Detailed Assessment

P305 'Electricity Balancing Significant Code Review Developments'

Phase

Initial Written Assessment

Definition Procedure

Assessment Procedure

Report Phase

Implementation

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About This Document

This is Attachment A to the P305 Assessment Report. It provides additional detail of the Workgroup's analysis and discussions.

1 'Dynamic' 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. This is the function referred to as the 'dynamic' LoLP function.

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:

$$\text{LoLP} = P(Z - CR < 0)$$

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:

$CAP_i = \{ MEL_i \quad FPN_i \neq 0$

$\{ MEL_i \quad NDZ_i <$ Lead Time + 30 minutes **AND** unit desynchronised before MZT_i

$\{ 0 \quad$ 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 'Dynamic' 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**

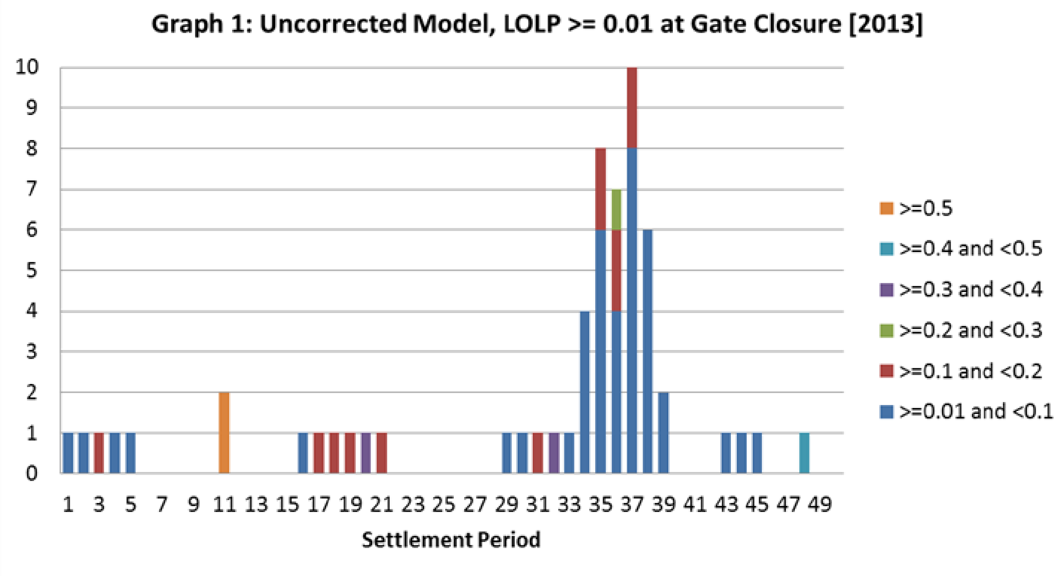
   This is the Baseline model as described above except that when calculating the available capacity the MELs are counted for any unit that, at the time of calculation, had been operating with a PN greater than zero within the last eight hours. The intention of this version is to capture the ability of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

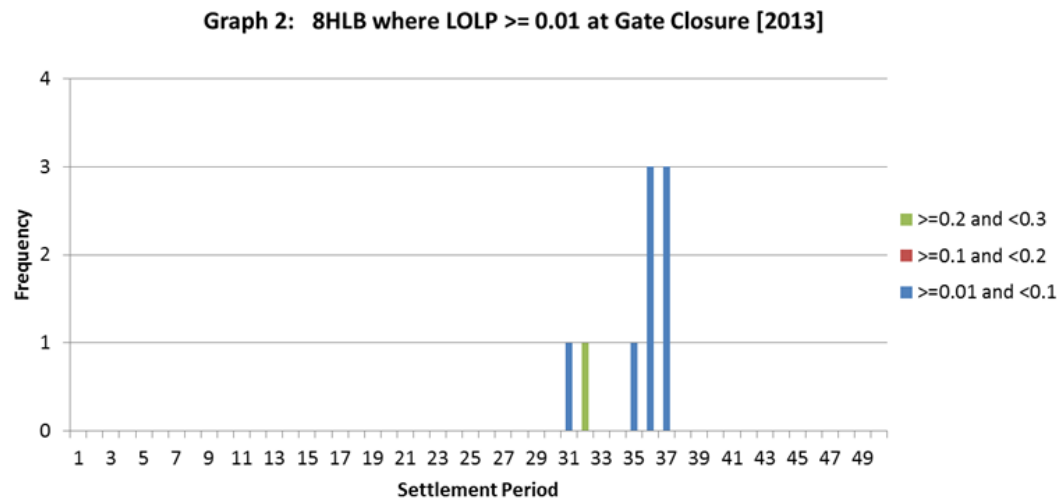
This analysis focuses on the **Baseline + 'Eight Hour Look Back' model**, as this was the model the P305 Workgroup agreed should be progressed. This model addressed the concerns of high LoLPs in overnight Settlement Periods that had been observed in previous iterations.

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.

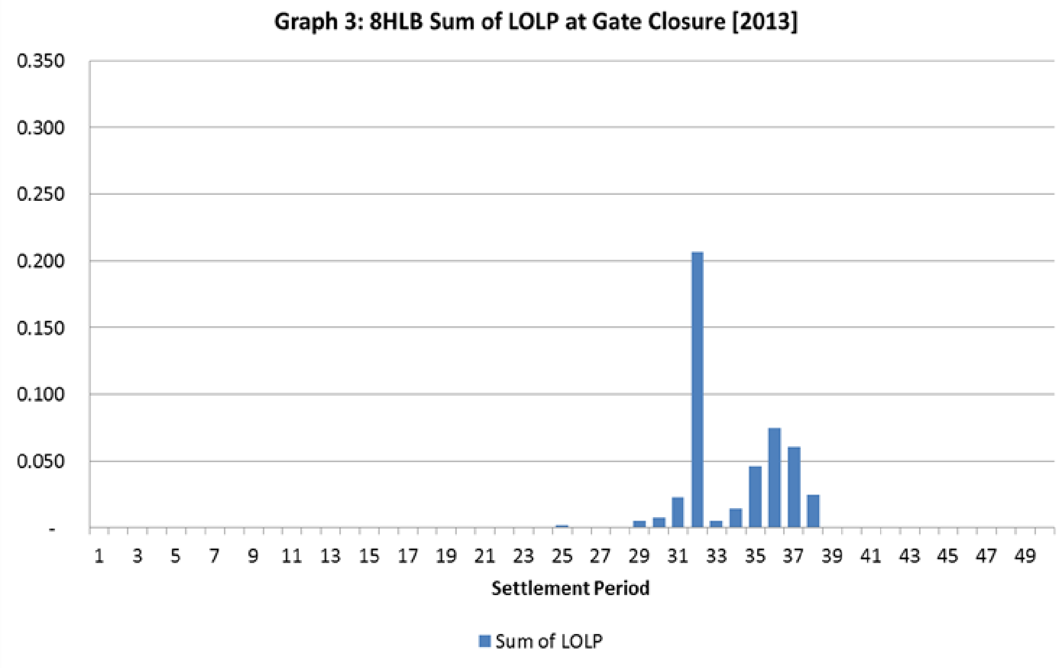
Summary of 2013 analysis

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.

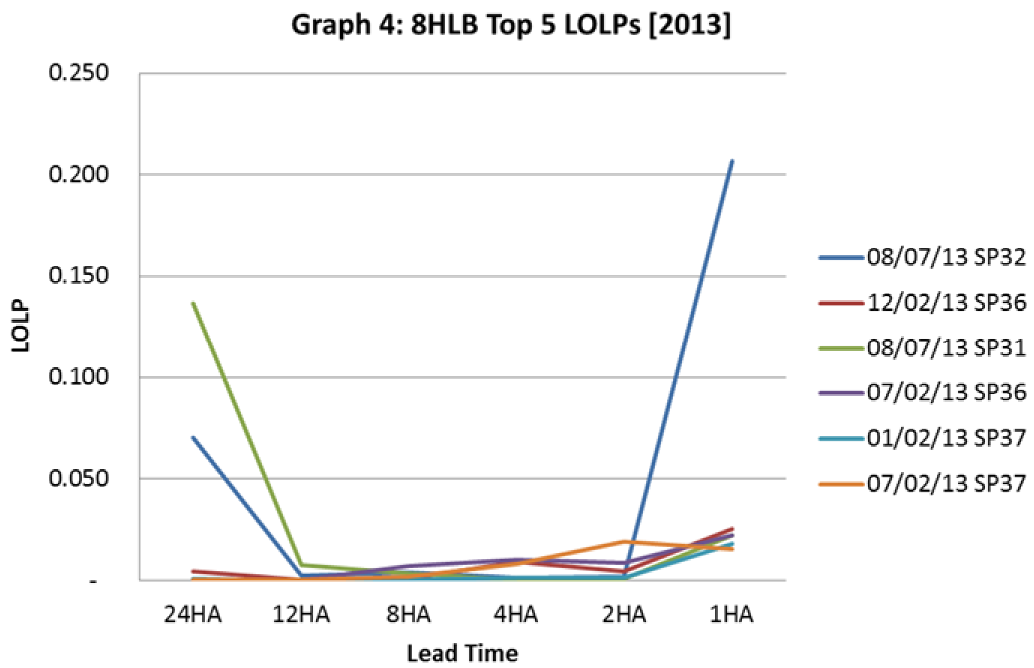




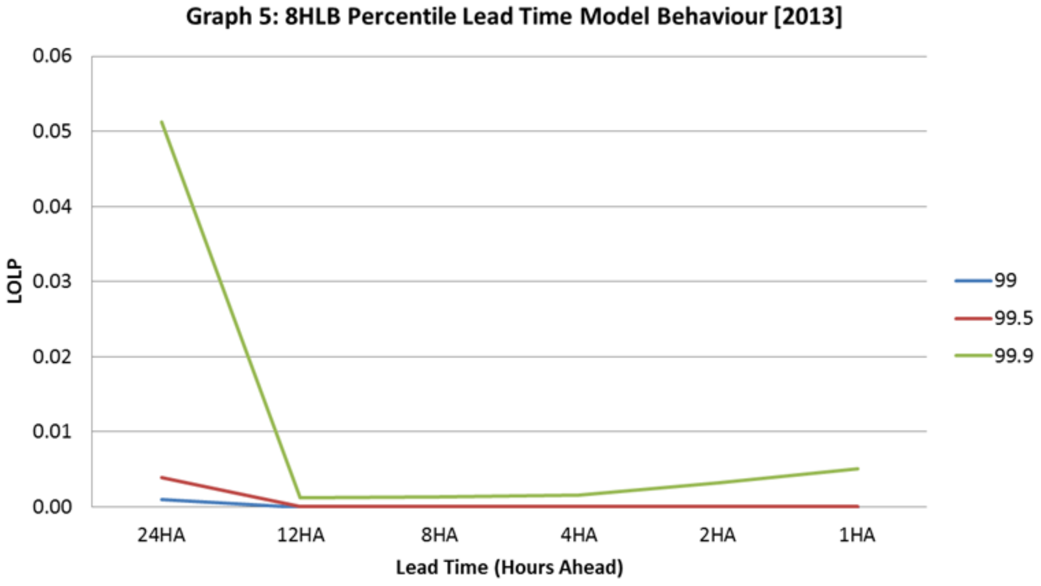
The summation of LoLP values per Settlement Period for the whole year is a useful metric in determining the overall behaviour of the model in reference to the time of day and whether high LoLPs typically occur over the demand peak as might be intuitively expected. However a singular event in which a 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.



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.



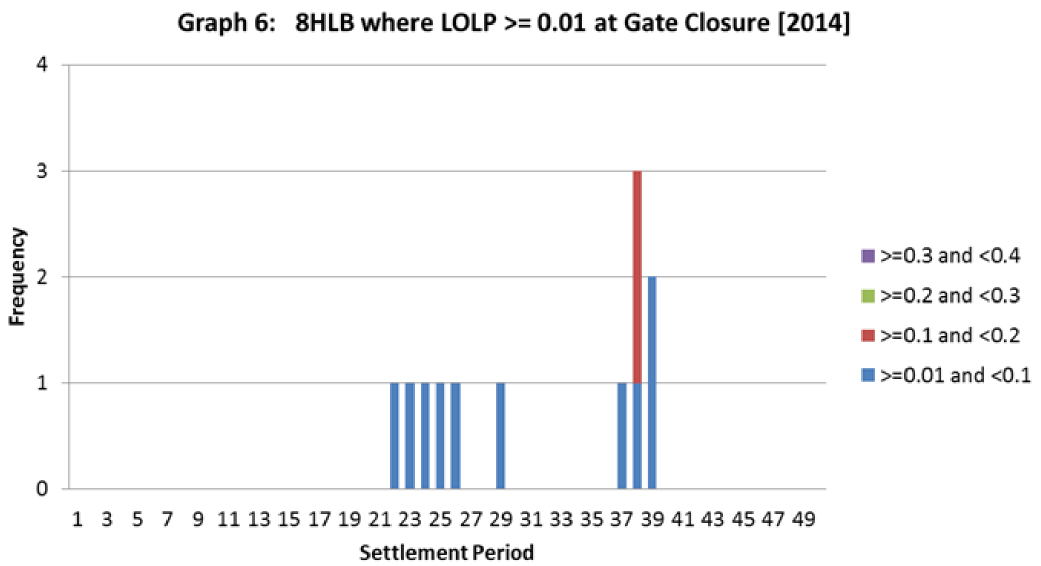
To represent typical model behaviour throughout the various lead times, percentiles are shown in Graph 5. These show that for 99.5% of Final LoLP values in 2013 the values are below 0.01 (1%) for all lead times from 24 hours ahead and transition smoothly between those lead times. The higher LoLP values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

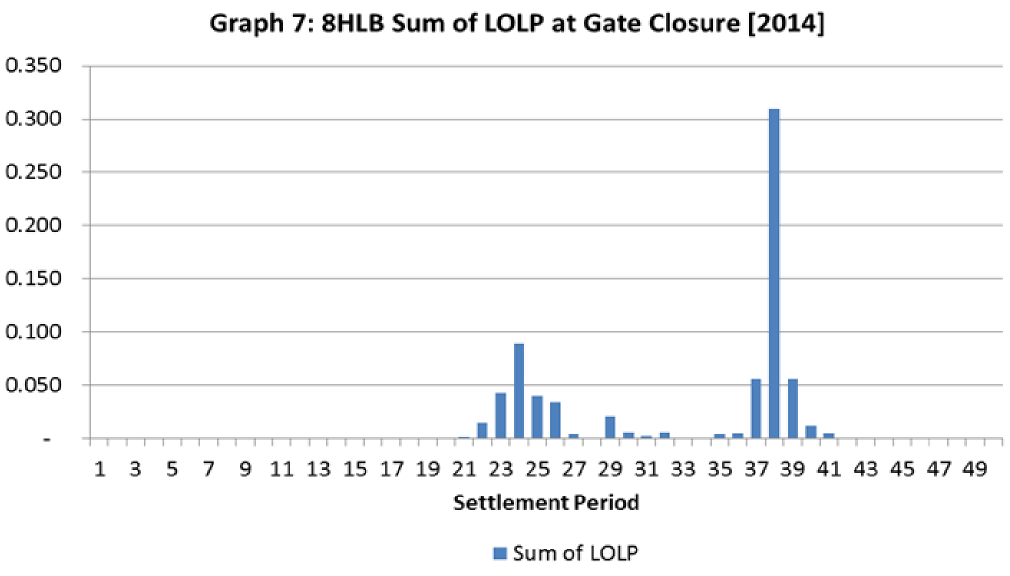


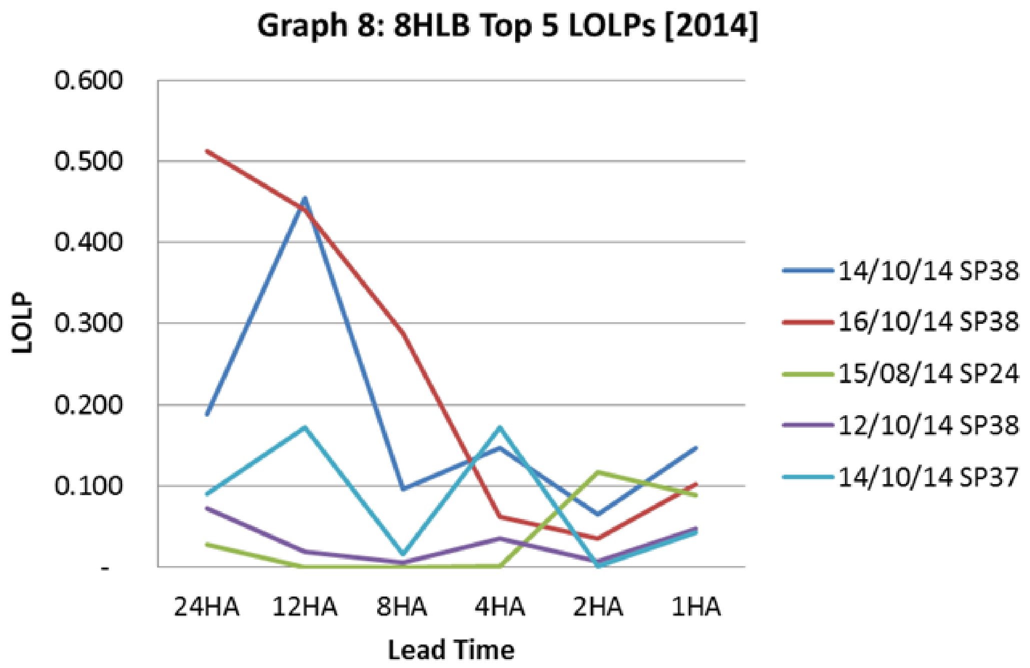
It should be noted that in the main, 2013 was a rather benign year and therefore one would not expect to see very many LoLP values above 0.1 (10%) and indeed any at a high level, reflected by the absence of any Notices of Insufficient System Margin (NISMs) over that period.

