undertaken a comprehensive piece of analysis on behalf of the Workgroup, which it has been unable to complete before this consultation was issued. A summary of the results will be published separately on the P305 page of our website in due course.

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

Ofgem's impact assessment accompanying the Final Policy Decision outlines the qualitative, quantitative and historic & forward-looking modelling analysis conducted to support the EBSCR. This analysis is ultimately motivated by economic theory, and tested by stakeholder feedback and the quantification of effects where possible. This Section presents a summary of Ofgem's key findings in relation to efficiency and competition.

Efficiency

In terms of balancing efficiency, theory suggests the package of reforms will lead to more efficient balancing behaviour by market participants in response to different system conditions, both in the short term and the long term. Quantitative analysis suggests (balancing efficiency) annual savings to consumers of approximately £30m by 2030 as a result of the industry facing cash-out charges that are more reflective of the costs incurred by the System Operator (SO).

In terms of wider wholesale market efficiency and efficiency in security of supply, theoretical evidence suggests that existing cash-out prices do not accurately reflect the value consumers place on flexibility and scarce electricity, which could be dampening signals for flexible demand, generation and new flexible technologies to be brought forward. Reforms aim to correct this failure. Although Ofgem has been unable to quantify some of these effects (and may therefore understate the benefits of reform), its modelling supports its conclusions that reform will lead to sharper price signals, particularly during tight margins, and that this should reduce the cost of capacity adequacy, driving efficiency in security of supply.

Cash-out reform is one of the potential factors that, by addressing missing money, may enable exit from the Capacity Mechanism (CM) in the future. The analysis for the Draft Policy Decision Impact Assessment shows that in the absence of the CM, cash-out reform would improve security of supply as well as efficiency.

Finally, forward modelling suggests reform may drive modest increases in consumer bills in the short-run, and a sustained reduction in bills over the medium and long-term, and a total improvement in consumer welfare of between £200m-£435m by 2030.

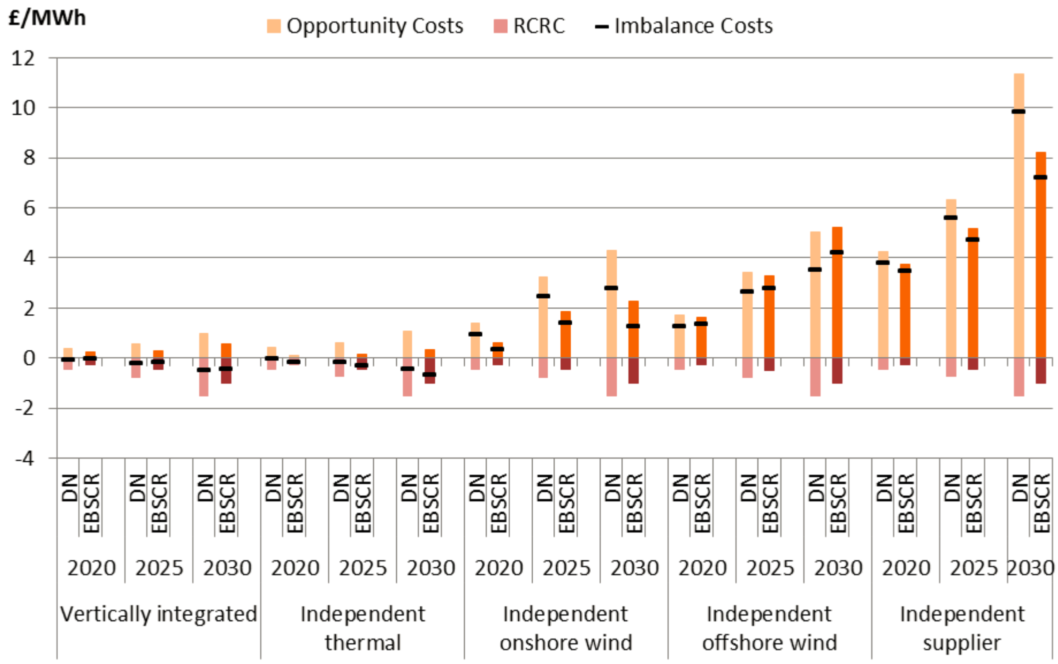
Competition

Theory suggests reform allows Parties best able to manage their energy imbalances to gain a competitive advantage according to the value delivered to the consumer, and thereby ultimately support free and fair competition.

Theory suggests that reform removes inefficiencies that may limit the potential for some Parties, in particular those offering services that facilitate flexibility and balance (such as Demand Side Response (DSR) or storage), to participate in the wholesale electricity market, and may thereby remove a distortion that undermines incentives for these Parties to enter and participate.

Sharper cash-out prices could be expected to disadvantage small independent Parties to the greatest extent, owing to the fact that historically they have incurred proportionally higher imbalance volumes. However, as described in Ofgem's impact assessment, small independent Parties have reducing imbalances relatively often, and will therefore benefit relatively more from a single price. Forward-looking and historical modelling suggests they will likely benefit from reforms overall as a result.