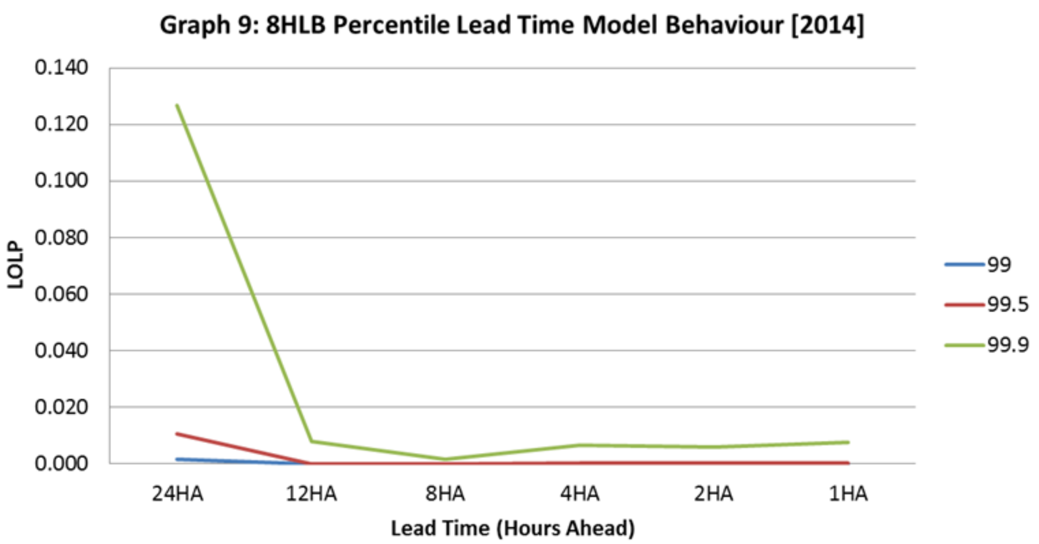
Summary of 2014 analysis

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.



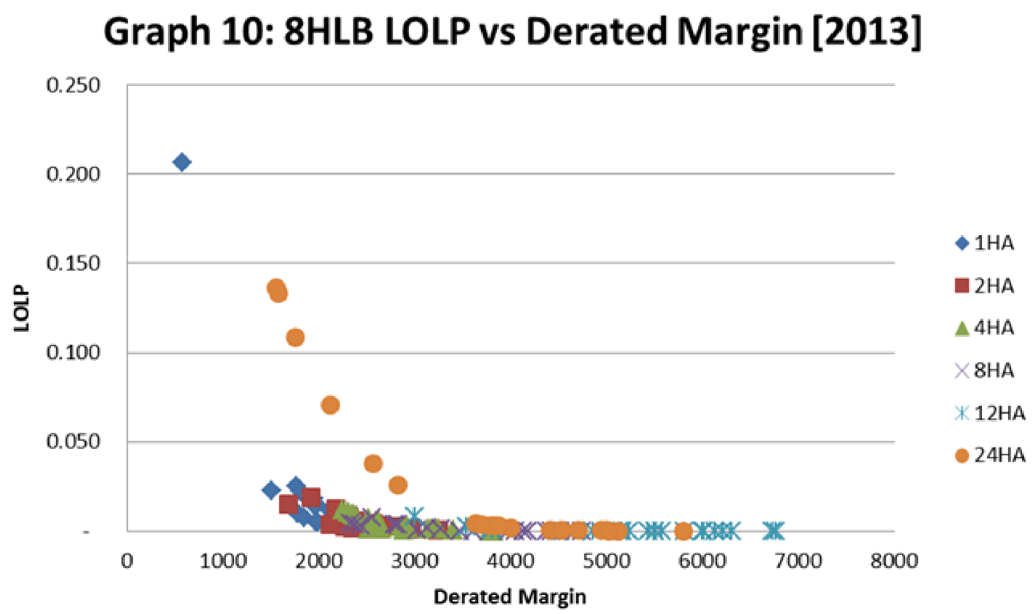

Graph 7: 8HLB Sum of LOLP at Gate Closure [2014]
0.350
0.300
0.250
0.200
0.150
0.100
0.050
-
1 3 5 7 9 11 13 15 17 19 21 23 25 27 29 31 33 35 37 39 41 43 45 47 49
Settlement Period
Sum of LOLP

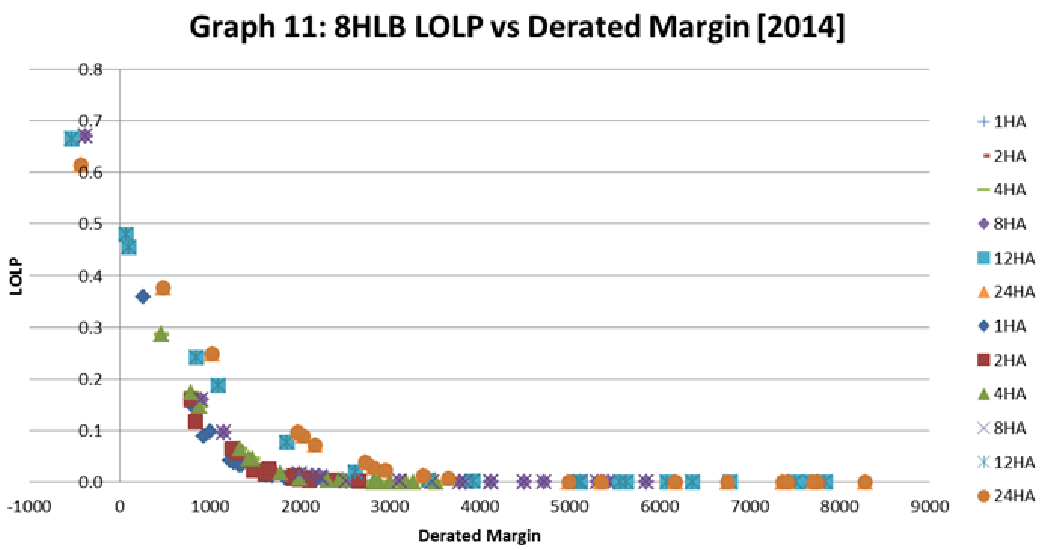

Graph 8: 8HLB Top 5 LOLPs [2014]
0.600
0.500
0.400
0.300
0.200
0.100
-
LOLP
24HA 12HA 8HA 4HA 2HA 1HA
Lead Time
14/10/14 SP38
16/10/14 SP38
15/08/14 SP24
12/10/14 SP38
14/10/14 SP37


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.





3 'Static' LoLP Function Straw Man Specification

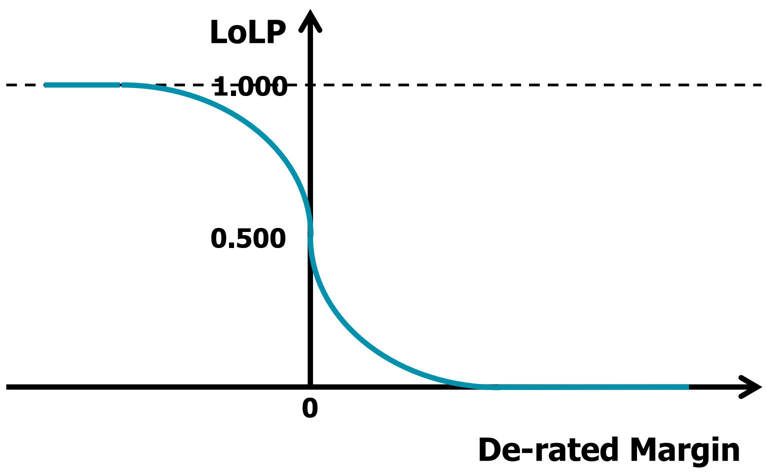
This Section summarises the 'static' LoLP function that has been developed by the Workgroup following consideration of the 'dynamic' function detailed in Section 1. Some details around this approach are still to be finalised, and no analysis has been undertaken to date to demonstrate the effect of creating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

Requirements of the function

The Workgroup's 'static' LoLP function will 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 curve will be based on applying an 'upside down normal cumulative distribution function' to the historical values. The historical values used will be the LoLP values and expected de-rated margins calculated at Gate Closure for historical Settlement Periods using the 'dynamic' function detailed in Section 1.

The diagram below illustrates the expected relationship between LoLP and de-rated margin that this would produce.



A curve will be calculated on an annual basis, to be effective from 1 April each year (with the exception of the first curve to be calculated, which will be effective from the P305 Implementation Date). Each curve will be produced and published three months in advance of its effective date.

The first curve will be calculated from the most recent 12 months of historic data available at that time, and the earliest date in this range will be noted. All subsequent curves will be calculated using all historic data available from this earliest date onwards at the time of calculation, meaning data would only ever be added to the pool of historic data, never removed.

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 'dynamic' function 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 curves would be published on the Balancing Mechanism Reporting Service (BMRS) three months ahead of a curve's effective date 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 would also 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, which would be used in the calculation of the RSP, would be determined based on the forecasted de-rated margin at Gate Closure.

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.

Executive summary

ELEXON has completed historical analysis that provides insight into the possible effects of P305 'Electricity Balancing Significant Code Review Developments' on imbalance prices and Parties' charges. This analysis was completed at the request of the Workgroup.

Our analysis focuses purely on recalculating imbalance prices and subsequent trading charges. It does not model any form of behavioural change that might be observed, should a change to the imbalance pricing arrangements be implemented.

Because of the sheer volume of output data produced by re-running imbalance calculations, this section contains a summary analysis of the key trends and does not provide a definitive view of all impacts and effects. To allow Parties to complete their own targeted analysis we have made raw data produced by our imbalance model (and used to produce the analysis below) available on the ELEXON Portal.

Key messages

As requested by the Workgroup, our analysis used 20 scenarios, which reflect different aspects of the P305 proposal (see below), to recalculate four years' worth of Settlement Period level imbalance prices and Party charges. The recalculation has used existing historical central data relating to accepted Bids and Offers, STOR actions, traded volumes and system margins, and incorporated additional data produced for P305 relating to Loss of Load Probabilities.

Overall impacts on prices

Whilst our analysis recalculated four years' worth of prices and charges, because sufficiently detailed STOR data was only available for 2013, the analysis in this section focuses on the effects observed in 2013.

In summary, we found:

- Maximum Main Price calculated in 2013 was £520.56/MWh – this was produced by scenarios assuming Price Average Reference (PAR) values of 1MWh and 50MWh, and Single Price but excluding Reserve Scarcity (RS) requirements (N.B. including RS requirements would have reduced the price to £496.28/MWh)[1].
    - The highest price calculated in other years was £705.86/MWh[2], assuming PAR 1 and Single Price but excluding RS requirements[3].
- Minimum Main Price calculated in 2013 was -£78/MWh in scenarios covering PAR values of 1MWh, 50MWh and 100MWh, Single Price and including RS requirements[4].

[1] Achieved on 4 November 2013 Settlement Period 35
[2] Achieved on 20 December 2010, Settlement Period 39
[3] An equivalent price including RSP requirements is not available as sufficiently detailed STOR action details were not available for periods other than during 2013
[4] Achieved on 31 August 2013 Settlement Periods 30 and 31, 6 October 2013 Settlement Period 28, 24 October 2013 Settlement Period 3 and 4, and 27 October 2013 Settlement Period 12

    - The lowest price calculated in other years was -£250/MWh[5], assuming PAR 1, Single Price but excluding RS requirements.

- Reducing PAR – consistently increases the System Buy Price (SBP) and reduces the System Sell Price (SSP), therefore widening the gap from Market Price. There also appears to be a more significant effect on prices of reducing PAR from 250 to 100. Lower PAR values also increase the occurrence of negative prices.

- Replacing Dual Prices with a Single Price – causes considerably more Reverse Price SBPs to be re-priced at SSP (than SSPs re-priced at SBP). However, the spread between extreme SBP and SSP Single Main Prices would be greater under P305 than the current spread between SBPs and SSPs with Market Price, which may have a detrimental effect on parties.

- Including Reserve Scarcity – re-pricing STOR actions to the RSP occurred infrequently and had little impact on Main Prices. However, inclusion of non-BM STOR actions and revised Buy Price Adjusters both increased in certain periods and reduced prices in other periods.

Overall impacts on Parties

In summary we found that:

- Replacing Dual Prices with a Single Price – improved all parties Imbalance Cash Flow positions. This may be because Parties are exposed to a more frequent and lower SSP Main Price on average.

- Reducing PAR – increases SBP and reduces SSP. Consequently improved Imbalance Cash Flow positions under a single price tended to diminish as PAR reduced.

- Net Positions – under P305 single price arrangements, Independent Suppliers and Independent Thermal generators are better off in all quarters and all PAR values. This is because imbalance charges are lower (and Residual Cashflow Reallocation Cashflow (RCRC) ends up as payments to Parties due to lower imbalance charges). Whereas Vertically Integrated Parties are worse off from much higher payments for RCRC (due to large metered positions used in the RCRC calculation), even though they benefit from decreased imbalance charges.

  Under the current dual price arrangements (with decreasing values of PAR), Vertically Integrated parties' net positions are better than under single price arrangements, because whilst their imbalance cash flows grow as PAR is reduced, the size of RCRC payments they receive increases faster.

- Distributional effects – our analysis shows that between 2010 and 2014, Independent Suppliers, particularly Renewable and Small and Medium Enterprise (SME) Suppliers, would have benefitted the most from the P305 reforms. That is, Independent Suppliers overall experienced an average reduction in net positions of ~£0.3/MWh. Independent Thermal parties also benefitted from an average reduction in net position of between ~£0.016/MWh and ~£0.043/MWh. Vertically Integrated parties did not benefit – they experienced an average increase in their net positions of ~£0.02/MWh.

[5] Achieved on 23 September 2011, Settlement Period 44

Workgroup requirements

As part of the assessment of P305, ELEXON recalculated imbalance prices and participants' historical imbalance charges between 15 February 2010 and 17 May 2014 using the different parameters and requirements being considered as part of the P305 Modification Proposal. This work has been completed at the request of the P305 Workgroup and has aimed to reproduce analysis similar to that requested as part of the development of P304 'Reduction in PAR from 500MWh to 250MWh'.

Whilst Ofgem produced a large body of analysis to support its EBSCR Final Decision, the P305 Workgroup considered that additional analysis was necessary to better understand the effects of the specific solution (and solution options) over time and on different parties. In general the purpose of the analysis is to provide greater insight into the potential effects of the developing P305 solution by recalculating historical imbalance prices and the subsequent impacts on parties' imbalance charges/positions according to twenty scenarios that reflect the different aspects and options of the modification proposal.

The use of twenty scenarios is in response to the Workgroup's requests that (i) different values of PAR should be analysed and (ii) the different core elements of the P305 proposal should be incrementally incorporated (i.e. prices and impacts should be calculated for P305 Area A only, reduction in PAR; then Areas A+B, reduction in PAR and Single Price; then Areas A+B+C etc). Further details of the scenarios and associated assumptions are described below.

Analysis: approach, scenarios and assumptions

ELEXON's analysis has been compiled by producing a model that enables the recalculation of imbalance prices and Party charges assuming different P305 scenarios. This model is populated with historical data covering activity between 15 February 2010 and 17 May 2014.

In order to satisfy the Workgroup's requirements, 20 scenarios were defined and modelled. Each scenario relates to an 'area' of the P305 proposal, as described in the Requirements (see Section 6 of the P305 Detailed Assessment, Attachment A to the P305 Assessment Procedure Consultation):

- Area A: the introduction of a reduced value of PAR;
- Area B: replaces the dual price approach with a single price;
- Area C: incorporates a value of Reserve Scarcity into the calculation of imbalance prices; and
- Area D: adds the cost of involuntary demand disconnection into the calculation of imbalance prices.

The detailed assumptions for each scenario are set out in the table below.

It is important to note that the scenarios simply reflect proposed changes in the method for calculating imbalance charges. ELEXON's analysis assumes that the behaviour of participants remained unchanged. Therefore participants' imbalance volumes will not have changed as a consequence of changes in expectation or price brought about by the proposed P305 proposal.

Table 1

P305 Scenarios				
Scenario	Area(s)	PAR	Single/Dual Price?	BPA/SPA covers STOR?
01	A	350MWh	Dual	Yes
02	A	250MWh	Dual	Yes
03	A	100MWh	Dual	Yes
04	A	50MWh	Dual	Yes
05	A	1MWh	Dual	Yes
06	A+B	350MWh	Single	Yes
07	A+B	250MWh	Single	Yes
08	A+B	100MWh	Single	Yes
09	A+B	50MWh	Single	Yes
10	A+B	1MWh	Single	Yes
11	A+B+C	350MWh	Single	No
12	A+B+C	250MWh	Single	No
13	A+B+C	100MWh	Single	No
14	A+B+C	50MWh	Single	No
15	A+B+C	1MWh	Single	No
16	A+B+C+D	350MWh	Single	No
17	A+B+C+D	250MWh	Single	No
18	A+B+C+D	100MWh	Single	No
19	A+B+C+D	50MWh	Single	No
20	A+B+C+D	1MWh	Single	No

In all cases, the Replacement PAR (RPAR) value has been set to 1MWh, the VoLL value has been set to £3,000/MWh, the Continual Acceptance Duration Limit (CADL) remains at 15 minutes, the De Minimis Acceptance Threshold (DMAT) remains at 1MWh and Market Index Data has been used to calculate the imbalance price where the Net Imbalance Volume (NIV) equals zero.

Please note that because no Settlement Period between February 2010 and May 2014 was impacted by a Demand Disconnection event. Consequently we have not modelled the scenarios that cover the application of Area D and so there are no specific results or analysis presented in this document.

Also note that whilst our analysis recalculated four years' worth of prices and charges, because sufficiently detailed STOR data was only available for the period 1 January 2013 to 4 November 2013, the analysis in this appendix focuses on the price effects observed in 2013 only.

Method

For each scenario, the following calculations were performed.

- The price calculation engine calculates the SBPs/SSPs using the required values of PAR and RPAR, and the current values of DMIN and CADL. It also records which was the main price, which is used for the "Single" price scenarios.
- The calculated prices were compared against the prices using the live acceptances and the values of PAR and RPAR to calculate a "change" or "delta" value between the scenario and the live scenario for System Buy Price and System Sell Price.
- For each Party Account, the Account Energy Imbalance volume was multiplied by the appropriate System Price Delta (either "Buy or "Sell, depending upon whether the Account was long or short in the Settlement Period).
- The total RCRC "pot" was calculated by summing the Account Imbalance Cashflow deltas for the date and period, and this is multiplied by (-1) and by the Account RCRP to calculate the RCRC delta for the Account in the Settlement Period.

References

Throughout this analysis the following non-BSC terms may be referred to:

- Live – refers to scenarios that are based on historical Bid-Offer Acceptance (BOA) details, already used in the calculation of imbalance prices.
- RSP – in the context of analysis illustrating the effects of a scenario, refers to the use of historical BOA details and additional details relating to non-BM STOR actions, Loss of Load Probabilities, adjusted BPAs and may also replace STOR utilisation prices with Reserve Scarcity Prices
- Single – in the context of analysis illustrating the effects of a scenario, refers to imbalance prices calculated assuming the proposed Single Price methodology
- Twin - in the context of analysis illustrating the effects of a scenario, refers to imbalance prices calculated assuming the existing Dual Price methodology
- Area(s) – typically refers to one or more of the four core elements of the P305 proposal

Effects on prices

This sub-section summarises the key impacts on imbalance prices caused by the application of the P305 scenarios described above. We have concentrated our analysis on highlighting the key trends rather than providing a detailed review of the effect of all scenarios.

Please note that at the time of re-running our model we were only able to use details of STOR actions for 2013 to produce the analysis in this consultation document, we have limited the following analysis to illustrate the effects on 2013 prices only. This is to enable unbiased comparison of the effects of P305 on prices with and without Area C (i.e. re-pricing STOR actions using RSP).

Reducing PAR

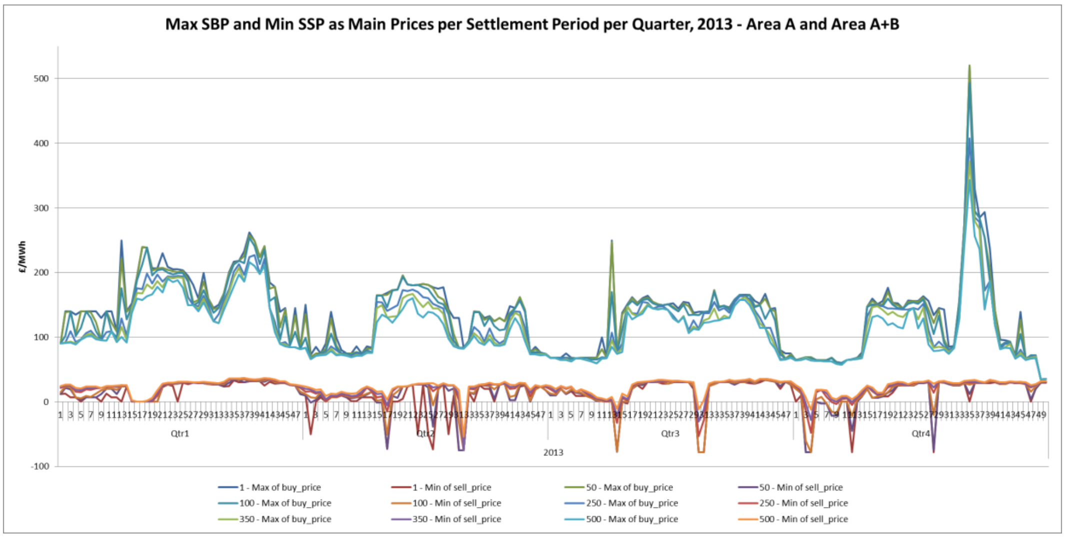
In general reducing the value of PAR had the effect of accentuating the calculation of Main Prices in two respects: reducing PAR meant (i) prices were typically higher and (ii) there was a wider range in prices.

Maximum, minimum and average prices

Figures 1 to 3 illustrate the range of prices generated by reducing values of PAR. Under P305 historical imbalance prices could have been as high as £705.86/MWh[6] and as low as -£250/MWh[7]. In both examples PAR was 1MWh and the RSP requirements had not been applied.

In 2013, reducing PAR from 350MWh to 1MWh resulted in average single Main Prices increasing by ~£2/MWh, average SBP Main Prices increasing by £8.5/MWh and average SSP Main Prices decreasing by £-1.87/MWh. Furthermore, reducing PAR 350 to PAR 1 lead to an increase in the maximum single and SBP Main Prices of £148.50/MWh, and a decrease in minimum SSP Main Prices of ~£-2/MWh.

Figure 1



In most cases, the calculation of prices caused by reduced levels of PAR can be explained by the fact that a smaller PAR results in a fewer number of BOAs with lower variation in price being included in the calculation of the Main Price. Consequently Main Prices calculated with a smaller PAR are more sensitive to individual large positive or negative actions (in terms of volume or price).

6 20 December 2010, Settlement Period 39

7 23 September 2011, Settlement Period 44

Figure 2

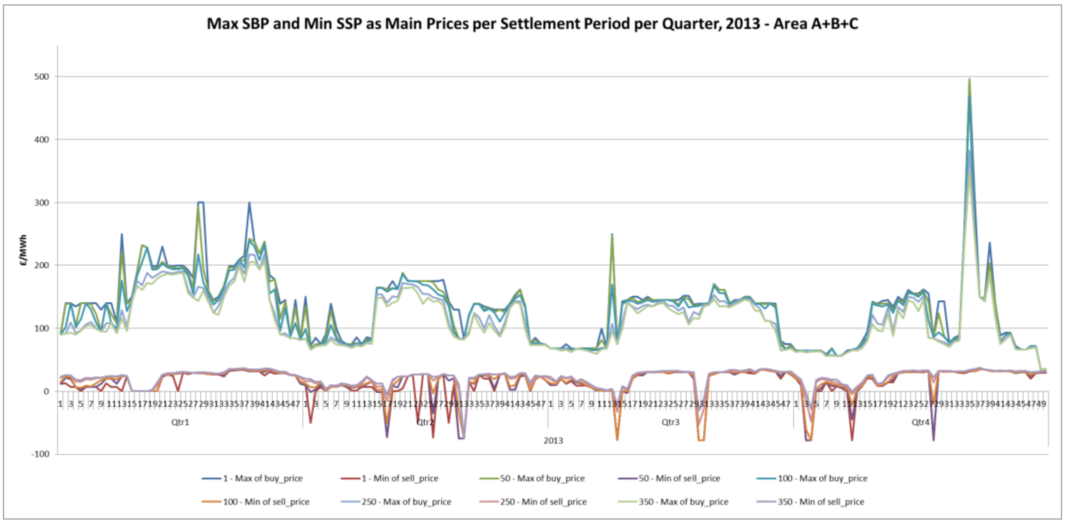
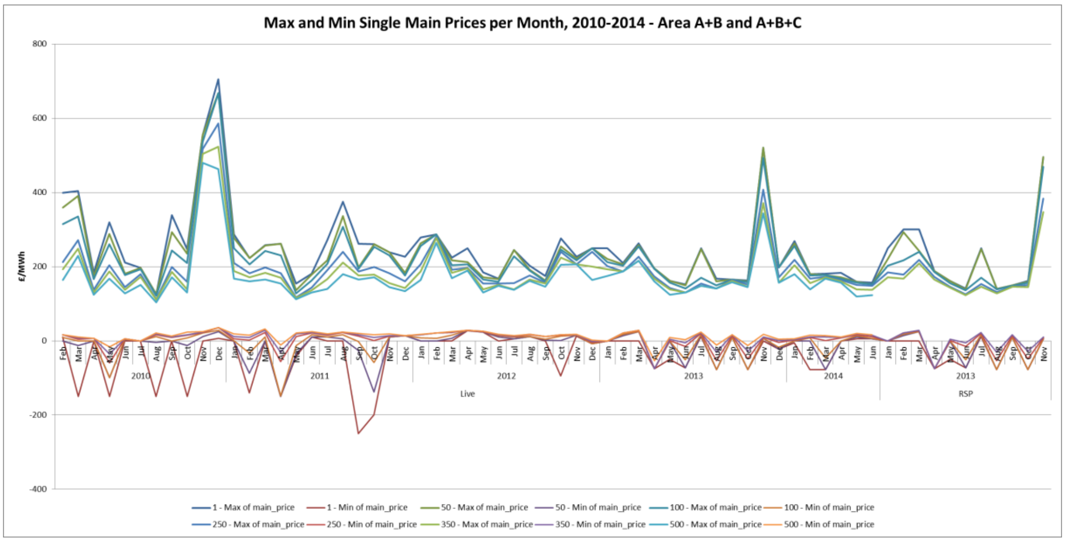


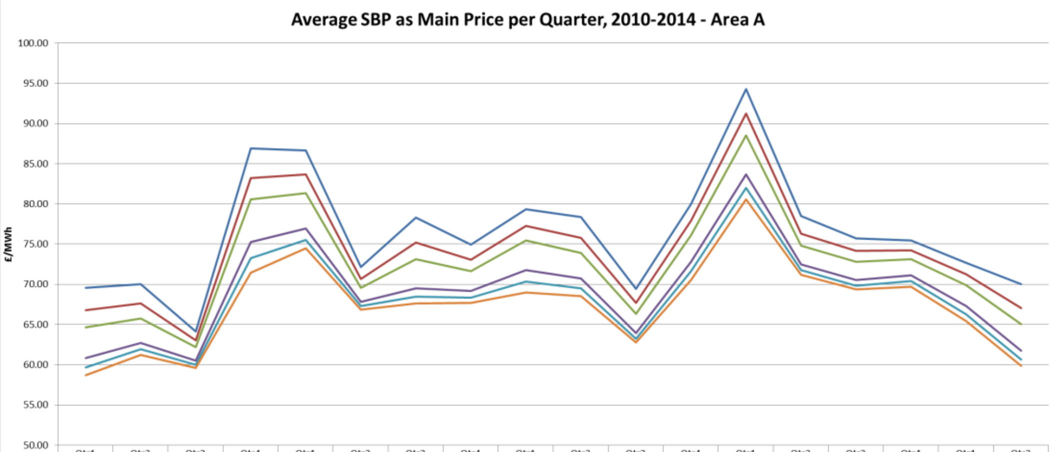
Figure 3



The change in price from one value of PAR to another appears to show that in a number of instances the reduction from PAR 250 to 100 results in a typically higher increase in prices than any other step change in PAR. This is most noticeable in Figure 4 below which demonstrates that that the average SBP per quarter between 2010 and 2014 shows a noticeable non-linear gap between prices set using PAR 250 and 100 compared to any other PAR, including 500. Figures 8, 10 and 11 also show that this tends to be most noticeable during the morning peak and evening peak hours during quarters 1 and 4, and in some cases the differences between PAR 350 and 250, and between PAR100 and 1 are very small by comparison.

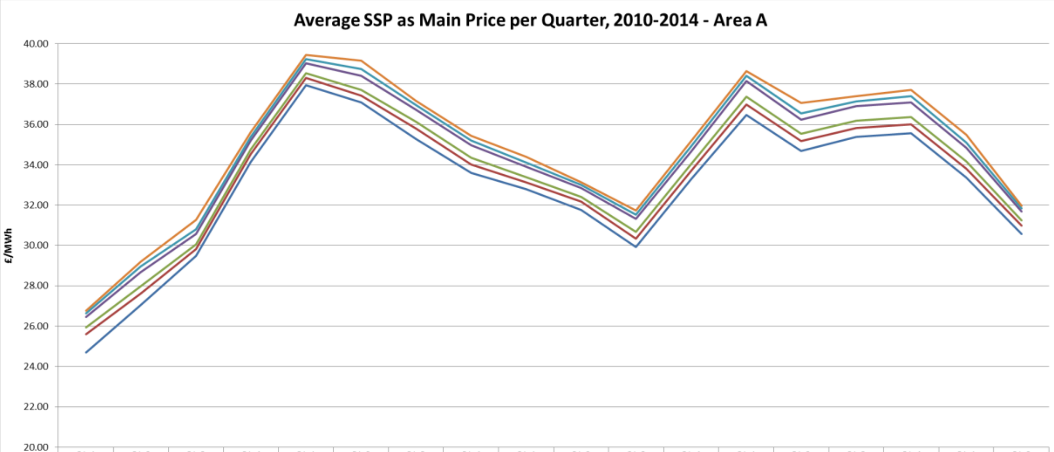
The gap between PAR 250 and PAR 100 prices may be explained by the fact that the average stack size of NIV-tagged BOAs is 296.61MW, with a standard deviation of 233.74MW. Therefore the likelihood of PAR tagging excluding BOAs increases if PAR is set lower than the average stack volume.

Figure 4



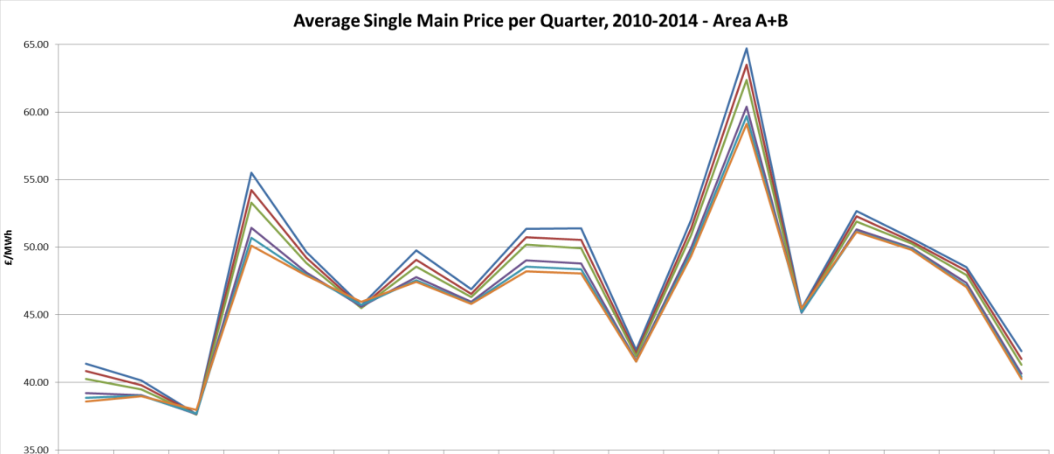
	Qtr1	Qtr2	Qtr3	Qtr4	Qtr1	Qtr2	Qtr3	Qtr4	Qtr1	Qtr2	Qtr3	Qtr4	Qtr1	Qtr2	Qtr3	Qtr4	Qtr1	Qtr2
	2010				2011				2012				2013				2014	
1	69.56	70.03	64.13	86.88	86.65	72.15	78.31	74.96	79.31	78.39	69.42	80.00	94.27	78.51	75.74	75.47	72.66	70.01
50	66.79	67.60	63.01	83.19	83.69	70.67	75.19	73.04	77.24	75.76	67.67	77.89	91.25	76.31	74.16	74.20	71.22	67.03
100	64.62	65.72	62.16	80.57	81.33	69.54	73.09	71.61	75.47	73.93	66.31	76.11	88.54	74.81	72.79	73.12	69.87	65.01
250	60.86	62.73	60.51	75.25	76.92	67.81	69.52	69.17	71.75	70.72	63.94	72.81	83.68	72.46	70.51	71.12	67.28	61.75
350	59.67	61.90	59.98	73.24	75.54	67.27	68.44	68.32	70.32	69.51	63.23	71.61	81.99	71.77	69.83	70.38	66.28	60.62
500	58.67	61.24	59.57	71.42	74.48	66.85	67.64	67.69	69.01	68.52	62.76	70.55	80.54	71.20	69.38	69.71	65.43	59.84

Figure 5



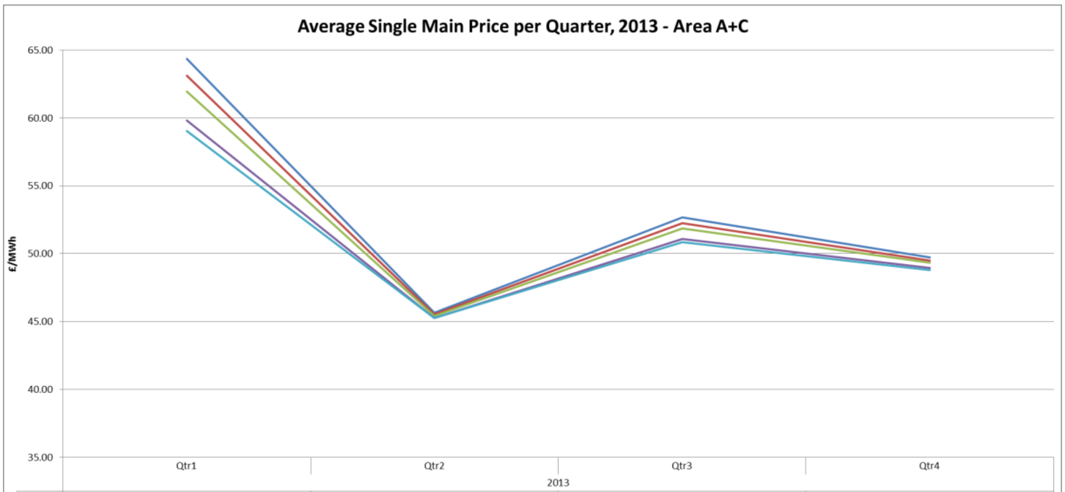
	Qtr1	Qtr2	Qtr3	Qtr4	Qtr1	Qtr2	Qtr3	Qtr4	Qtr1	Qtr2	Qtr3	Qtr4	Qtr1	Qtr2	Qtr3	Qtr4	Qtr1	Qtr2
	2010				2011				2012				2013				2014	
1	24.69	27.06	29.49	34.15	37.94	37.08	35.28	33.60	32.79	31.75	29.92	33.29	36.46	34.68	35.38	35.56	33.37	30.58
50	25.60	27.61	29.82	34.53	38.30	37.42	35.80	34.01	33.13	32.16	30.34	33.70	37.00	35.17	35.83	36.00	33.81	30.98
100	25.94	27.97	30.05	34.76	38.55	37.71	36.12	34.34	33.39	32.41	30.68	34.03	37.39	35.55	36.18	36.38	34.16	31.24
250	26.46	28.69	30.57	35.21	39.03	38.42	36.74	34.96	33.92	32.85	31.32	34.66	38.15	36.24	36.90	37.10	34.84	31.69
350	26.62	28.97	30.81	35.38	39.24	38.74	36.95	35.19	34.12	32.99	31.54	34.90	38.42	36.55	37.14	37.39	35.10	31.84
500	26.76	29.20	31.26	35.62	39.46	39.17	37.18	35.43	34.39	33.12	31.73	35.18	38.66	37.06	37.39	37.70	35.50	31.97

Figure 6



	Qtr1	Qtr2	Qtr3	Qtr4	Qtr1	Qtr2	Qtr3	Qtr4	Qtr1	Qtr2	Qtr3	Qtr4	Qtr1	Qtr2	Qtr3	Qtr4	Qtr1	Qtr2
	2010				2011				2012				2013				2014	
1	41.38	40.15	37.67	55.50	49.66	45.68	49.77	46.90	51.35	51.41	42.39	52.00	64.72	45.45	52.70	50.65	48.53	42.32
50	40.85	39.80	37.66	54.24	49.22	45.57	49.06	46.56	50.73	50.54	42.12	51.41	63.52	45.28	52.28	50.44	48.25	41.72
100	40.26	39.48	37.63	53.31	48.84	45.51	48.57	46.32	50.18	49.91	41.93	50.89	62.39	45.19	51.89	50.26	47.94	41.30
250	39.20	39.06	37.64	51.42	48.15	45.63	47.78	45.96	49.01	48.81	41.62	49.94	60.40	45.14	51.32	49.96	47.35	40.65
350	38.86	39.00	37.70	50.71	47.98	45.73	47.55	45.84	48.56	48.38	41.54	49.61	59.72	45.20	51.17	49.86	47.13	40.41
500	38.58	38.96	37.95	50.12	47.89	45.96	47.44	45.80	48.21	48.04	41.53	49.35	59.14	45.44	51.12	49.80	47.05	40.27