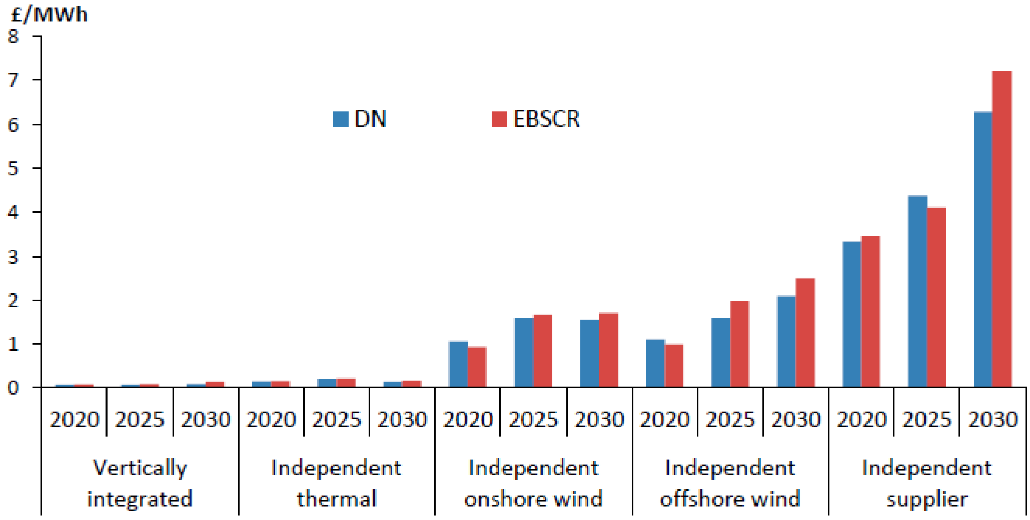
In terms of distributional impacts, forward modelling suggests the simulated impact of reform on the costs that Parties face in the future is favourable in each spot year (2020, 2025 and 2030) for independent Suppliers, independent thermal generators, offshore wind generators (with the exception of 2030) and onshore wind generators. While modelling suggests vertically integrated Parties will see an increase in imbalance charges, they will still face negative imbalance costs in every spot year (i.e. will remain net beneficiaries, owing to Residual Cashflow Reallocation Cashflow (RCRC) receipts). This is depicted in the figure below showing expected opportunity costs[1], RCRC and imbalance costs[2] per unit of credited energy in 2020, 2025 and 2030 under both the current (do nothing) and EBSCR arrangements, for different Party types.



In terms of operational risk, forward modelling suggests that expected volatility of credit requirements is likely modestly to increase as a result of reform. See the figure below which shows expected volatility in credit requirements in 2020, 2025 and 2030, under both the current (do nothing) and EBSCR arrangements for different Party types.

[1] Opportunity costs are the difference between the amount a Party pays for being out of balance (imbalance charge) and what it would have paid if it had traded out its position intraday. This metric reflects the cost of being out of balance.

[2] Imbalance costs are defined in this chart as the net of opportunity costs and RCRC.


£/MWh
8
7
6
5
4
3
2
1
0
DN
EBSCR
2020
2025
2030
Vertically integrated
Independent thermal
Independent onshore wind
Independent offshore wind
Independent supplier

6 Detailed Solution Requirements

This Section contains the detailed requirements for the P305 Proposed Modification, updated to account for any amendments to the proposed solution since the Impact Assessment was issued.

Area A: PAR value

Requirement A1	
The value of PAR will be set to 50MWh.	
A1.1	The Settlement Administration Agent (SAA) (Business Process Outsourcing (BPO) service provider) will set the value of the Price Average Reference (PAR) within central systems to 50MWh effective from the P305 Implementation Date. This value will apply to all Settlement Days from the P305 Implementation Date onwards.
A1.2	Participants who store the value of PAR within their internal systems will need to update this value effective from the P305 Implementation Date.

Requirement A2	
The value of RPAR will be set to 1MWh.	
A2.1	The SAA (BPO service provider) will set the value of the Replacement PAR (RPAR) within central systems to 1MWh effective from the P305 Implementation Date. This value will apply to all Settlement Days from the P305 Implementation Date onwards.
A2.2	Participants who store the value of RPAR within their internal systems will need to update this value effective from the P305 Implementation Date.

Requirement A3	
The value of PAR will be set to 1MWh effective from 1 November 2018 (November 2018 BSC Systems Release).	
A3.1	The SAA (BPO service provider) will set the value of PAR within central systems to 1MWh effective from 1 November 2018. This value will apply to all Settlement Days from 1 November 2018 onwards.
A3.2	Participants who store the value of PAR within their internal systems will need to update this value effective from 1 November 2018.

Area B: Single imbalance price

Requirement B1	
If the NIV value is greater than zero in a given Settlement Period, the SBP will be calculated according to the Main Price calculation and the SSP will be set equal to the SBP.	
B1.1	For any Settlement Period on or after the P305 Implementation Date for which the Net Imbalance Volume (NIV) value is greater than zero, the Balancing Mechanism Reporting Agent (BMRA) (BPO service provider) and the SAA (BPO service provider) will calculate the System Buy Price (SBP) in accordance with BSC Section T4.4.2(a), referred to in this document as the Main Price calculation, including any amendments to this methodology introduced under Areas A, C or D.
B1.2	For any Settlement Period on or after the P305 Implementation Date for which the NIV value is greater than zero, the BMRA (BPO service provider) and the SAA (BPO service provider) will set the System Sell Price (SSP) to be equal to the SBP.
B1.3	For all Settlement Periods prior to the P305 Implementation Date, the values of SBP and SSP will continue to be calculated according to the methodology in force at the time (BSC Sections T4.4.2 and T4.4.3).
B1.4	Participants who calculate the values of SBP and SSP within their internal systems will need to update these methodologies accordingly effective from the P305 Implementation Date.

Requirement B2	
If the NIV value is less than zero in a given Settlement Period, the SSP will be calculated according to the Main Price calculation and the SBP will be set equal to the SSP.	
B2.1	For any Settlement Period on or after the P305 Implementation Date for which the NIV value is less than zero, the BMRA (BPO service provider) and the SAA (BPO service provider) will calculate the SSP in accordance with BSC Section T4.4.3(a), referred to in this document as the Main Price calculation, including any amendments to this methodology introduced under Areas A, C or D.
B2.2	For any Settlement Period on or after the P305 Implementation Date for which the NIV value is less than zero, the BMRA (BPO service provider) and the SAA (BPO service provider) will set the SBP to be equal to the SSP.
B2.3	For all Settlement Periods prior to the P305 Implementation Date, the values of SBP and SSP will continue to be calculated according to the methodology in force at the time (BSC Sections T4.4.2 and T4.4.3).
B2.4	Participants who calculate the values of SBP and SSP within their internal systems will need to update these methodologies accordingly effective from the P305 Implementation Date.