Figure 7



	Qtr1	Qtr2	Qtr3	Qtr4
1	64.38	45.67	52.69	49.73
50	63.12	45.52	52.25	49.50
100	61.94	45.41	51.85	49.33
250	59.84	45.26	51.09	48.95
350	59.05	45.28	50.85	48.78

Figure 8

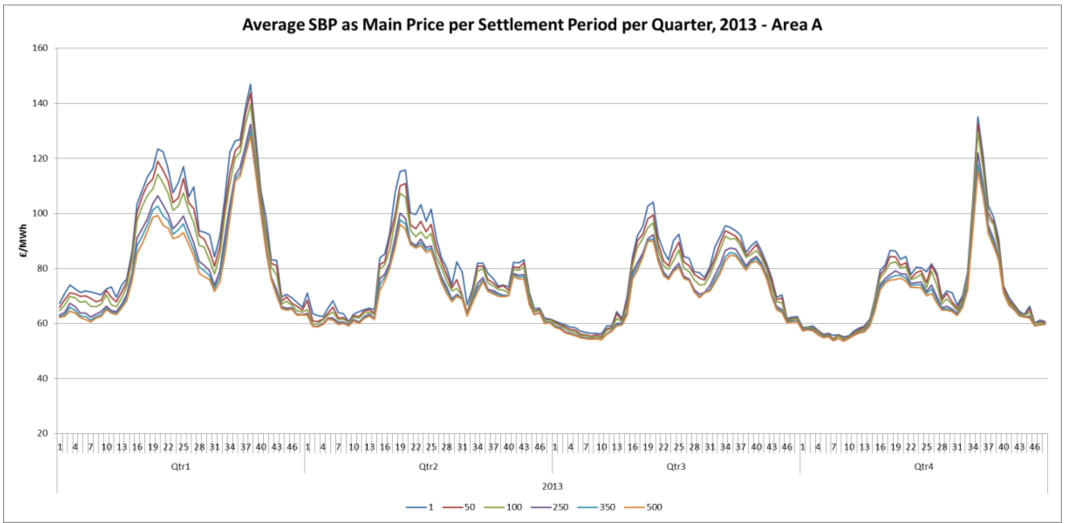


Figure 9

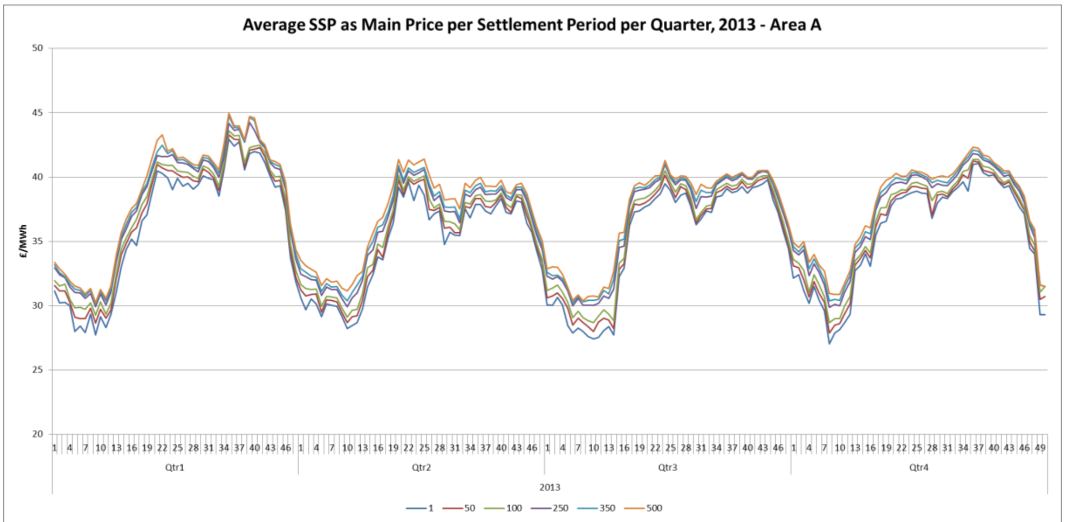


Figure 10

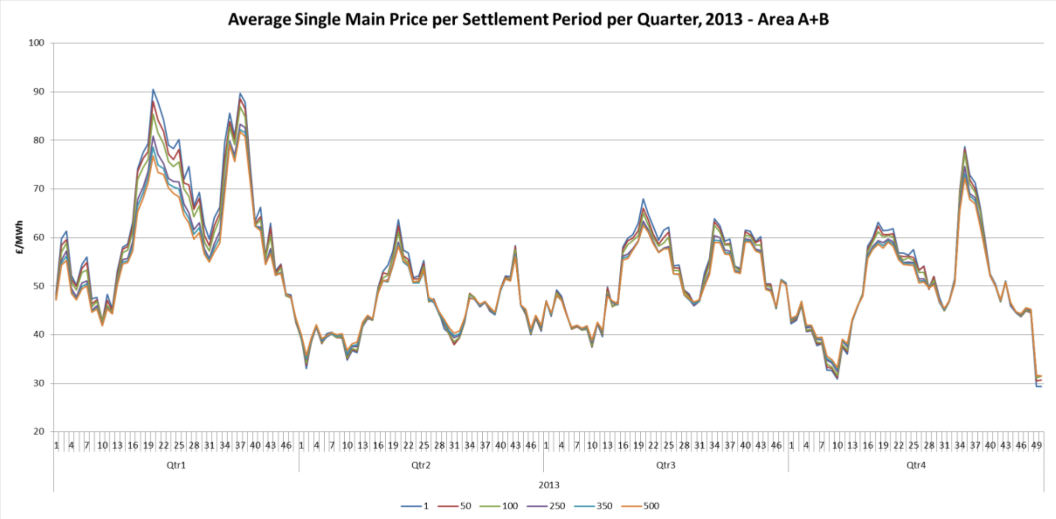
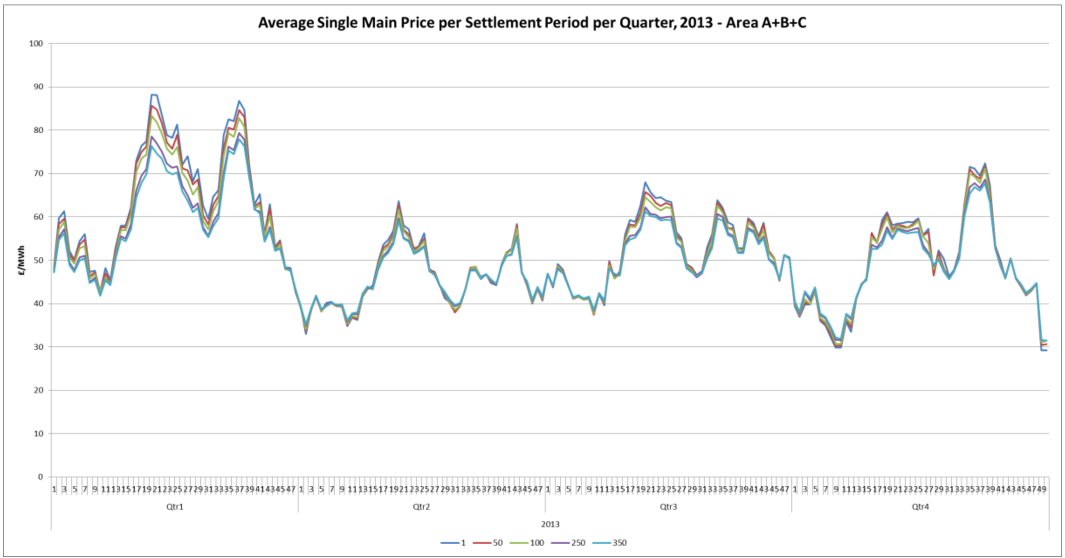


Figure 11



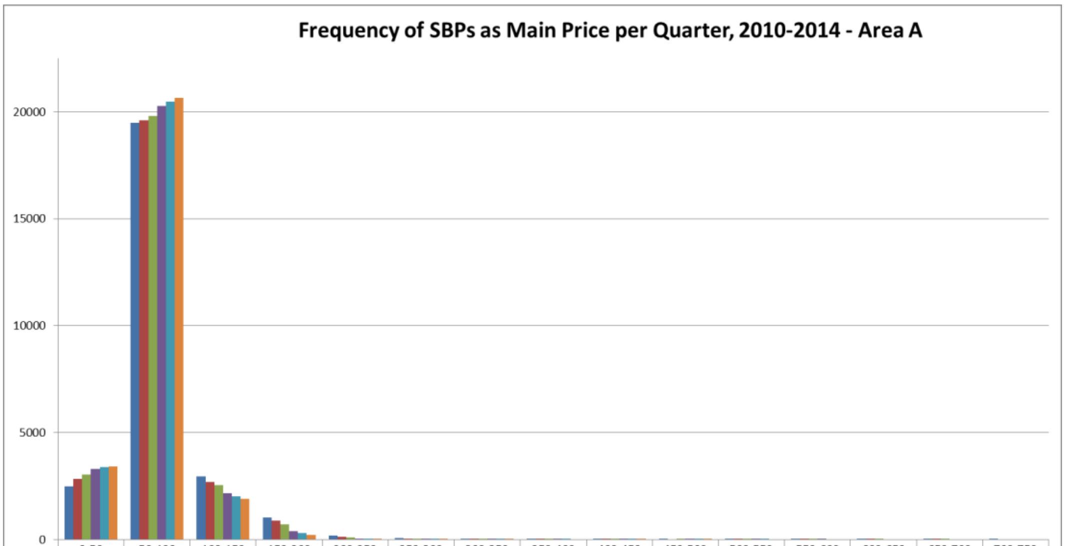
Frequency of prices

Figures 12 to 15 illustrate the frequency of prices calculated under P305 scenarios and further demonstrate the accentuating effect on prices of reducing PAR. Our analysis shows that lower values of PAR produced a wider distribution of prices around the core £0-100/MWh range - which accounts for ~96% of Single Main Prices, ~88% of SSB Main Prices and ~99% of SSP Main Prices.

Assuming PAR 1, there were 4,246 Settlement Periods where the Main Price was between £100/MWh and 750/MWh, almost twice as many than if PAR 500.

Similarly, lower PAR values resulted in an, albeit small number but, greater proportion of larger, negative prices. Between 2010 and 2013, where PAR equalled 500MWh there were 11 instances and where PAR equalled 350MWh there were 17 instances of negative prices, whereas reducing PAR to 1MWh increased the number of instances to 53.

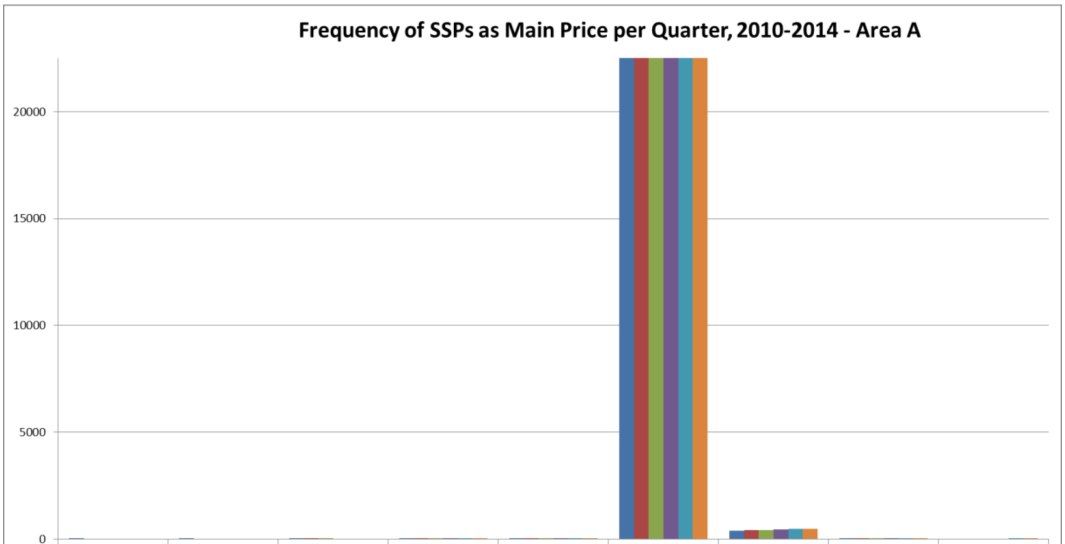
Figure 12



	0-50	50-100	100-150	150-200	200-250	250-300	300-350	350-400	400-450	450-500	500-550	550-600	600-650	650-700	700-750
1	2471	19498	2947	1028	171	63	12	10	2	2	2	3	2	1	1
50	2844	19620	2703	875	125	48	11	6	2		2	3	2	1	
100	3025	19808	2556	698	95	37	12	2	1	1	4	1	1	1	
250	3308	20286	2162	403	50	20	3	2	3	1	3	1			
350	3376	20477	2028	301	35	12	4	4	1	1	3				
500	3425	20648	1903	216	28	10	7		2	3					

£/MWh

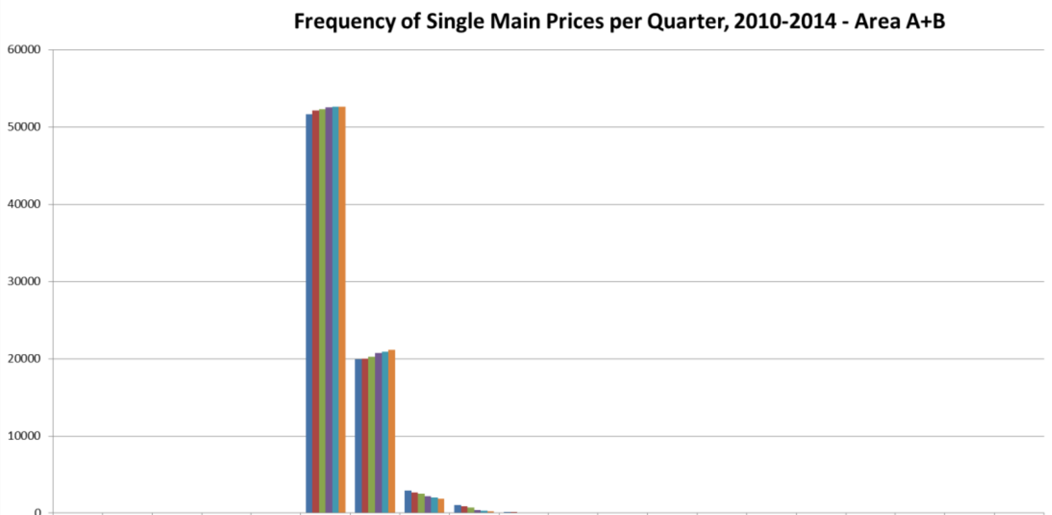
Figure 13



	-250--200	-200--150	-150--100	-100--50	-50-0	0-50	50-100	100-150	150-200
1	1	1	10	22	19	49231	395	2	
50			2	19	25	49276	415	2	
100			1	14	19	49273	431	2	
250				8	12	49257	458	5	
350				1	16	49252	466	4	1
500				1	10	49247	476	4	2

£/MWh

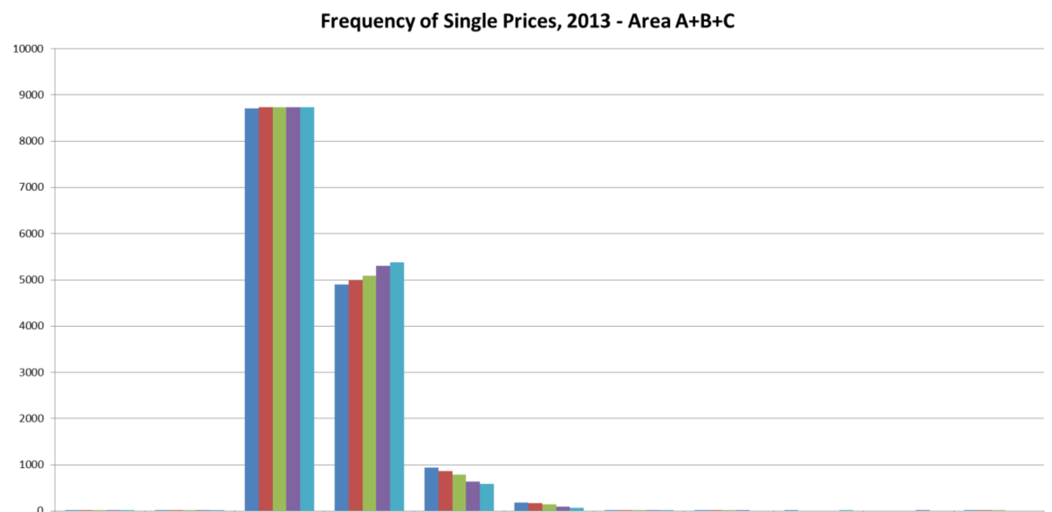
Figure 14



	-250--200	-200--150	-150--100	-100--50	-50-0	0-50	50-100	100-150	150-200	200-250	250-300	300-350	350-400	400-450	450-500	500-550	550-600	600-650	650-700	700-750
1	1	1	10	22	19	51702	19893	2949	1028	171	63	12	10	2	2	2	3	2	1	1
50			2	19	25	52120	20035	2705	875	125	48	11	6	2		2	3	2	1	
100			1	14	19	52298	20239	2558	698	95	37	12	2	1	1	4	1	1	1	
250				8	12	52565	20744	2167	403	50	20	3	2	3	1	3	1			
350				1	16	52628	20943	2032	302	35	12	4	4	1	1	3				
500				1	10	52672	21124	1907	218	28	10	7		2	3					

£/MWh

Figure 15



	-100--50	-50-0	0-50	50-100	100-150	150-200	200-250	250-300	300-350	350-400	450-500
						2013					
1	11	6	8708	4905	940	187	19	3	4		1
50	9	6	8732	4986	862	170	15	3			1
100	7	4	8736	5089	787	146	12	2			1
250	2	6	8734	5301	636	97	6	1		1	
350	1	7	8732	5379	590	69	5		1		