Requirement B3	
If the NIV value is equal to zero in a given Settlement Period, the SBP will be set to the Market Price and the SSP will be set equal to the SBP.	
B3.1	For any Settlement Period on or after the P305 Implementation Date for which the NIV value is equal to zero, the BMRA (BPO service provider) and the SAA (BPO service provider) will calculate the SBP in accordance with BSC Section T4.4.2(b) with reference to the Market Price.
B3.2	For all Settlement Periods on or after the P305 Implementation Date for which the NIV value is equal to zero, the BMRA (BPO service provider) and the SAA (BPO service provider) will set the SSP to be equal to the SBP.
B3.3	For all Settlement Periods prior to the P305 Implementation Date, the values of SBP and SSP will continue to be calculated according to the methodology in force at the time (BSC Sections T4.4.2 and T4.4.3).
B3.4	Participants who calculate the values of SBP and SSP within their internal systems will need to update these methodologies accordingly effective from the P305 Implementation Date.
B3.5	For all Settlement Periods, the BPO service provider will continue to calculate the Market Price as per BSC Section T4.3A and publish the Market Index Data on the ELEXON Portal in line with the current requirements.

Area C: Reserve Scarcity Pricing

Requirement C1	
A price for any BM or non-BM STOR action will be calculated and submitted into the Main Price calculation.	
C1.1	For each Settlement Period where a BM or non-BM STOR action (an action taken by the Transmission Company during the defined STOR Availability Windows) is taken, the action and an associated volume and price will be included in the Main Price calculation as though it was an ordinary Bid-Offer. These actions will be referred hereafter as STOR Actions and will be treated as Buy Actions within the Main Price calculation.
C1.2	The Transmission Company will submit each BM and non-BM STOR Action as an individual action to the BMRA (BPO service provider). Each STOR Action will be submitted to the BMRA using the BMRA-I002 'Balancing Mechanism Data' data flow as though it was any other Bid-Offer. The BMRA-I002 data flow will be updated so that all Bid-Offers will be accompanied by a flag to denote whether or not the action was a STOR Action. For each STOR action, the BMRA-I002 data flow must include the BM or non-BM STOR Name/ID, the volume instructed by the STOR Action, the Utilisation Price of the action (i.e. the System Action Price) and the start and end time of the action. STOR Actions will be reported to the BMRA no later than 15 minutes after the end of each Settlement Period the STOR Action relates to. The aggregated non-BM STOR information will be removed from the BMRA-I003 'System Related Data' data flow.

Requirement C1	
C1.3	In any Settlement Period within a STOR Availability Window, the price of each STOR Action will be calculated by the BMRA (BPO Service Provider) as the greater of: • The Utilisation Price of the STOR Action, as provided in the BMRA-I002 data flow; or • The RSP for that Settlement Period, calculated (subject to Requirements C3.4 and C3.5) as the product of the Final LoLP value for that Settlement Period (as calculated under Requirement C2.3) and the VoLL Price (as defined under Requirement D1). Where a STOR Action extends over the start or end time of a STOR Availability Window, the price will not be adjusted in any Settlement Period outside of the STOR Availability Window, and will always be the Utilisation Price.
C1.4	The BMRA (BPO service provider) will include any STOR Actions for a given Settlement Period at the price as calculated under Requirement C1.3 in the calculation of the corresponding indicative imbalance prices published on the BMRS.
C1.5	The BMRA (BPO service provider) will publish any STOR Actions within the Indicative System Price Stack Items on the BMRS with the instructed volume, the Utilisation Price, the STOR flag and, if it was applied to the STOR Action, the RSP for the relevant Settlement Period. These will be published at the same time as the indicative system imbalance prices for that Settlement Period. Only actions or the part of actions that take place within a STOR Availability Window will be marked as STOR Actions; parts of actions outside of a STOR Acceptance Window will be treated as though they were normal system actions.
C1.6	The BMRA (BPO service provider) will make available each STOR Action, the Utilisation Price and, where applicable, the RSP as calculated under Requirement C1.3 to the SAA (BPO service provider) through the BMRA-I007 data flow according to current requirements and timescales and in any event in time for the II Settlement Run.
C1.7	The SAA (BPO service provider) will include any STOR Actions for a given Settlement Period made available under Requirement C1.6 in the calculation of the imbalance prices in all Settlement Runs.
C1.8	The SAA (BPO service provider) will publish the details of all STOR Actions along with all other Bid-Offer data as part of the SAA-I014 data flow. Each STOR Action will include the instructed volume, the Utilisation Price, the STOR flag and, if it was applied to the STOR Action, the RSP for the relevant Settlement Period.

Requirement C2	
The Transmission Company will calculate the LoLP value for each Settlement Period.	
C2.1	The Transmission Company will calculate the LoLP for each Settlement Period on or after the P305 Implementation Date in accordance with the LoLP Calculation Methodology Statement established under Requirement C4.

Requirement C2	
C2.2	The Transmission Company will calculate Indicative LoLP values for a given Settlement Period at the following calculation points, using the most recent data available at that time: • A value will be calculated at 12:00 on each calendar day for all Settlement Periods up to the end of the next Operational Day (defined under the Grid Code as the period from 05:00 on one day to 05:00 on the following day) for which Gate Closure has not yet passed; and • A value will be calculated at eight, four and two hours prior to the Settlement Period start time (seven, three and one hour(s) prior to Gate Closure) for each individual Settlement Period.
C2.3	The Transmission Company will calculate a Final LoLP value for each individual Settlement Period at one hour prior to the Settlement Period start time (Gate Closure) for that Settlement Period, using the most recent data available at that time.
C2.4	If the Transmission Company is unable to calculate a particular LoLP value under Requirements C2.2 or C2.3 (e.g. due to system outage) then that particular value will be deemed to be null. No attempt to recalculate the value will be made until the next scheduled calculation point.
C2.5	The method for calculating a LoLP value will be contained in the Loss of Load Probability Calculation Statement established under Requirement C4. The statement will include any static parameters (defined values that would not change without review and modification of the Statement) to be used in the calculation of a LoLP value and identify, where applicable, the range of these values used to calculate LoLP values at the different lead times across Requirements C2.2 and C2.3. Any parameters for which it is agreed will be updated on an annual or similarly regular basis by the Transmission Company will not be included in the Statement but will be published in a location easily accessible by the public and this location and the agreed method by which these values will be reviewed and updated will be detailed in the Statement.

Requirement C3	
The Transmission Company will submit the LoLP for each Settlement Period to the BMRA.	
C3.1	The Transmission Company will submit all Indicative LoLP and Final LoLP values calculated under Requirement C2 to the BMRA (BPO service provider) as soon as reasonably practical after calculation but no later than 15 minutes following the calculation point at which the value was calculated. This will be submitted in a new BMRA-IXXX data flow, which will contain the calculated LoLP value, the Settlement Date and Period for which it applies, a flag to denote Indicative or Final value and a flag to denote whether an actual value was calculated or whether the Transmission Company was unable to calculate a value and therefore has set the value to 'null'. All LoLP values at a given calculation point will be included in a single flow (e.g. the flow submitted at 00:00 will contain the Final LoLP value for the Settlement Period starting at 01:00 and the Indicative LoLP values for the Settlement Periods starting at 02:00, 04:00 and 08:00. The flow submitted at 12:00 will also contain all of the day-ahead values calculated at that point).

Requirement C3	
C3.2	The BMRA (BPO service provider) will publish all Indicative LoLP and Final LoLP values for each Settlement Period on the BMRS as soon as reasonably practical but no later than five minutes following receipt from the Transmission Company. If a 'null' value is received for a particular lead time and Settlement Period, the BMRA will replace the 'null' value with the most recently calculated Indicative LoLP value for that Settlement Period. If no such value is available, a 'null' value will be reported on the BMRS for that Settlement Period for that lead time. All LoLP values will have an associated flag to denote if it is an actual value or a defaulted value.
C3.3	The BMRA (BPO service provider) will use the Final LoLP value received from the Transmission Company for a given Settlement Period in the calculation of the RSP performed under Requirement C1.3.
C3.4	In the event a null Final LoLP value is received for a given Settlement Period the Final LoLP value will default to the most recently calculated Indicative LoLP value received for that Settlement Period.
C3.5	In the event that no LoLP values have been produced at any calculation point for a given Settlement Period, the Final LoLP value will be deemed to be null and the RSP for that Settlement Period will be deemed to be zero.

Requirement C4	
The LoLP Calculation Statement will be established on the BSC Baseline Statement.	
C4.1	The LoLP Calculation Statement will be established on the BSC Baseline Statement as a Category 'n/a' document, equivalent to the Market Index Definition Statement.
C4.2	The BSC Panel will be responsible for maintaining this document. The Panel may delegate this responsibility to an appropriate Panel Committee.
C4.3	All changes to the LoLP Calculation Statement must be approved by the Authority.
C4.4	The LoLP Calculation Statement will be reviewed by the BSC Panel from time to time. The BSC Panel can delegate responsibility for carrying out the review. If carried out under delegated authority, any conclusions to this review and any accompanying recommendations will be put to the Panel for decision. The process for conducting this review will be approved by the Panel, but must include consultation with the industry. Any proposed changes arising from such a review will not be required to go through the relevant BSC Change processes but will be submitted directly to the Authority for approval.
C4.5	Any consequential amendments to the Statement as a result of an approved BSC Modification or Change Proposal will be presented to the BSC Panel, who will decide either to submit the proposed changes directly to the Authority for decision or to initiate a review of the document as per Requirement C4.4.

Requirement C5	
The BPA will no longer include costs associated with STOR option fees.	
C5.1	The Transmission Company will no longer include costs associated with STOR option fees in the calculation of the Buy Price Adjustment (BPA) for any Settlement Period on or after the P305 Implementation Date.
C5.2	The revised calculation of the BPA is detailed in Appendix 2 of the original Impact Assessment document.
C5.3	The Transmission Company will continue to send the calculated BPA to the SAA (BPO service provider) as current.

Area D: Value of Lost Load pricing for Demand Control actions

Requirement D1	
The VoLL parameter will be established and its value initially set to £3,000/MWh before rising to £6,000/MWh ahead of Winter 2018/19.	
D1.1	The VoLL parameter will be established and defined in the BSC.
D1.2	The VoLL value will be set to £3,000/MWh effective from the P305 Implementation Date.
D1.3	The VoLL value will be set to £6,000/MWh effective from 1 November 2018 (November 2018 BSC Systems Release).
D1.4	The SAA (Application Management and Development (AMD) service provider) will establish the VoLL parameter within central systems. This will be an editable parameter in similar style to the PAR parameter.
D1.5	The VoLL value will be reviewed by the BSC Panel from time to time or upon request by the Authority. This process is to be developed, but will be based on the existing MIDS review process and will allow for rationale or evidence provided by the Authority to be fed in where applicable. The Panel can delegate responsibility for carrying out the review. If carried out under delegated authority, any conclusions to this review and any accompanying recommendations will be put to the Panel for its final recommendation. The process for conducting this review will be approved by the Panel, but must include consultation with the industry. Any review should take account of any particular issues or evidence identified by the Panel or the Authority.
D1.6	The outcome of any VoLL review will be considered by the BSC Panel. If the Panel believes a change to the VoLL value should be progressed, it will have the ability to raise a corresponding Modification.
D1.7	Notwithstanding the outcome of a VoLL review, any participant eligible to do so may raise a Modification to propose a change to the VoLL value, which will follow the normal proceedings for a BSC Modification as laid out under BSC Section F, including setting an appropriate lead time for implementing any changes following approval or proposing an Alternative Modification.
D1.8	A VoLL value will apply to all Settlement Periods on all Settlement Days from and including its effective from date up to and including its effective to date, which will be the day prior to a revised VoLL value taking effect.