Figure 16

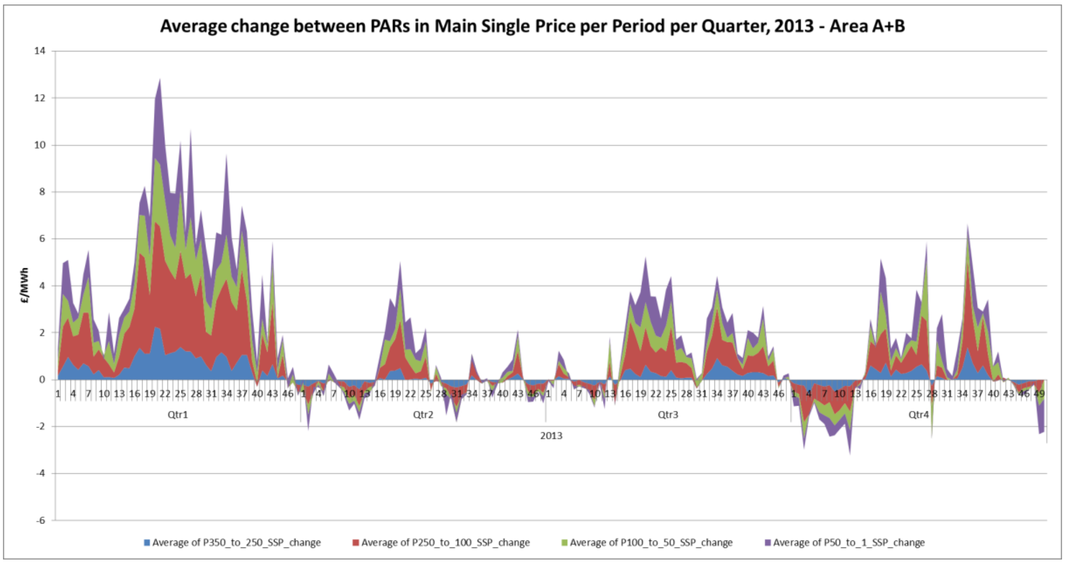


Figure 17

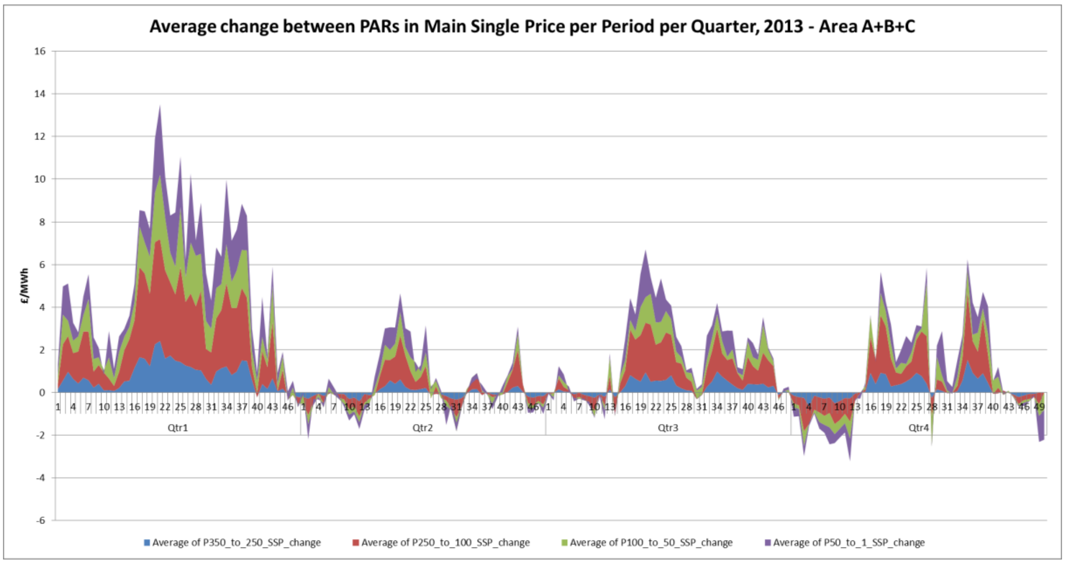


Figure 18

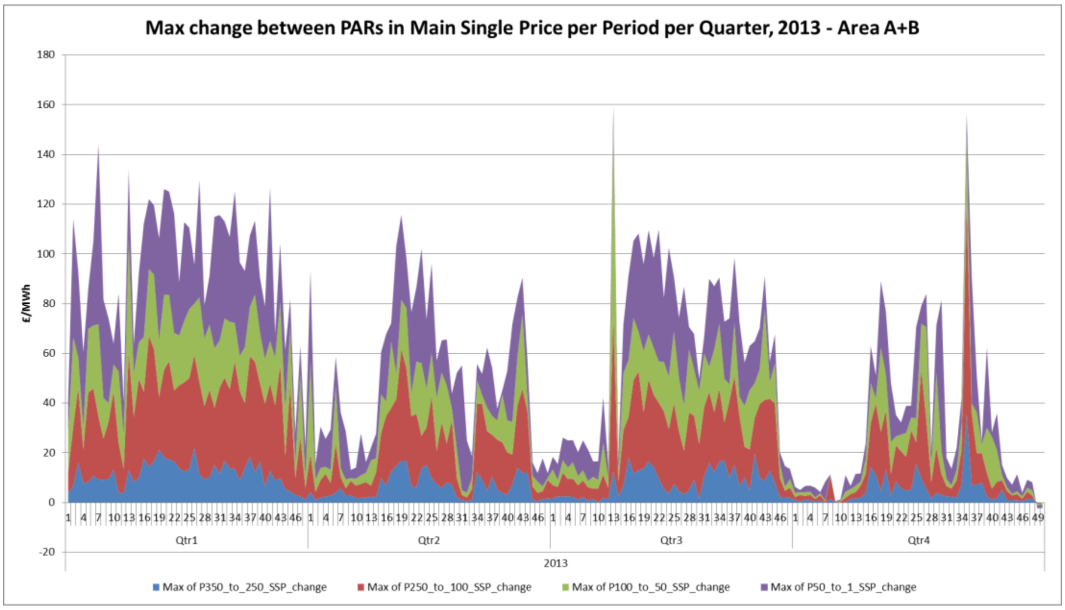
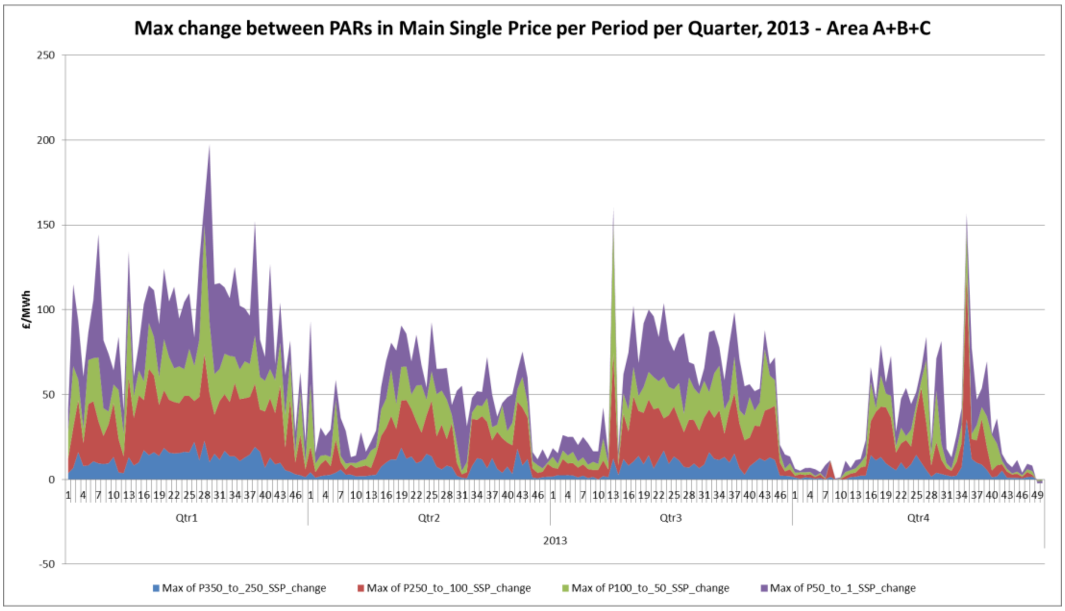


Figure 19



Replacing Dual Prices with a Single Price

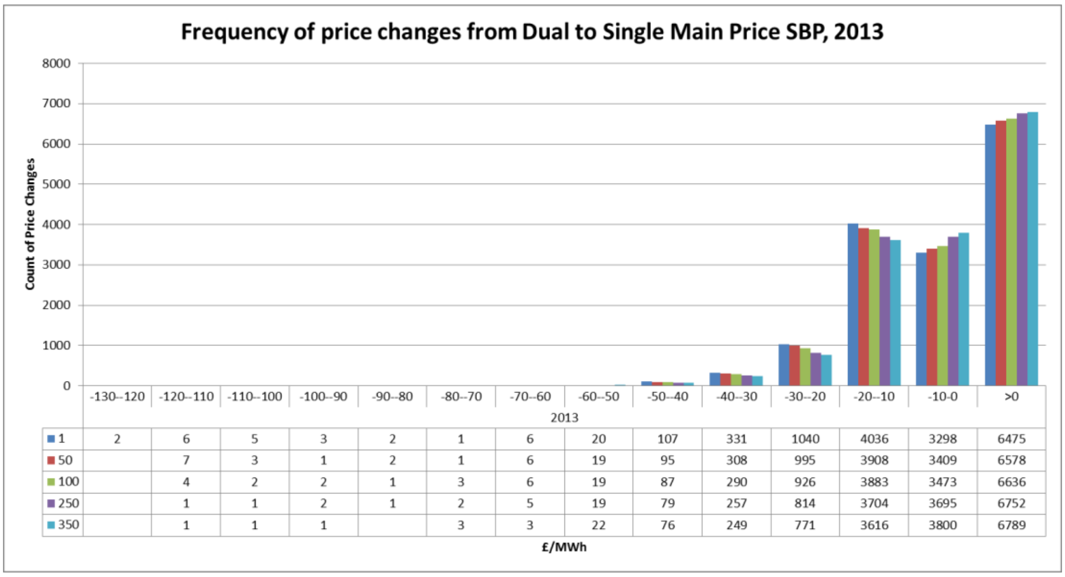
Should P305 be implemented, it would have the effect of setting all Reverse Prices equal to the Main Price. In general this increases SSPs to equal SBP when the system is short and decreases SBPs to equal SSPs when the system is long.

Of 14,784 Settlement Periods analysed in 2013, an average of 38% had the SSP increased to equal SBP and an average of 62% had the SBP reduced to equal SSP.

Between 35.11% (assuming PAR 1) and 39.06% (PAR 350) of affected SSPs increased between £11/MWh and £21/MWh. Whereas 19.41% (PAR 1) and 17.37% (PAR 350) of affected SSPs increased between £21 and £31/MWh. A further 24.36% (PAR 1) and 13.93% (PAR 350) of affected SSPs increased by between £31 and £371/MWh.

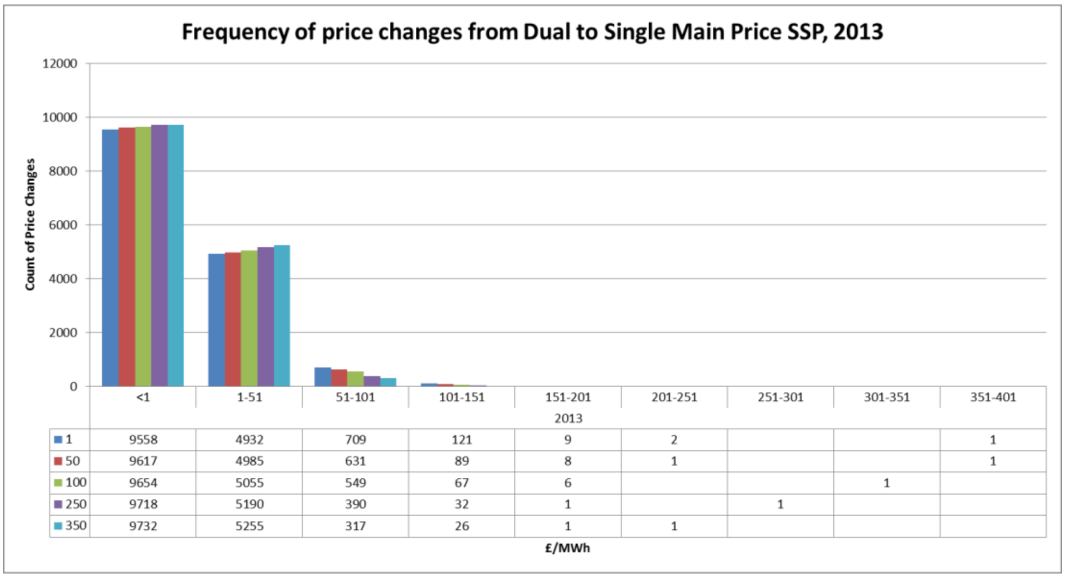
Between 78.98% (PAR 1) and 79.85% (PAR 350) of affected SBPs reduced between £0/MWh and £21/MWh. Whereas 11.03% (PAR 1) and 8.10% (PAR 350) of affected SBPs decreased between £20 and £30/MWh. A further 4.80% (PAR 1) and 3.43% (PAR 350) of affected SBPs decreased by between £30 and £130/MWh.

Figure 20



2013	-130--120	-120--110	-110--100	-100--90	-90--80	-80--70	-70--60	-60--50	-50--40	-40--30	-30--20	-20--10	-10-0	>0
1	2	6	5	3	2	1	6	20	107	331	1040	4036	3298	6475
50		7	3	1	2	1	6	19	95	308	995	3908	3409	6578
100		4	2	2	1	3	6	19	87	290	926	3883	3473	6636
250		1	1	2	1	2	5	19	79	257	814	3704	3695	6752
350		1	1	1		3	3	22	76	249	771	3616	3800	6789

Figure 21



2013	<1	1-51	51-101	101-151	151-201	201-251	251-301	301-351	351-401
1	9558	4932	709	121	9	2			1
50	9617	4985	631	89	8	1			1
100	9654	5055	549	67	6			1	
250	9718	5190	390	32	1		1		
350	9732	5255	317	26	1	1			

Introducing RSP

P305 proposes to initially set the VoLL at £3,000/MWh from November 2015, rising to £6,000/MWh from November 2018. Including the value of Reserve Scarcity to the calculation of imbalance prices in extreme events has the potential to significantly increase imbalance prices. However, whilst our analysis shows that a significant number of Settlement Periods are affected by the inclusion of RS requirements, the typical effect is comparatively limited and in the majority of cases may be contrary to expectation.

As summarised below, the frequency of STOR actions re-priced to RSP in 2013 was very low and the number of instances where a re-priced STOR action did or could have affected the Main Price even lower. Therefore, the impacts of RSP observed in our analysis are likely to be a consequence of additional non-BM STOR actions and revised Buy Price Adjusters in the Main Price calculation, rather than high values of LoLP and RSP influencing the price calculation.

We also observed that in 146 of 14,784 Settlement Periods in 2013, the addition of non-BM STOR actions contributed enough to the volume to switch the system length from long to short.

Frequency of changes

Depending on the value of PAR, of the 14,784 Settlement Periods analysed in 2013, on average 70.93% of Settlement Periods were unaffected by the RSP requirements, 10.10% experienced increased prices and 15.40% experienced reduced prices. Table 2 below shows in more detail the effects of introducing the RSP requirements.

That we observed more decreasing prices than increasing prices may appear contrary to the intent of including RSP in the calculation of imbalance prices. Closer inspection helps to explain the price changes.

In order to assess the exact reason for price changes, the individual Settlement Period calculations would need to be analysed in detail. Due to the short timescales available this deep analysis into many Settlement Periods has not been possible. It is reasonable to predict that on the one hand the RSP requirements have the potential to re-price STOR actions and introduce additional non-BM STOR actions into the price calculation that may increase the average value of all BOAs in the stack, producing higher Main Prices.

However, reducing the PAR value may result in more BOAs, including re-priced or additional STOR actions, being PAR tagged out of the final price calculation.

The larger number of price decreases caused by the inclusion of RSP requirements is likely to be driven by the use of revised BPAs in the Main Price calculation. Revised BPAs are used so the costs of STOR availability charges are removed from the Main Price calculation. The consequence of this is to reduce Main Prices based on SBPs in Settlement Periods where STOR was used. The most notable instance of this caused the highest Main Price calculated in 2013, £520.56/MWh[8], to be reduced by £24.28/MWh.