'Top-down' and 'bottom-up' processes

Requirements D2-D4 detail the '**top-down**' approach for the Demand Control volume estimation processes.

Requirements D5-D9 detail the '**bottom-up**' approach for the Demand Control volume estimation processes.

Requirement D2	
Notification of the commencement and cessation of a Demand Control event will be published on the BMRS.	
D2.1	The Transmission Company will notify the BMRA (BPO service provider) of the start of any Demand Control Event using a Demand Control Instruction. A Demand Control Event includes any of the following: • Demand reduction instructed by the Transmission Company pursuant to Grid Code Section OC6.5, • Automatic Low Frequency Demand Disconnection pursuant to Grid Code Section OC6.6, and • Emergency Manual Disconnection pursuant to Grid Code Section OC6.7. An initiating Demand Control Instruction should be reported to the BMRA as soon as reasonably practical but no later than 15 minutes on a reasonable endeavours basis after the commencement of the event. A notification will contain: • the Demand Control Instruction Identification Number; • the Stage Number (which will be '1' in this first submission); • the Demand Control Event Type Flag; • the start date and time; • the end date and time (to be left null until the event ends under Requirement D2.3); • the Distribution System Operator (DSO) impacted; • a Demand Control estimate in MW based on the total level of Demand Control instructed; and • a System Management Action Flag (SMAF). A single notification per affected DSO will be submitted for this first stage of the Demand Control Event. The manner and format by which this information will be submitted will be agreed between the Transmission Company and the BMRA, but is expected to be in a new BMRA-IYYY data flow, which will also be used for submissions made under Requirements D2.2 and D2.3.
D2.2	The Transmission Company will notify the BMRA (BPO service provider) of any further stages of Demand Control instructed to a given DSO following any notification issued under Requirement D2.1. Any notification should use the same Demand Control Instruction Identification Number in all update instructions associated to the same Demand Control Event for a given DSO (e.g. an update to the MW Demand Control estimate based on instructions of further tranches of Demand Control or tranches of partial demand restoration). Updates should be sent to the BMRA as soon as reasonably practical but no later than 15 minutes on a reasonable endeavours basis after the Transmission Company initiates any further Demand Control event/action. This notification will contain: • the same Demand Control Instruction Identification Number as under Requirement D2.1; • an incrementally updated Stage Number; • the Demand Control Event Type Flag; • the start date and time of the additional instruction;

Requirement D2	
	• the end date and time (to be left null); • the DSO impacted; • a Demand Control estimate in MW based on the total level of additional Demand Control instructed during the stage being reported (this will be in additive format, with a positive number denoting additional volume instructed and a negative number denoting a reduction in the volume instructed); and • a SMAF flag.
D2.3	The Transmission Company will notify the BMRA (BPO service provider) of the end of any Demand Control Instruction as soon as reasonably practical but no later than 15 minutes on a reasonable endeavours basis after the cessation of the event. This notification will contain the Demand Control Instruction Identification Number used under Requirements D2.1 and D2.2 and the end date and time, with all other fields null.
D2.4	The BMRA (BPO service provider) will publish all notifications received on the BMRS as soon as reasonably practical but no later than five minutes of receipt from the Transmission Company.
D2.5	The Demand Control Event Type Flag field will enable the Transmission Company to individually identify each of the different Demand Control Event types identified in D2.1. For all automatic Low Frequency Demand Disconnection notifications the Transmission Company will leave the DSO Impacted field null and automatically set the SMAF to 'Yes'.
D2.6	A Demand Control Event will be deemed to commence at the earliest start date and time notified under Requirement D2.1 and cease at the latest end date and time notified under Requirement D2.3. Any Settlement Period during which the Demand Control event commenced, was active or ceased will be deemed to be a Demand Control Impacted Settlement Period.
D2.7	The BMRA (BPO service provider) will share all Demand Control Instructions received in accordance with Requirements D2.1-2.3 with the Supplier Volume Allocation Agent (SVAA) (BPO service provider), the SAA (BPO service provider) and the Central Data Collection Agent (CDCA) (BPO service provider), so that these BSC Agents know that the process for correcting imbalance positions (Requirements D5-D9) with respect to that event will be applied to those Settlement Periods. A new BMRA-IZZZ flow will be required to enable the BMRA to share Demand Control Instructions with the other BSC Agents.
D2.8	A consequential amendment will be required to the Grid Code to update arrangements relating to System Warning notifications in relation to Demand Control arrangements.

Requirement D3	
A volume of energy for each Settlement Period affected by a Demand Control event will be calculated for use in the Main Price calculation.	
D3.1	For each stage of a Demand Control Event notified in accordance with Requirement D2.1 or D2.2, the BMRA (BPO service provider) and the SAA (BPO service provider) shall determine a Demand Control Volume where the MW level is set equal to the Demand Control estimate in the Demand Control Instruction, the time shall be set equal to the start time of the Demand Control stage as notified in Requirement D2.1 or D2.2 as applicable and the Demand Control Instruction Identification Number and Stage Number shall be set to the corresponding numbers notified in Requirement D2.1 or D2.2 as applicable.
D3.2	For each stage of a Demand Control Instruction, the BMRA (BPO service provider) and the SAA (BPO service provider) shall create an End Point Demand Control Volume where the MW level is set equal to the Demand Control estimate in the Demand Control Instruction, the time shall be set equal to the end time of the Demand Control Instruction as notified in Requirement D2.3 and the Demand Control Instruction Identification Number and Stage Number shall be set to the corresponding numbers notified in Requirement D2.1 or D2.2 as applicable. If no notification has been received under Requirement D2.3 for a given Demand Control Event then the BMRA shall substitute the end time of the relevant Settlement Period in its place for the purpose of producing indicative Demand Control Volumes for use in calculating the indicative imbalance price for that Settlement Period.
D3.3	In respect of each Settlement Period the Demand Control Volume for each stage in a Demand Control Instruction shall be established by linear interpolation from the Start and End Point Demand Control Volumes calculated by the BMRA (BPO service provider) and the SAA (BPO service provider) for that Stage of the Demand Control Instruction.
D3.4	For each impacted Settlement Period the BMRA (BPO service provider) and the SAA (BPO Service Provider) will calculate two total Demand Control Volume for each Settlement Period by summing the individual Demand Control Instruction Stage volumes calculated in Requirement D3.3 applicable to that Settlement Period: • The System Demand Control Volume will consist of all notifications where the SMAF was set to 'Yes'; and • The Balancing Demand Control Volume will consist of all notifications where the SMAF was set to 'No'.
D3.5	The BMRA (BPO service provider) will complete this Requirement D3 in time for use in calculating the indicative imbalance prices. The SAA (BPO service provider) will complete this Requirement D3 in time for use in the Interim Information Settlement Run (II).

Requirement D4	
Demand Control actions will be submitted into the Main Price calculation by the BMRA and SAA.	
D4.1	For each Demand Control Impacted Settlement Period, the BMRA (BPO service provider) and the SAA (BPO Service Provider) will add the total System Demand Control Volume and Balancing Demand Control Volume calculated under Requirement D3.4 to the initial ranked set of system actions as two separate Demand Control Volume actions. These actions will be treated as though they are Buy Actions within the Main Price calculation.
D4.2	The price of any Demand Control Volume actions will be the VoLL value applicable in that Settlement Period. System Demand Control Volume actions will be automatically SO-Flagged.
D4.3	Any Demand Control Volume action will be subject to the normal tagging and flagging rules.
D4.4	Where Continual Acceptance Duration Limit (CADL) Flagging is performed in accordance with BSC Section T Appendix 3, the SAA (BPO service provider) will determine the Continual Acceptance Duration (CAD) using the commencement and cessation times provided by the Transmission Company under Requirement D2, and will use this to determine whether each Demand Control Volume action should be CADL flagged. Where CADL Flagging is performed in accordance with BSC Section T Appendix 4, a Demand Control Volume action will remain unflagged in all cases.
D4.5	Irrespective of whether a Demand Control Volume action is flagged and tagged, participants' imbalance volumes will still be corrected in accordance with Requirement D9.

Requirement D5	
DSOs will determine which MPANs were impacted by a Demand Disconnection event.	
D5.1	Any Host DSO impacted by a Demand Disconnection event (in accordance with Grid Code Sections OC6.5, OC6.6 or OC6.7) will be required to notify any Embedded DSOs operating within its areas as soon as reasonably practical upon it becoming known that the Embedded DSO's area has been impacted by the event.
D5.2	Following cessation of a Demand Disconnection event, each impacted DSO will, using its Supplier Meter Registration Service (SMRS), identify the Meter Point Administration Numbers (MPANs) in its area(s) (or connected to a Third Party Private Network which is connected to its network) that were impacted by the event.
D5.3	Using its SMRS, each DSO will notify each Half Hourly Data Collector (HHDC), Half Hourly Data Aggregator (HHDA), Non Half Hourly Data Collector (NHHDC) and Non Half hourly Data Aggregator (NHHDA) and the SVAA (BPO service provider) of all disconnected MPANs (whether import or export). This notice will also identify each disconnected MPAN's Profile Class and the start and end date and time (in local time) of the disconnection. This will be notified using a new DWWWW data flow.

Requirement D5	
D5.4	With reference to its SMRS, DSOs will not include in their notifications any MPANs that were registered as being de-energised, had been deregistered or that may have voluntarily reduced load or been disconnected (e.g. due to a Demand Side Response agreement) during the Demand Disconnection event.
D5.5	The DSO will submit all notifications no later than 5 Working Days (WD) following the cessation of the Demand Disconnection event to enable the calculation of Disconnection Volumes for use in the Initial Settlement Run (SF) and all subsequent Settlement Runs.
D5.6	A consequential change to the Data Transfer Catalogue (DTC) will be required to define the new DWWWW data flow.

Requirement D6	
The CDCA will estimate Demand Disconnection volumes for CVA BM Units.	
D6.1	The Transmission Company will inform the CDCA (BPO service provider) of any Directly Connected BM Units subject to Demand Disconnection. The Transmission Company will submit the BM Unit ID and the start and end date and time (in local time) of that disconnection in a new CDCA-IYYY data flow. This must be submitted no later than 5WD following the cessation of the Demand Control event.
D6.2	The relevant DSO will inform the CDCA (BPO service provider) of any Embedded BM Units subject to Demand Disconnection. The DSO will submit the BM Unit ID and the start and end date and time (in local time) of that disconnection in the same CDCA-IYYY data flow as in Requirement D6.1. This must be submitted no later than 5WD following the cessation of the Demand Control event.
D6.3	For each impacted Directly Connected or Embedded BM Unit in each impacted Settlement Period, the CDCA (BPO service provider) will agree the estimate of Half Hourly (HH) Demand Disconnection volume with the Lead Party of the BM Unit in accordance with BSCP03 Section 3.1 or 3.2 depending on Settlement Run.
D6.4	The CDCA (BPO service provider) will report the final estimates to the SAA (BPO service provider) using a new CDCA-IZZZ data flow. The timescales for submitting the CDCA-IZZZ data flow will be aligned with the existing timescales for CDCA-I014 'Estimated Data Report' data flow submission, and will only be sent for Settlement Periods that have been impacted by the event.

Requirement D7	
HHDCs will estimate Demand Disconnection volumes for HH MPANs.	
D7.1	Following receipt of a DWWWW flow, for each impacted HH MPAN in each impacted Settlement Period, the HHDC appointed to the MPAN will estimate the HH Demand Disconnection volume as Max {0, E – A}, where: E is an estimate of the metered data during the affected Settlement Period in normal conditions calculated in accordance with BSCP502 Appendix 4.2; and A is the validated actual Half Hourly Metered Data during the affected Settlement Period.