Table 2

Frequency of price changes driven by introducing RSP requirements

PAR	Prices increased	% increased	Prices unchanged	% unchanged	Prices decreased	% decreased
1	798	5.40%	11,815	79.92%	2,171	14.68%
50	1,246	8.43%	11,245	76.06%	2,293	15.51%
100	1,543	10.44%	10,899	73.72%	2,342	15.84%
250	2,011	13.60%	10,298	69.66%	2,475	16.74%
350	2,141	14.48%	10,121	68.46%	2,522	17.06%

[8] Achieved on 4 November 2013, Settlement Period 35

Figure 22

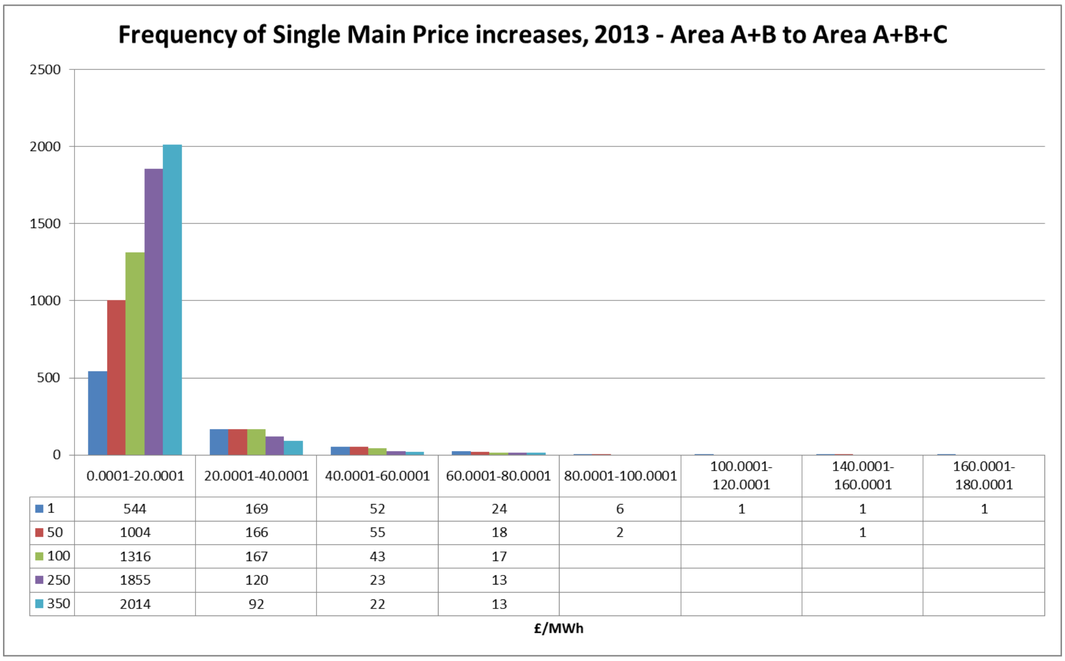
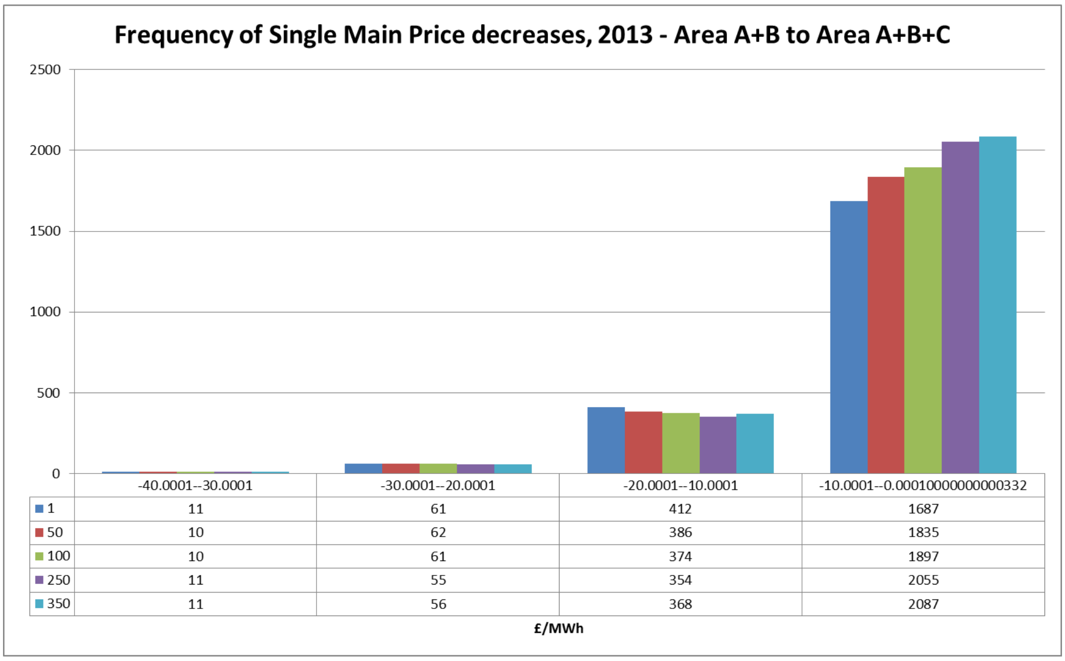


Figure 23



Range of prices driven by RSP

For the 2013 period, the highest and lowest prices calculated under the RSP requirements are summarised in Table 3 below.

Table 3a

Highest Single Main Prices including RSP, 2013 – Area A+B+C					
Settlement Date	Settlement Period	PAR	Single Price exc RSP	Single Price inc RSP	Change in Main Price
04/11/2013	35	50	520.56	496.28	-24.28
04/11/2013	35	1	520.56	496.28	-24.28

Highest Single Main Prices including RSP, 2013 – Area A+B+C					
Settlement Date	Settlement Period	PAR	Single Price exc RSP	Single Price inc RSP	Change in Main Price
04/11/2013	35	100	493.63	469.35	-24.28
04/11/2013	35	250	407.56	383.28	-24.28
04/11/2013	35	350	372.06	347.78	-24.28
04/11/2013	36	1	329.49	311.14	-18.35
24/02/2013	28	1	139.75	300.00	160.25
24/02/2013	29	1	140.00	300.00	160.00
20/03/2013	38	1	192.62	300.00	107.38
24/02/2013	28	50	139.53	293.53	154.00

Table 3b

Lowest Single Main Prices including RSP, 2013 – Area A+B+C					
Settlement Date	Settlement Period	PAR	Single Price exc RSP	Single Price inc RSP	Change in Main Price
31/08/2013	30	50	-78.00	-78.00	0.00
31/08/2013	30	100	-78.00	-78.00	0.00
31/08/2013	31	50	-78.00	-78.00	0.00
31/08/2013	31	100	-78.00	-78.00	0.00
31/08/2013	30	1	-78.00	-78.00	0.00
31/08/2013	31	1	-78.00	-78.00	0.00
06/10/2013	28	1	-78.00	-78.00	0.00
24/10/2013	3	50	-78.00	-78.00	0.00
24/10/2013	4	50	-78.00	-78.00	0.00
24/10/2013	4	100	-78.00	-78.00	0.00

Table 3c

Largest increase in Single Main Prices including RSP, 2013 – Area A+B+C					
Settlement Date	Settlement Period	PAR	Single Price exc RSP	Single Price inc RSP	Change in Main Price
24/02/2013	28	1	139.75	300.00	160.25
24/02/2013	29	1	140.00	300.00	160.00
24/02/2013	28	50	139.53	293.53	154.00
20/03/2013	38	1	192.62	300.00	107.38
26/02/2013	*36*	*1*	*46.05*	*140.00*	*93.95*
11/01/2013	*18*	*1*	*40.90*	*125.00*	*84.10*
29/06/2013	*18*	*1*	*36.70*	*120.00*	*83.30*

Largest increase in Single Main Prices including RSP, 2013 – Area A+B+C					
Settlement Date	Settlement Period	PAR	Single Price exc RSP	Single Price inc RSP	Change in Main Price
28/07/2013	*44*	*1*	*38.29*	*120.00*	*81.71*
28/07/2013	*43*	*1*	*38.30*	*120.00*	*81.70*
28/07/2013	*44*	*50*	*38.29*	*119.87*	*81.57*
24/02/2013	*28*	*1*	*139.75*	*300.00*	*160.25*
24/02/2013	*29*	*1*	*140.00*	*300.00*	*160.00*

Italicised text identifies Settlement Periods where the NIV switched as a consequence of including RSP requirements in Main Price calculation. Consequently the System Length changed from Long to Short.

Figure 24

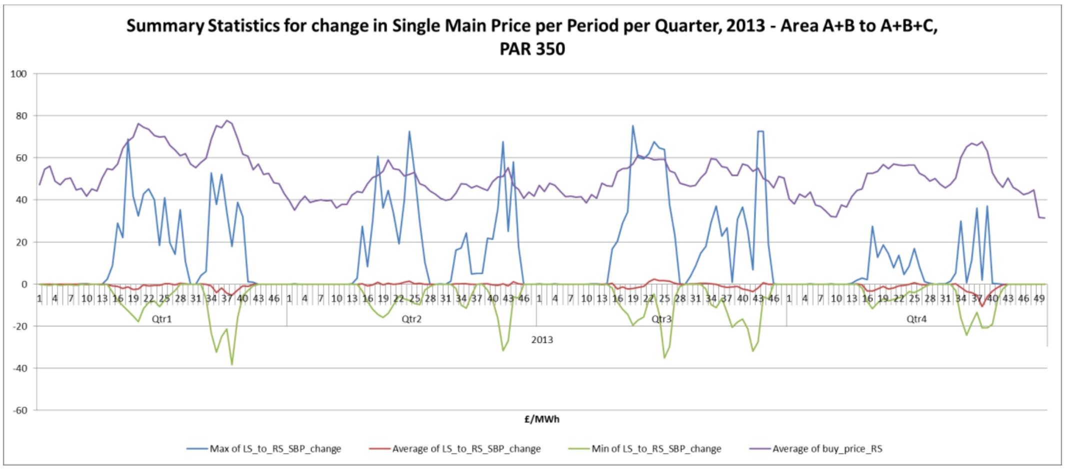
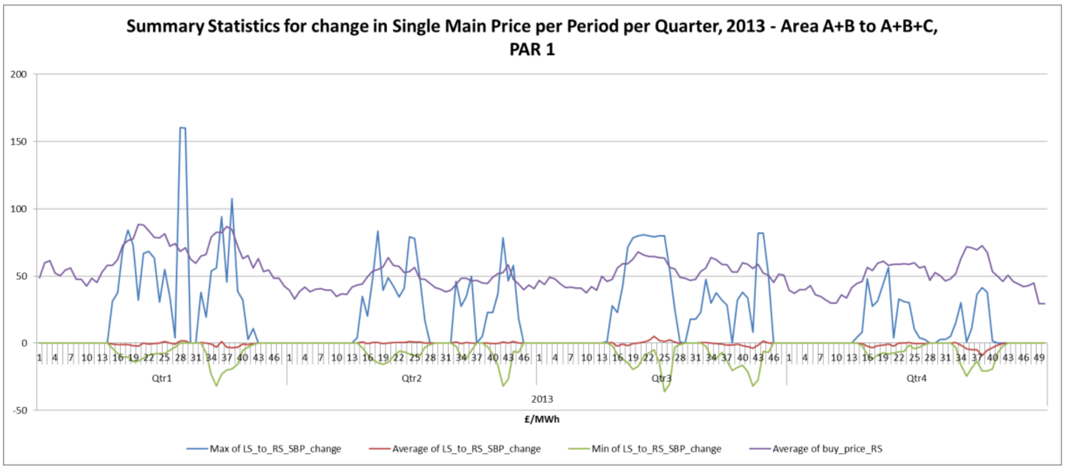


Figure 25



Frequency of re-pricing STOR actions

Figures 22 and 23 illustrate the number and frequency of STOR actions taken during 2013 and the number of those actions that had their utilisation prices re-priced to equal RSP.

Of 38,225 STOR actions in 2013, 36 actions would have been re-priced at RSP where VoLL was equal to £3,000/MWh and 46 actions would have been re-priced at RSP where VoLL was equal to £6,000/MWh.

Figure 26

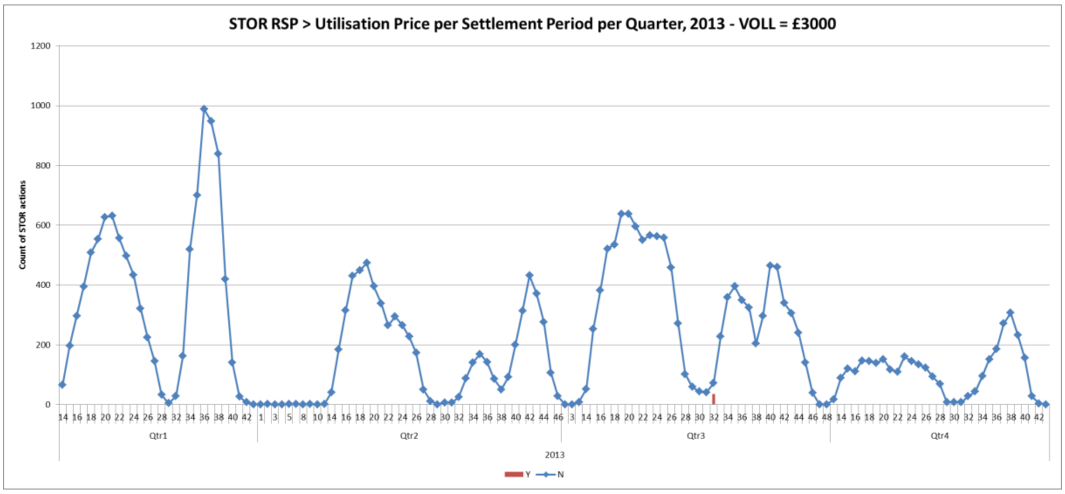
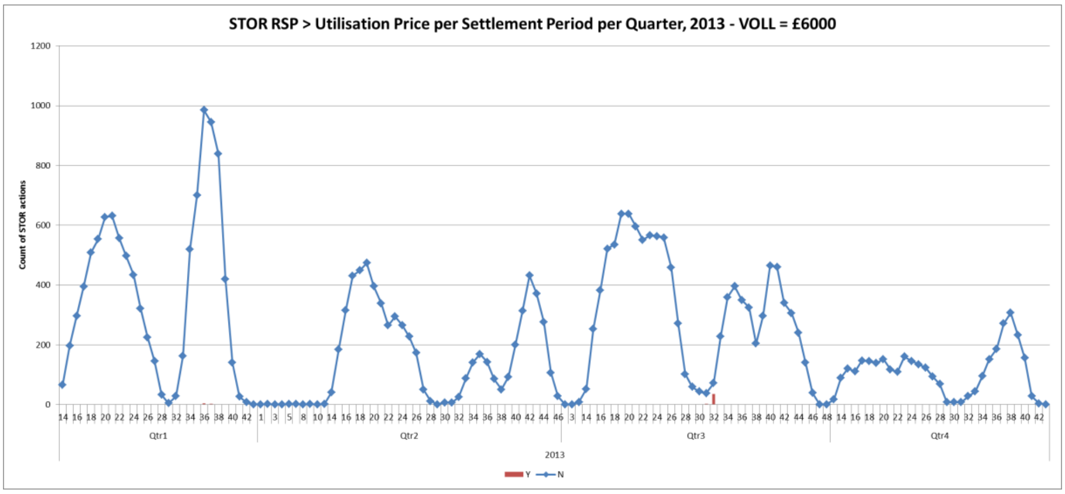


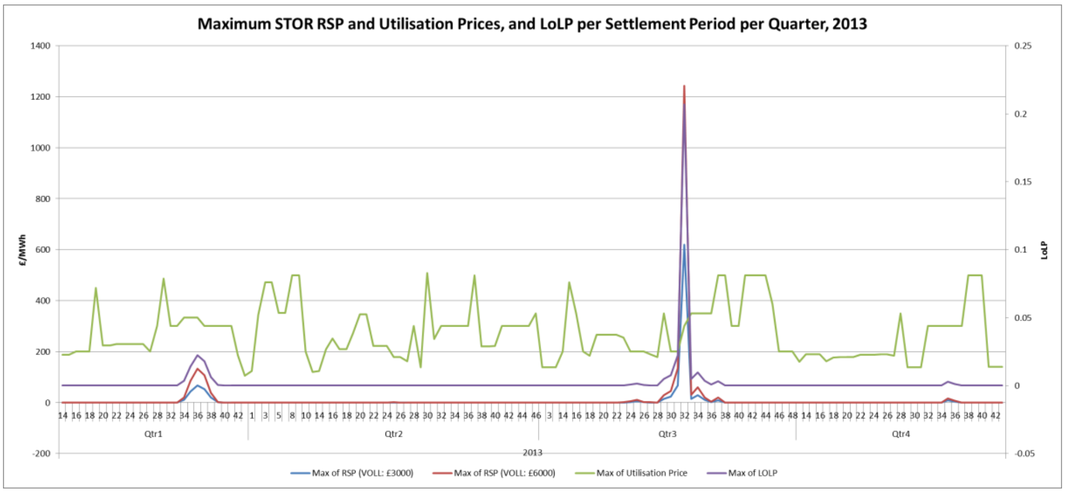
Figure 27



In those instances where STOR actions are priced at RSP and VoLL equalled £3,000/MWh, all 36 actions would have either been tagged out of the calculation by the DMAT or by NIV tagging.

Whilst our analysis did not calculate prices where VoLL equalled £6,000/MWh, a simple review of the Bids and Offers during periods where STOR actions were re-priced to RSP suggests that at most 10 of the 46 re-priced actions may have contributed to the final Main Price.

Figure 28



Impacts on Parties

This subsection focuses on providing a summary of how the P305 requirements could have impacted BSC Parties' historical trading charges. In particular, using the imbalance prices calculated using the P305 scenarios described above, our model has recalculated the absolute differences in BSC Parties' imbalance charges, RCRC charges and overall net positions[9], and calculated each Parties' change in net position divided by its credited energy volume to produce a comparable £/MWh. In this sense our analysis simply recalculates the impacts of prices on existing, historical imbalance positions. It does not take account of any change in Parties' behaviours in terms of managing their imbalance positions as a consequence of changes to incentives intended by P305.

In general, reducing PAR and the introduction of a single price approach appear to be the most influential elements of P305 on Parties' imbalance charges and overall net positions. As demonstrated above, reducing PAR typically has the effect of increasing SBPs and reducing SSPs, which could have a more detrimental effect on parties who fail to manage their imbalance positions adequately. The introduction of a Single Price approach that tends not to use a Market Price has the effect of increasing the spread between SBPs and SSPs that a Party may be charged at from one Settlement Period to the next. This spread is accentuated by higher SBPs and lower SSPs driven by lower PAR values.

The effects of P305 scenarios are summarised in Tables 4 to 12 further below. Each table provides an aggregated Quarterly view of changes to charges for different BSC Party types – independent suppliers, independent thermal generators, independent wind generators, vertically integrated parties, interconnectors and a 'null' category that reflects all other uncategorised Parties.[10]

Impacts on Parties' imbalance cash flows

Tables 4, 5 and 6 summarise the total change on Parties' imbalance cash flows caused by P305 scenarios. A positive value of 'imbalance_cash_flow_delta' represents an increase in the imbalance charges paid by a Party. A negative value represents a reduction in charges paid.

[9] A Party's Net Position is the sum of its change in Imbalance Charge and change in RCRC

[10] The Party Types reflect the same types used for our P304 analysis, which were originally compiled to support analysis for Ofgem's EBSCR analysis. The categorisation of parties was based on those Parties' consent. Consequently not all Parties' were categorised and are therefore captured by our 'null' category.

Under dual price arrangements all party types' imbalance cash flows are typically worse on average in all quarters. Parties' imbalance cash flow worsens in all quarters progressively and consistently as PAR is reduced. As described in our analysis of reducing PAR on prices above, deteriorating imbalance cash flows are likely to be driven by an increasing spread between SBPs and SSPs with Market Prices caused by reducing PAR values.

By introducing Single Price arrangements, P305 could have the effect of reducing all party types' imbalance cash flows. This may be a consequence of generally reducing ~60% of Settlement Periods SBPs to the SSP, which would have the effect of reducing the amount paid to parties that are long or payments by parties that are short in these periods. However, reducing PAR has the effect of generally widening the gap between average SBPs and SSPs. This may explain why any beneficial reduction in imbalance cash flows due to a single price is consistently eroded as PAR reduces.

Impacts on Parties' RCRC receipts

Tables 7, 8 and 9 summarise the absolute impacts of P305 scenarios on Parties' RCRC receipts. A positive value of 'RCRC_delta' represents an increase in RCRC charges or a decrease in RCRC payments to Parties. Whereas a negative value of 'RCRC_delta' represents a decrease in RCRC charges or an increase in RCRC payments.

All monies recovered or paid through imbalance charges are returned back to or paid by Parties through RCRC in proportion to a parties credited energy volume(s). Consequently any increase or decrease in imbalance charge cash flow will have a direct impact on the size of RCRC payments made by or paid back to BSC Parties.

As described above, because imbalance cash flows increased under dual price arrangements, the volumes of RCRC received by all Parties increased too.