Requirement D7	
D7.2	The HHDC will send estimated disconnection volumes to the HHDA using a new DXXXX data flow. The DXXXX data flow will be based on the same structure as the D0036 'Validated Half Hourly Advances for Inclusion in Aggregated Supplier Matrix' data flow with the inclusion of a Settlement Period field and will be sent at the same time, but will only contain information in relation to Settlement Periods affected by a Demand Disconnection.
D7.3	Using the DXXXX data flows sent by HHDCs, HHDAs will aggregate the estimates of disconnected volumes to BM Unit and Consumption Component Class (CCC) level. For each CCC level it will estimate a corresponding volume of disconnection line losses.
D7.4	The HHDA will report the final estimates of CCC level disconnection volume and disconnection losses to the SVAA (BPO service provider) in a new DYYYY data flow. The DYYYY data flow will use the same structure as the D0040 'Aggregated Half Hour Data File' data flow and will be sent at the same time, but will only contain information in relation to Settlement Periods affected by a Demand Disconnection.
D7.5	A consequential change to the DTC will be required to define the new DXXXX and DYYYY data flows.

Requirement D8	
The SVAA will estimate Demand Disconnection volumes for NHH MPANs and adjust Suppliers' settled volumes.	
D8.1	Upon receipt of a DWWWW data flow, the SVAA (BPO service provider) will send a D0018 'Daily Profile Data Report' data flow to all NHHDCs for all Settlement Dates with one or more Demand Control Impacted Settlement Periods. This is to ensure all NHHDCs have details of Valid Measurement Requirement Period Profile Coefficients for use as part of Requirement D8.2 should they be required.
D8.2	Based on the details provided in the DWWWW data flow, NHHDCs appointed to disconnected MPANs will ensure that Annualised Advances (AAs) that are based on a Meter Advance including one or more Settlement Periods affected by a Demand Disconnection are 'corrected' so that the AA accurately reflects the effect of the disconnection. That is, the NHHDC will ensure that the sum of Valid Measurement Requirement Period Profile Coefficients for the Settlement Periods affected by the disconnection (determined from the D0018 data flow received from the SVAA) are subtracted from the sum of Daily Profile Coefficients ordinarily used to calculate the AA. No adjustment is made to the Meter Advance. Where a Settlement Period is only partially affected by a disconnection, the Period Profile Coefficient(s) for those Settlement Periods will be reduced by the proportion of the Settlement Period affected by the disconnection. 'Corrected' AAs will then be treated like any other AA and are sent to NHHDAs according to existing rules, using the D0019 'Metering System EAC/AA Data' data flow.

Requirement D8	
D8.3	Using the DWWWW data flow, for all impacted Non Half Hourly (NHH) MPANs in each Demand Control Impacted Settlement Period, NHHDAs appointed to those MPANs will for each combination of Supplier, Profile Class, Distributor, Line Loss Factor Class (LLFC), Standard Settlement Configuration (SSC) and Time Pattern Regime (TPR) sum the associated Estimated Annual Consumptions (EACs) and AAs, provide MPAN counts and include details of the start and end times of disconnection in new DZZZZ data flow for Settlement Days impacted by the event. The DZZZZ will use the same structure as the D0041 'Supplier Purchase Matrix Data File' data flow and will be sent at the same time, but will only contain information in relation to Settlement Days affected by a Demand Disconnection. The D0041 data flow will continue to be sent according to existing requirements, i.e. it will sum all MPANs' (whether disconnected or not) EACs and AAs ('SPM' group). The usual aggregation and defaulting rules will apply to each MPAN.
D8.4	Based on the details in the DZZZZ data flow sent by the NHHDA, the SVAA (BPO service provider) will determine the impacted Settlement Periods, and for each impacted Settlement Period will profile the Total EAC or Total AA using Valid Measurement Requirement Period Profile Coefficient data relevant to the affected Settlement Periods. This will determine a proportion of the annual volume of energy relevant to each affected Settlement Period. The volumes of energy for each affected Settlement Period are an estimate of Disconnection Volume at Supplier, Profile Class and level of reading accuracy (i.e. based on an EAC or AA). In addition, Line Loss Factors (LLFs) relevant to the affected Settlement Periods are applied to the estimates of Disconnection Volumes to calculate a Disconnection Losses Volume at Supplier, Profile Class and level of reading accuracy. The calculation of Disconnection Volumes and Disconnection Losses Volumes will be made in line with existing rules for profiling and the application of line losses. The SVAA will scale those estimates according to the number of impacted minutes in the Settlement Period.
D8.5	The SVAA (BPO service provider) will aggregate the Disconnection and Disconnection Losses Volumes calculated under Requirement D8.4 by BM Unit and CCC. These volumes (the Supplier Demand Disconnection Adjustment Volumes) are used in relation to Requirement D9.1.
D8.6	The calculation of disconnection volumes in accordance with D8.4 and D8.5 will take place at each Settlement Reconciliation Run.
D8.7	The SVAA (BPO service provider) will process the Supplier Purchase Matrix Details reported in D0041 data flows as per usual, except in relation to Settlement Periods affected by a disconnection. That is, the SVAA will profile AA, EAC and Unmetered Supplies (UMS) consumption and generate estimates of losses associated to the profiled AA, EAC and UMS consumption. These volumes are then attributed to BM Units and CCCs.
D8.8	For Settlement Periods affected by a Demand Disconnection event, the SVAA (BPO service provider) will subtract the BM Unit and CCC level aggregate disconnection and losses volumes calculated under Requirement D8.5 from the equivalent BM Unit and CCC level volumes calculated under D8.7, prior to calculating the Grid Supply Point (GSP) Group Correction Factors for the Settlement Period.

Requirement D8	
D8.9	The SVAA (BPO service provider) will use the volumes calculated under Requirement D8.8 for all subsequent settlement calculations, including GSP Group Correction.
D8.10	All of the above steps under this Requirement D8 are to be completed as part of and in time for each Settlement Reconciliation Run.
D8.11	Disconnection volumes will also be reported in the SVAA reports (e.g. the Supplier Deemed Take report).
D8.12	A consequential change to the DTC will be required to amend the D0018 data flow to enable it to be sent to NHHDCs and to define the new DZZZZ data flow.

Requirement D9	
A volume for each Demand Disconnection event will be calculated for each impacted Settlement Period for use in adjusting Parties' imbalance positions.	
D9.1	The SVAA (BPO service provider) will sum the HH Demand Disconnection volumes across HH CCCs from Requirement D7.4 and the NHH demand disconnection volumes across NHH CCCs from Requirement D8.5 for each BM Unit.
D9.2	The Transmission Company will identify any MPANs where a STOR or Demand Side Balancing Reserve (DSBR) instruction had been dispatched and the volumes instructed from those MPANs in that Settlement Period and will notify these to the SVAA (BPO service provider) no later than 5WD following the cessation of the Demand Disconnection event.
D9.3	EMRS will identify any MPANs that fall under the CM and the volumes from those MPANs in that Settlement Period and will notify these to the SVAA (BPO service provider) along with the BM Unit that the MPAN is registered to, no later than 5WD following the cessation of the Demand Control event.
D9.4	EMRS will identify any BM Units that fall under the CM and the volumes from those BM Units in that Settlement Period and will notify these to the SAA (BPO service provider) no later than 5WD following the cessation of the Demand Control event.
D9.5	For MPANs which have been identified as being subject to Demand Disconnection under Requirement D5, the SVAA (BPO service provider) will sum the impacts identified under Requirements D9.2 and D9.3 for each BM Unit.
D9.6	The SVAA (BPO service provider) will deduct the volume calculated for each BM Unit under Requirement D9.5 from the volume calculated under Requirement D9.1. The SVAA will send the resulting involuntary demand control values for each impacted BM Unit to the SAA (BPO service provider) via an amended version of the SAA-I007 file.
D9.7	The SAA (BPO service provider) will sum the Demand Disconnection volumes calculated in D6.4 and D9.6 for each BM Unit. The SAA will include the resulting volumes in that BM Unit's Period BM Unit Balancing Services Volume (QBS).

Appendix 1: Glossary & References

Acronyms

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

Glossary of Defined Terms	
Acronym	Definition
AA	Annualised Advance
AMD	Application Management and Development *(service provider)*
BM	Balancing Mechanism
BMRA	Balancing Mechanism Reporting Agent *(BSC Agent)*
BMRS	Balancing Mechanism Reporting Service
BPA	Buy Price Adjustment *(value)*
BPO	Business Process Outsourcing *(service provider)*
CAD	Continual Acceptance Duration
CADL	Continual Acceptance Duration Limit *(parameter)*
CCC	Consumption Component Class
CDCA	Central Data Collection Agent *(BSC Agent)*
CM	Capacity Mechanism
DSBR	Demand Side Balancing Reserve
DSO	Distribution System Operator *(BSC Party)*
DSR	Demand Side Response
DTC	Data Transfer Catalogue
EAC	Estimated Annual Consumption
EBSCR	Electricity Balancing Significant Code Review
FFR	Fast Frequency Response
GSP	Grid Supply Point
HH	Half Hourly
HHDA	Half Hourly Data Aggregator *(Party Agent)*
HHDC	Half Hourly Data Collector *(Party Agent)*
II	Interim Information *(Settlement Run)*
LLF	Line Loss Factor *(value)*
LLFC	Line Loss Factor Class
LoLP	Loss of Load Probability *(value)*
MEL	Maximum Export Limit
MPAN	Meter Point Administration Number
NDZ	Notice to Deviate from Zero
NHH	Non Half Hourly

Glossary of Defined Terms	
Acronym	Definition
NHHDA	Non Half Hourly Data Aggregator *(Party Agent)*
NHHDC	Non Half Hourly Data Collector *(Party Agent)*
NISM	Notice of Insufficient System Margin
NIV	Net Imbalance Volume *(value)*
PAR	Price Average Reference *(parameter)*
PN	Physical Notification
RCRC	Residual Cashflow Reallocation Cashflow *(charge)*
RPAR	Replacement Price Average Reference *(parameter)*
RSP	Reserve Scarcity Price *(value)*
SAA	Settlement Administration Agent *(BSC Agent)*
SBP	System Buy Price *(value)*
SCR	Significant Code Review
SF	Initial Settlement *(Settlement Run)*
SMAF	System Management Action Flag
SMRS	Supplier Meter Registration Service
SO	System Operator
SSC	Standard Settlement Configuration
SSP	System Sell Price *(value)*
STOR	Short Term Operating Reserve
SVAA	Supplier Volume Allocation Agent *(BSC Agent)*
TPR	Time Pattern Regime
UMS	Unmetered Supplies
URRM	Upward Response Reserve Multiplier
VoLL	Value of Lost Load *(parameter)*
WD	Working Day

DTC data flows and data items

DTC data flows and data items referenced in this document are listed in the table below.

DTC Data Flows and Data Items	
Number	Name
D0018	Daily Profile Data Report
D0019	Metering System EAC/AA Data
D0036	Validated Half Hourly Advances for Inclusion in Aggregated Supplier Matrix
D0040	Aggregated Half Hour Data File
D0041	Supplier Purchase Matrix Data File

DTC Data Flows and Data Items	
Number	Name
DWWWW	*New data flow*
DXXXX	*New data flow*
DYYYY	*New data flow*
DZZZZ	*New data flow*

External links

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

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

External Links		
Page(s)	Description	URL
2	EBSCR page on the Ofgem website	https://www.ofgem.gov.uk/electricity/wholesale-market/market-efficiency-review-and-reform/electricity-balancing-significant-code-review
2, 20	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
19, 29	P305 page on the ELEXON website	http://www.elexon.co.uk/mod-proposal/p305/
19	ELEXON Portal *(a free login account is required to access this data)*	https://www.elexonportal.co.uk/
20	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