Conversely, under single price arrangements, imbalance cash flows reduced and so the size of RCRC charges and receipts to all parties reduced too.

Impacts on Parties' net positions

Each Parties' net position is the sum of imbalance cashflows and RCRC. A positive net position represents an increase in charges paid by a Party, whereas a negative value represents a decrease in the charges paid by a Party.

Under dual price arrangements, Independent Suppliers and Interconnectors consistently pay more under P305 scenarios. This is because they pay more imbalance charges than they receive in terms of RCRC receipts. This position is made worse by reducing PAR.

On the other hand Vertically Integrated parties and Independent Thermal generators typically benefit under dual price arrangements as they receive a greater proportion of RCRC payments which counteract increases in imbalance cashflows.

By moving to single price arrangements all parties except Vertically Integrated parties benefit. This is primarily because as net beneficiaries or contributors of RCRC, Vertically Integrated parties are affected most by receiving a decreasing amount through RCRC as the level of imbalance cashflow decreases.

Table 4 – Total impacts of P305 scenarios on Imbalance Cashflows (£s) – Area A

Sum of imbalance_cashflow_delta	Column Labels																
	Live																
	Twin																
	2010				2011				2012				2013				2014	
Row Labels	1	2	3	4	1	2	3	4	1	2	3	4	1	2	3	4	1	2
1																		
Independent Supplier	437,707	669,287	471,979	1,767,501	927,459	843,562	1,043,425	1,003,779	1,189,823	1,314,978	956,401	1,512,957	2,446,168	1,262,276	1,161,163	1,390,132	1,416,799	1,081,257
Independent Thermal	596,138	1,527,641	936,537	3,290,828	1,244,818	924,459	2,454,257	1,245,244	1,810,082	1,544,797	1,165,637	1,617,662	2,317,584	1,000,314	1,164,821	1,166,824	1,134,874	696,866
Independent Wind	0	2	0	12	3	3	13	9	10	8	13	31	4,281	52	42,199	43	45	19
Interconnector	24,065	25,350	9,647	46,129	70,832	35,204	150,666	83,486	94,208	99,826	78,405	102,951	104,008	73,555	76,051	50,885	68,074	17,656
NULL	0	0	0	0	0	0	0	0	0	0	0	0	2,551	34	2,061	61,682	115,624	44,282
Vertically Integrated	6,145,224	7,780,649	5,025,985	20,716,772	9,552,137	6,378,323	9,039,185	7,997,442	12,977,932	11,142,300	6,447,031	12,224,792	20,163,389	8,635,890	7,540,131	8,797,106	9,528,350	6,016,036
50																		
Independent Supplier	318,184	487,029	390,987	1,365,686	698,696	681,791	778,965	748,039	968,447	968,639	739,697	1,201,963	1,943,223	981,000	910,989	1,132,155	1,155,165	794,148
Independent Thermal	417,073	1,168,933	743,968	2,641,123	936,770	744,064	1,818,640	972,222	1,500,877	1,141,851	902,100	1,291,994	1,831,747	775,178	911,624	918,496	949,023	534,358
Independent Wind	0	2	0	9	2	3	9	7	8	5	10	24	3,525	41	32,855	34	35	14
Interconnector	18,195	16,608	7,698	33,167	58,275	27,572	84,665	69,377	75,757	73,586	61,318	78,731	79,911	53,700	54,790	40,596	56,180	14,096
NULL	0	0	0	0	0	0	0	0	0	0	0	0	2,543	88	1,203	46,553	88,813	34,168
Vertically Integrated	4,516,482	5,954,159	4,063,977	16,368,075	7,491,564	5,307,227	6,647,531	6,165,910	10,664,978	8,470,244	5,067,616	9,832,396	16,143,143	6,739,688	6,008,769	7,187,010	7,808,297	4,273,040
100																		
Independent Supplier	236,952	353,868	321,329	1,079,755	524,168	544,911	595,086	556,892	774,505	743,058	557,716	933,440	1,495,974	771,193	690,277	886,930	913,340	590,090
Independent Thermal	310,044	870,211	604,296	2,099,494	709,207	582,537	1,360,976	741,412	1,226,735	874,342	685,026	1,007,137	1,409,973	596,453	691,215	715,093	754,510	403,896
Independent Wind	0	1	0	7	2	2	7	5	6	4	7	19	2,648	33	26,256	27	28	11
Interconnector	14,431	10,994	5,953	25,356	43,416	21,693	55,247	53,021	56,940	54,663	41,940	62,543	57,804	39,428	35,376	30,641	45,509	11,171
NULL	0	0	0	0	0	0	0	0	0	0	0	0	1,374	69	914	35,158	71,559	26,238
Vertically Integrated	3,383,335	4,502,025	3,343,448	13,198,113	5,778,885	4,302,986	5,099,256	4,753,658	8,601,089	6,535,750	3,919,712	7,666,741	12,476,048	5,253,563	4,567,995	5,697,181	6,238,757	3,164,513
250																		
Independent Supplier	89,460	120,688	168,642	489,029	209,621	255,862	235,285	223,748	350,038	326,498	216,760	412,810	637,555	380,574	261,747	392,513	430,372	254,613
Independent Thermal	125,875	321,586	304,531	983,677	275,394	262,152	531,895	297,890	582,386	375,562	282,524	468,885	601,406	285,229	266,214	328,368	348,712	174,567
Independent Wind	0	0	0	3	1	1	2	2	3	1	3	8	945	18	10,640	12	14	5
Interconnector	6,705	3,724	2,326	10,918	14,672	9,838	21,180	22,154	19,904	22,138	12,043	29,683	22,537	17,665	10,719	11,803	18,120	5,372
NULL	0	0	0	0	0	0	0	0	0	0	0	0	459	25	256	15,787	37,017	10,011
Vertically Integrated	1,352,878	1,822,691	1,767,140	6,120,283	2,443,780	2,113,480	2,087,501	2,071,565	4,031,250	2,950,613	1,591,959	3,391,868	5,311,649	2,572,474	1,815,577	2,616,773	3,013,618	1,358,769
350																		
Independent Supplier	40,514	53,627	99,384	246,368	98,144	137,203	108,686	103,710	178,365	156,051	96,794	205,471	312,218	220,891	119,839	197,065	231,514	121,545
Independent Thermal	63,791	140,067	176,401	504,613	123,997	140,564	250,386	129,782	291,978	171,417	129,824	240,633	296,243	159,874	116,183	170,098	178,339	83,092
Independent Wind	0	0	0	2	0	1	1	1	1	1	1	4	442	11	4,810	7	9	2
Interconnector	3,152	1,708	1,126	5,273	8,035	5,186	9,920	9,880	9,585	10,084	4,757	15,602	10,507	9,594	4,203	5,432	8,387	2,459
NULL	0	0	0	0	0	0	0	0	0	0	0	0	197	15	68	8,136	21,788	4,670
Vertically Integrated	632,727	866,130	1,054,257	3,113,008	1,182,309	1,163,425	978,787	1,014,649	2,070,724	1,438,844	734,894	1,678,860	2,584,815	1,485,173	834,023	1,313,792	1,571,407	630,583

Table 5 - Total impacts of P305 scenarios on Imbalance Cashflows (£s) – Area A+B

Sum of imbalance_cashflow_delta	Column Labels Live Single 2010				2011				2012				2013				2014	
Row Labels	1	2	3	4	1	2	3	4	1	2	3	4	1	2	3	4	1	2
1																		
Independent Supplier	-489,403	-1,032,978	-917,333	-3,904,578	-2,166,133	-1,702,310	-2,127,278	-1,570,115	-1,485,631	-1,826,926	-1,586,601	-2,459,853	-4,044,880	-1,558,386	-2,804,219	-3,467,597	-2,229,666	-1,095,598
Independent Thermal	-1,161,500	-1,880,589	-1,777,630	-3,220,566	-2,149,681	-1,615,700	-1,416,373	-2,215,773	-2,718,884	-3,618,344	-2,139,369	-2,727,538	-3,821,234	-1,737,890	-2,316,425	-2,340,485	-1,614,078	-1,054,829
Independent Wind	0	-60	0	5	-15	-9	-25	-41	-74	-80	-62	-129	-1,327	-109	-168,292	-214	-228	-102
Interconnector	-89,170	-69,301	-70,214	-187,293	-121,537	-160,840	-124,598	-251,045	-270,458	-112,862	-221,271	-208,603	-167,643	-166,301	-164,587	-158,800	-108,905	-45,107
NULL	0	0	0	0	0	0	0	0	0	0	0	0	91	-2,477	-6,438	-332,430	-313,305	-112,739
Vertically Integrated	-375,328	-2,807,389	-3,977,622	2,715,733	-1,660,395	-3,397,038	-1,685,250	-4,474,713	-1,362,648	-3,079,317	-4,150,349	-5,900,207	-3,453,680	-5,476,318	-4,936,845	-6,380,026	-2,809,873	-2,329,008
50																		
Independent Supplier	-539,393	-1,094,730	-938,779	-3,799,737	-2,194,356	-1,727,403	-2,097,255	-1,674,823	-1,573,105	-1,973,374	-1,674,151	-2,550,602	-4,083,548	-1,651,681	-2,821,498	-3,496,559	-2,288,707	-1,199,854
Independent Thermal	-1,193,625	-1,990,040	-1,855,661	-3,322,307	-2,226,689	-1,668,991	-1,761,533	-2,291,879	-2,756,197	-3,652,450	-2,211,823	-2,807,313	-3,856,944	-1,787,257	-2,393,140	-2,418,523	-1,641,028	-1,060,230
Independent Wind	0	-57	0	2	-14	-9	-26	-41	-71	-76	-60	-125	-1,597	-108	-169,569	-209	-221	-97
Interconnector	-87,978	-71,698	-68,247	-178,200	-124,592	-161,557	-166,958	-246,643	-272,417	-128,164	-221,742	-219,810	-177,045	-175,090	-177,639	-161,817	-112,895	-44,526
NULL	0	0	0	0	0	0	0	0	0	0	0	0	83	-2,179	-7,076	-325,984	-317,160	-107,627
Vertically Integrated	-1,468,843	-3,891,564	-4,587,919	-314,651	-2,984,951	-4,009,175	-3,194,339	-5,549,879	-2,963,211	-4,779,066	-4,958,407	-7,307,775	-5,847,602	-6,520,815	-5,791,071	-7,315,624	-3,868,779	-3,082,588
100																		
Independent Supplier	-574,450	-1,139,903	-966,374	-3,720,722	-2,197,590	-1,757,969	-2,097,047	-1,753,787	-1,652,246	-2,056,481	-1,754,586	-2,637,495	-4,122,961	-1,733,327	-2,857,464	-3,560,758	-2,346,121	-1,267,391
Independent Thermal	-1,193,059	-2,091,171	-1,900,970	-3,466,603	-2,277,972	-1,724,170	-2,015,175	-2,373,698	-2,797,786	-3,656,843	-2,284,992	-2,876,619	-3,877,816	-1,845,705	-2,454,032	-2,479,667	-1,692,347	-1,079,980
Independent Wind	0	-51	0	0	-14	-9	-26	-40	-68	-73	-59	-123	-2,218	-108	-166,290	-205	-214	-92
Interconnector	-85,211	-72,467	-67,078	-172,677	-130,934	-160,476	-178,536	-249,742	-275,559	-141,622	-229,316	-225,119	-186,517	-180,666	-189,819	-165,185	-117,373	-43,877
NULL	0	0	0	0	0	0	0	0	0	0	0	0	-1,073	-2,093	-7,147	-317,059	-312,282	-106,076
Vertically Integrated	-2,266,560	-4,815,804	-5,039,866	-2,537,066	-4,164,461	-4,655,808	-4,146,388	-6,432,111	-4,448,382	-6,052,992	-5,681,860	-8,656,884	-8,153,748	-7,411,177	-6,704,998	-8,251,386	-4,885,272	-3,704,076
250																		
Independent Supplier	-634,639	-1,227,759	-1,029,387	-3,565,418	-2,194,248	-1,871,522	-2,152,656	-1,891,655	-1,823,457	-2,238,871	-1,914,724	-2,832,610	-4,229,667	-1,917,997	-2,982,315	-3,709,274	-2,488,462	-1,379,074
Independent Thermal	-1,185,252	-2,318,828	-2,032,311	-3,767,039	-2,375,844	-1,862,901	-2,494,945	-2,537,588	-2,970,855	-3,708,000	-2,452,764	-2,994,942	-3,969,014	-1,954,333	-2,617,842	-2,589,337	-1,828,782	-1,123,124
Independent Wind	0	-45	-1	-4	-13	-9	-27	-39	-62	-67	-57	-118	-3,277	-109	-160,935	-198	-200	-83
Interconnector	-80,632	-69,571	-65,693	-164,216	-145,032	-159,542	-185,928	-253,383	-278,532	-160,753	-240,706	-233,433	-196,130	-185,659	-200,941	-171,278	-131,885	-43,970
NULL	0	0	0	0	0	0	0	0	0	0	0	0	-1,971	-2,096	-7,412	-301,199	-304,307	-106,818
Vertically Integrated	-3,738,189	-6,665,453	-6,114,242	-7,826,577	-6,591,643	-6,240,459	-6,203,598	-8,252,445	-7,907,346	-8,622,251	-7,295,492	-11,555,222	-12,979,093	-9,181,752	-8,592,627	-10,319,573	-7,135,423	-4,922,654
350																		
Independent Supplier	-654,199	-1,251,331	-1,066,617	-3,516,981	-2,197,510	-1,924,210	-2,193,017	-1,941,730	-1,898,933	-2,328,372	-1,979,891	-2,929,282	-4,298,712	-2,010,415	-3,030,328	-3,770,949	-2,559,512	-1,428,117
Independent Thermal	-1,191,656	-2,411,613	-2,101,863	-3,938,941	-2,419,489	-1,920,889	-2,667,926	-2,605,606	-3,088,501	-3,747,228	-2,536,254	-3,066,682	-4,030,269	-2,010,874	-2,693,454	-2,645,337	-1,894,733	-1,139,937
Independent Wind	0	-41	-1	-5	-13	-9	-27	-38	-60	-65	-56	-116	-3,429	-111	-159,660	-196	-195	-81
Interconnector	-80,352	-68,654	-64,796	-162,539	-146,011	-159,128	-188,109	-252,778	-274,857	-168,523	-241,845	-236,041	-199,655	-187,134	-203,211	-172,880	-136,583	-44,781
NULL	0	0	0	0	0	0	0	0	0	0	0	0	-2,218	-2,099	-7,489	-296,896	-304,549	-107,253
Vertically Integrated	-4,300,158	-7,411,384	-6,660,304	-10,219,393	-7,592,715	-6,991,132	-7,035,214	-9,044,299	-9,480,298	-9,791,731	-7,952,007	-12,820,304	-14,973,449	-9,966,965	-9,351,038	-11,249,031	-8,233,481	-5,482,448

Table 6 - Total impacts of P305 scenarios on Imbalance Cashflows (£s) – Area A+B+C

Sum of imbalance_cashflow_delta	Column Labels			
	RSP			
	Single			
	2013			
Row Labels	**1**	**2**	**3**	**4**
1				
Independent Supplier	-4,126,508	-1,752,150	-3,089,811	-1,036,818
Independent Thermal	-3,794,652	-1,750,753	-2,206,277	-919,039
Independent Wind	-2,166	-113	-177,266	-73
Interconnector	-171,381	-167,567	-165,691	-52,038
NULL	-807	-2,514	-6,705	-122,811
Vertically Integrated	-4,216,416	-5,547,774	-5,624,471	-2,242,025
50				
Independent Supplier	-4,171,388	-1,840,336	-3,103,053	-1,044,102
Independent Thermal	-3,813,691	-1,804,261	-2,254,496	-935,685
Independent Wind	-2,145	-112	-177,065	-72
Interconnector	-180,840	-171,680	-178,750	-52,613
NULL	-806	-2,216	-7,308	-119,487
Vertically Integrated	-6,687,390	-6,499,303	-6,462,856	-2,637,310
100				
Independent Supplier	-4,199,205	-1,907,510	-3,126,549	-1,068,128
Independent Thermal	-3,815,927	-1,855,364	-2,324,571	-954,160
Independent Wind	-2,596	-110	-171,178	-70
Interconnector	-191,861	-178,596	-187,964	-54,133
NULL	-1,475	-2,130	-7,355	-113,831
Vertically Integrated	-8,981,582	-7,384,936	-7,296,601	-3,035,304
250				
Independent Supplier	-4,294,903	-2,062,591	-3,212,740	-1,106,165
Independent Thermal	-3,878,761	-1,948,108	-2,518,340	-990,992
Independent Wind	-3,483	-110	-161,947	-67
Interconnector	-202,602	-185,216	-208,001	-57,195
NULL	-2,548	-2,133	-7,674	-104,966
Vertically Integrated	-13,854,575	-9,205,305	-9,301,564	-3,978,811
350				
Independent Supplier	-4,335,372	-2,148,211	-3,243,808	-1,120,960
Independent Thermal	-3,928,870	-2,006,948	-2,601,378	-1,006,110
Independent Wind	-3,600	-112	-160,443	-66
Interconnector	-207,555	-186,843	-211,397	-57,939
NULL	-2,741	-2,136	-7,786	-102,664
Vertically Integrated	-15,981,477	-10,033,069	-10,138,829	-4,414,671

Table 7 - Total impacts of P305 scenarios on RCRC (£s) – Area A

Sum of rcrc_delta	Column Labels Live Twin																	
	2010				2011				2012				2013				2014	
Row Labels	1	2	3	4	1	2	3	4	1	2	3	4	1	2	3	4	1	2
1																		
Independent Supplier	-100,497	-178,994	-141,233	-490,789	-223,930	-169,510	-308,953	-244,912	-413,870	-377,842	-339,484	-572,227	-1,098,379	-619,895	-391,659	-464,916	-489,301	-364,615
Independent Thermal	-1,158,662	-1,784,587	-1,221,462	-3,820,162	-1,831,373	-1,389,561	-2,184,644	-1,663,307	-2,505,669	-2,165,526	-1,301,937	-2,195,578	-3,391,739	-1,581,465	-1,580,662	-1,760,791	-1,749,518	-1,100,788
Independent Wind	0	0	0	0	0	-4	8	-141	-6	-3	61	425	-148	501	-2,596	3,889	3,471	438
Interconnector	-915	-932	-530	-2,165	-6,721	-34,753	-52,317	-35,229	-69,218	-67,862	-44,386	-70,185	-110,845	-59,684	0	0	0	0
NULL	0	0	0	0	0	0	0	0	0	0	0	0	0	-1	-16	-9,699	-10,357	-6,594
Vertically Integrated	-5,943,060	-8,038,415	-5,080,923	-21,508,125	-9,733,224	-6,587,723	-10,141,638	-8,386,370	-13,083,291	-11,490,675	-6,961,739	-12,620,827	-20,436,868	-8,711,578	-8,011,492	-9,235,155	-10,018,059	-6,384,557
50																		
Independent Supplier	-73,055	-137,419	-114,525	-385,010	-173,104	-139,908	-228,535	-188,591	-341,065	-284,583	-265,744	-458,404	-875,030	-484,780	-310,860	-378,181	-399,231	-261,091
Independent Thermal	-844,454	-1,364,154	-986,477	-3,017,720	-1,424,526	-1,151,441	-1,609,878	-1,281,802	-2,057,237	-1,634,662	-1,018,467	-1,762,318	-2,709,571	-1,234,520	-1,251,967	-1,431,768	-1,432,132	-787,946
Independent Wind	0	0	0	0	0	-2	3	-141	-6	-2	54	387	-131	201	-2,271	3,155	3,062	380
Interconnector	-730	-676	-424	-1,583	-5,657	-29,397	-39,574	-27,018	-56,515	-51,291	-34,635	-55,976	-88,081	-46,716	0	0	0	0
NULL	0	0	0	0	0	0	0	0	0	0	0	0	0	0	-13	-7,903	-8,404	-4,196
Vertically Integrated	-4,351,695	-6,124,481	-4,105,205	-17,003,748	-7,582,020	-5,439,909	-7,451,825	-6,458,002	-10,755,243	-8,683,788	-5,451,949	-10,128,796	-16,331,278	-6,783,881	-6,355,119	-7,510,147	-8,220,808	-4,596,972
100																		
Independent Supplier	-53,981	-104,225	-94,686	-307,729	-133,026	-112,901	-174,540	-144,304	-275,688	-218,464	-204,820	-356,810	-675,397	-378,251	-236,053	-298,928	-318,920	-193,316
Independent Thermal	-631,195	-1,029,027	-810,506	-2,423,590	-1,094,309	-931,178	-1,228,738	-983,439	-1,659,995	-1,256,929	-780,539	-1,376,140	-2,092,610	-963,610	-949,326	-1,131,595	-1,143,049	-584,812
Independent Wind	0	0	0	0	0	0	-2	-131	-6	-1	49	355	-108	207	-1,861	2,442	2,695	330
Interconnector	-588	-499	-343	-1,228	-4,539	-24,334	-30,527	-21,032	-45,112	-40,045	-26,640	-44,147	-67,751	-36,502	0	0	0	0
NULL	0	0	0	0	0	0	0	0	0	0	0	0	0	0	-9	-6,205	-6,685	-2,925
Vertically Integrated	-3,259,000	-4,603,346	-3,369,492	-13,670,178	-5,823,804	-4,383,718	-5,676,764	-4,956,081	-8,678,474	-6,692,378	-4,192,451	-7,893,137	-12,607,954	-5,282,584	-4,824,783	-5,930,744	-6,557,745	-3,415,195
250																		
Independent Supplier	-21,089	-41,241	-50,101	-142,576	-55,816	-54,563	-70,497	-61,896	-129,306	-97,078	-83,122	-158,361	-287,710	-186,243	-92,920	-136,259	-153,777	-82,452
Independent Thermal	-251,299	-407,379	-425,733	-1,125,248	-457,661	-453,720	-497,914	-421,650	-776,489	-559,754	-313,348	-613,332	-891,270	-472,657	-370,655	-517,603	-548,023	-252,300
Independent Wind	0	0	0	0	0	-1	-6	-80	-4	0	26	194	-43	281	-923	1,264	1,669	214
Interconnector	-273	-187	-171	-543	-2,027	-12,339	-12,606	-9,342	-20,356	-18,283	-10,752	-19,885	-28,463	-18,102	0	0	0	0
NULL	0	0	0	0	0	0	0	0	0	0	0	0	0	0	-4	-2,892	-3,181	-1,104
Vertically Integrated	-1,302,256	-1,819,882	-1,766,634	-6,335,542	-2,427,964	-2,120,710	-2,294,840	-2,122,391	-4,057,425	-2,999,697	-1,696,093	-3,511,872	-5,367,065	-2,579,263	-1,900,652	-2,709,766	-3,144,542	-1,467,695
350																		
Independent Supplier	-9,903	-19,023	-29,905	-72,137	-26,824	-29,937	-32,963	-30,107	-66,481	-46,523	-37,946	-78,400	-140,385	-108,212	-42,428	-68,482	-80,718	-38,378
Independent Thermal	-117,548	-189,943	-252,884	-574,215	-219,924	-249,384	-233,349	-201,871	-398,067	-270,058	-143,539	-305,065	-434,032	-272,563	-168,748	-261,604	-287,839	-118,314
Independent Wind	0	0	0	0	0	0	-2	-48	-2	1	18	101	-21	324	-563	721	1,128	126
Interconnector	-141	-89	-96	-282	-1,014	-7,097	-5,962	-4,667	-10,342	-8,889	-4,851	-10,045	-13,738	-10,880	0	0	0	0
NULL	0	0	0	0	0	0	0	0	0	0	0	0	0	0	-2	-1,502	-1,714	-500
Vertically Integrated	-612,592	-852,477	-1,048,284	-3,222,630	-1,164,724	-1,159,962	-1,075,504	-1,021,330	-2,075,762	-1,450,927	-779,952	-1,747,161	-2,616,246	-1,484,228	-867,386	-1,363,663	-1,642,300	-685,285

Table 8 - Total impacts of P305 scenarios on RCRC (£s) – Area A+B

Sum of rcrc_delta	Column Labels																	
	Live																	
	Single																	
	2010				2011				2012				2013				2014	
Row Labels	1	2	3	4	1	2	3	4	1	2	3	4	1	2	3	4	1	2
1																		
Independent Supplier	32,800	97,020	138,008	89,283	107,286	141,091	137,807	190,611	147,874	245,147	319,735	418,100	506,938	482,374	405,124	516,414	280,725	220,813
Independent Thermal	319,377	991,803	1,260,334	697,491	902,736	1,108,629	922,957	1,318,901	899,960	1,356,540	1,210,833	1,603,772	1,537,567	1,252,206	1,641,621	1,905,658	1,015,562	656,893
Independent Wind	0	1	0	0	0	13	-14	31	2	28	-80	137	22	-1,413	1,755	801	-667	-144
Interconnector	409	415	470	1,039	5,528	22,624	24,264	33,093	35,939	45,661	43,795	55,538	51,668	40,635	0	0	0	0
NULL	0	0	0	0	0	0	0	0	0	0	0	0	0	0	19	10,316	7,591	6,036
Vertically Integrated	1,762,816	4,701,077	5,343,988	3,808,886	5,082,211	5,603,538	4,268,509	6,969,052	4,753,921	6,990,152	6,523,368	9,218,783	9,392,478	7,167,679	8,348,286	10,246,362	5,772,845	3,753,783
50																		
Independent Supplier	49,344	119,247	153,748	148,092	135,496	155,471	182,030	220,398	191,773	296,244	357,784	477,613	616,991	549,738	442,916	558,362	328,147	259,395
Independent Thermal	510,566	1,215,192	1,395,440	1,146,458	1,127,347	1,225,051	1,243,252	1,520,663	1,170,445	1,647,176	1,356,852	1,829,162	1,874,587	1,423,486	1,795,248	2,066,531	1,181,724	775,184
Independent Wind	0	1	0	0	0	14	-15	30	2	28	-82	113	44	-1,668	1,909	236	-941	-179
Interconnector	511	553	529	1,332	6,001	25,375	31,135	37,457	43,316	54,855	48,662	62,846	63,199	47,392	0	0	0	0
NULL	0	0	0	0	0	0	0	0	0	0	0	0	0	0	20	11,201	8,582	6,601
Vertically Integrated	2,729,417	5,713,098	5,900,890	6,319,011	6,261,759	6,161,224	5,763,708	7,984,715	6,159,466	8,534,826	7,302,966	10,515,891	11,411,832	8,118,181	9,119,899	11,082,385	6,711,278	4,453,919
100																		
Independent Supplier	61,234	138,165	165,011	192,035	158,982	170,643	211,578	245,580	233,200	333,218	392,147	533,958	720,912	609,203	483,036	600,990	372,636	291,530
Independent Thermal	644,114	1,405,824	1,494,494	1,486,295	1,320,225	1,348,770	1,453,077	1,689,753	1,421,046	1,858,602	1,491,311	2,041,620	2,197,326	1,572,339	1,957,771	2,229,902	1,341,716	872,914
Independent Wind	0	1	0	0	0	15	-18	37	2	29	-85	92	64	-1,640	2,164	-314	-1,162	-214
Interconnector	591	655	572	1,518	6,609	28,328	36,167	40,777	50,178	61,193	53,064	69,361	74,018	53,228	0	0	0	0
NULL	0	0	0	0	0	0	0	0	0	0	0	0	0	0	22	12,156	9,530	7,059
Vertically Integrated	3,413,342	6,574,752	6,314,213	8,217,221	7,285,156	6,750,676	6,736,369	8,833,231	7,469,615	9,654,969	8,014,376	11,751,208	13,352,014	8,939,946	9,936,755	11,931,523	7,630,888	5,030,202
250																		
Independent Supplier	82,383	177,809	193,174	293,086	206,803	208,926	275,330	296,015	331,851	408,609	468,616	653,442	940,838	727,281	568,806	694,834	473,044	354,712
Independent Thermal	888,044	1,795,885	1,735,015	2,288,727	1,714,208	1,662,202	1,902,547	2,033,013	2,014,114	2,291,204	1,785,708	2,499,271	2,882,192	1,871,574	2,305,658	2,589,723	1,703,336	1,063,367
Independent Wind	0	1	0	0	0	14	-20	71	3	29	-100	-31	112	-1,567	2,724	-1,216	-1,841	-302
Interconnector	782	851	676	1,908	8,100	36,707	47,415	47,879	66,206	74,867	63,050	83,956	96,393	64,616	0	0	0	0
NULL	0	0	0	0	0	0	0	0	0	0	0	0	0	0	25	14,195	11,681	7,988
Vertically Integrated	4,667,504	8,307,109	7,312,769	12,739,531	9,377,669	8,226,584	8,811,880	10,558,132	10,568,078	11,955,232	9,586,471	14,379,686	17,459,616	10,580,042	11,684,857	13,793,323	9,702,839	6,149,957
350																		
Independent Supplier	90,359	193,797	207,827	340,186	226,805	226,732	301,050	317,368	377,472	443,326	500,528	706,612	1,033,878	780,684	603,468	737,100	522,493	383,443
Independent Thermal	982,330	1,951,896	1,859,005	2,660,655	1,877,593	1,809,942	2,084,081	2,180,526	2,288,570	2,490,310	1,906,359	2,704,198	3,171,879	2,007,576	2,444,863	2,751,570	1,879,106	1,150,980
Independent Wind	0	1	0	0	0	14	-17	93	4	29	-107	-103	127	-1,524	2,955	-1,644	-2,221	-369
Interconnector	873	921	729	2,076	8,767	40,680	52,057	51,025	73,246	81,393	67,249	90,511	105,684	69,558	0	0	0	0
NULL	0	0	0	0	0	0	0	0	0	0	0	0	0	0	27	15,131	12,686	8,382
Vertically Integrated	5,152,805	8,996,408	7,826,020	14,834,943	10,242,572	8,918,001	9,647,121	11,295,439	12,003,356	13,020,859	10,236,023	15,551,204	19,196,162	11,321,304	12,393,866	14,633,131	10,716,989	6,660,179

Table 9 - Total impacts of P305 scenarios on RCRC (£s) – Area A+B+C

Sum of rcrc_delta	Column Labels			
	RSP			
	Single			
	2013			
Row Labels	1	2	3	4
1				
Independent Supplier	541,818	497,358	438,543	172,546
Independent Thermal	1,646,499	1,292,496	1,773,294	688,373
Independent Wind	44	-1,503	1,793	1,337
Interconnector	54,695	42,279	0	0
NULL	0	0	20	3,807
Vertically Integrated	10,068,873	7,390,241	9,056,570	3,506,741
50				
Independent Supplier	654,066	559,480	474,693	189,414
Independent Thermal	1,992,192	1,450,340	1,919,374	755,588
Independent Wind	57	-1,745	1,935	913
Interconnector	66,485	48,565	0	0
NULL	0	0	22	4,212
Vertically Integrated	12,143,458	8,261,267	9,787,503	3,839,143
100				
Independent Supplier	756,576	617,646	511,479	207,082
Independent Thermal	2,308,929	1,595,625	2,068,607	826,119
Independent Wind	74	-1,715	2,183	515
Interconnector	77,164	54,218	0	0
NULL	0	0	23	4,645
Vertically Integrated	14,049,904	9,062,872	10,531,926	4,187,264
250				
Independent Supplier	977,182	736,040	601,495	248,053
Independent Thermal	2,994,561	1,895,522	2,433,697	989,242
Independent Wind	117	-1,632	2,773	-69
Interconnector	99,434	65,629	0	0
NULL	0	0	27	5,592
Vertically Integrated	18,165,575	10,707,904	12,372,274	4,995,379
350				
Independent Supplier	1,074,353	791,479	638,875	266,682
Independent Thermal	3,296,248	2,036,864	2,583,279	1,063,430
Independent Wind	131	-1,590	3,003	-329
Interconnector	109,117	70,831	0	0
NULL	0	0	28	6,025
Vertically Integrated	19,979,764	11,479,733	13,138,455	5,366,601

Table 10 - Total impacts of P305 scenarios on Net Positions (£s) – Area A

Sum of net_impact; Column Labels: Live / Twin

Row Labels	2010 1	2010 2	2010 3	2010 4	2011 1	2011 2	2011 3	2011 4	2012 1	2012 2	2012 3	2012 4	2013 1	2013 2	2013 3	2013 4	2014 1	2014 2
1																		
Independent Supplier	337,209	490,293	330,745	1,276,712	703,528	674,052	734,471	758,868	775,953	937,136	616,916	940,730	1,347,789	642,381	769,503	925,216	927,497	716,642
Independent Thermal	-562,524	-256,946	-284,925	-529,334	-586,556	-465,102	269,613	-418,063	-695,587	-620,729	-136,300	-577,916	-1,074,155	-581,151	-415,841	-593,967	-614,644	-403,922
Independent Wind	0	2	0	12	3	-1	21	-133	4	5	74	456	4,133	554	39,604	3,932	3,516	457
Interconnector	23,150	24,418	9,117	43,964	64,111	452	98,348	48,257	24,990	31,964	34,018	32,766	-6,836	13,872	76,051	50,885	68,074	17,656
NULL	0	0	0	0	0	0	0	0	0	0	0	0	2,551	34	2,044	51,983	105,267	37,687
Vertically Integrated	202,164	-257,766	-54,938	-791,353	-181,086	-209,400	-1,102,453	-388,928	-105,358	-348,375	-514,709	-396,035	-273,479	-75,688	-471,361	-438,049	-489,709	-368,521
50																		
Independent Supplier	245,129	349,610	276,462	980,676	525,592	541,883	550,430	559,448	627,382	684,056	473,954	743,558	1,068,193	496,221	600,129	753,974	755,935	533,057
Independent Thermal	-427,381	-195,221	-242,508	-376,597	-487,756	-407,376	208,761	-309,580	-556,360	-492,811	-116,368	-470,324	-877,824	-459,342	-340,343	-513,272	-483,109	-253,587
Independent Wind	0	1	0	9	2	1	13	-135	2	3	63	411	3,395	243	30,584	3,189	3,097	394
Interconnector	17,465	15,932	7,275	31,584	52,618	-1,826	45,090	42,359	19,242	22,295	26,683	22,755	-8,170	6,984	54,790	40,596	56,180	14,096
NULL	0	0	0	0	0	0	0	0	0	0	0	0	2,543	88	1,191	38,650	80,410	29,972
Vertically Integrated	164,787	-170,323	-41,228	-635,673	-90,457	-132,682	-804,294	-292,092	-90,265	-213,543	-384,332	-296,400	-188,135	-44,193	-346,350	-323,137	-412,511	-323,932
100																		
Independent Supplier	182,972	249,642	226,643	772,026	391,142	432,010	420,546	412,588	498,817	524,594	352,896	576,630	820,577	392,943	454,224	588,003	594,420	396,774
Independent Thermal	-321,150	-158,815	-206,209	-324,096	-385,102	-348,641	132,238	-242,027	-433,260	-382,587	-95,513	-369,003	-682,637	-367,157	-258,110	-416,502	-388,538	-180,916
Independent Wind	0	1	0	7	2	3	4	-126	0	3	56	373	2,540	240	24,395	2,470	2,724	341
Interconnector	13,843	10,494	5,610	24,128	38,877	-2,640	24,721	31,989	11,829	14,618	15,300	18,396	-9,947	2,926	35,376	30,641	45,509	11,171
NULL	0	0	0	0	0	0	0	0	0	0	0	0	1,374	69	904	28,953	64,875	23,313
Vertically Integrated	124,335	-101,322	-26,044	-472,065	-44,919	-80,731	-577,508	-202,423	-77,385	-156,627	-272,739	-226,396	-131,906	-29,021	-256,788	-233,563	-318,988	-250,682
250																		
Independent Supplier	68,370	79,447	118,541	346,452	153,805	201,299	164,788	161,852	220,732	229,419	133,638	254,450	349,845	194,331	168,827	256,254	276,595	172,162
Independent Thermal	-125,423	-85,793	-121,202	-141,572	-182,267	-191,568	33,981	-123,761	-194,103	-184,191	-30,824	-144,447	-289,864	-187,428	-104,441	-189,236	-199,311	-77,733
Independent Wind	0	0	0	3	1	0	-4	-78	-2	2	29	202	903	299	9,717	1,277	1,684	219
Interconnector	6,431	3,538	2,156	10,375	12,645	-2,501	8,574	12,812	-452	3,855	1,291	9,799	-5,926	-437	10,719	11,803	18,120	5,372
NULL	0	0	0	0	0	0	0	0	0	0	0	0	459	25	253	12,895	33,836	8,907
Vertically Integrated	50,622	2,809	505	-215,259	15,816	-7,230	-207,340	-50,826	-26,176	-49,084	-104,134	-120,003	-55,416	-6,790	-85,075	-92,993	-130,924	-108,926
350																		
Independent Supplier	30,611	34,604	69,480	174,231	71,320	107,267	75,723	73,603	111,884	109,527	58,848	127,071	171,833	112,679	77,411	128,583	150,795	83,167
Independent Thermal	-53,757	-49,876	-76,483	-69,602	-95,927	-108,820	17,037	-72,089	-106,089	-98,641	-13,715	-64,432	-137,789	-112,689	-52,565	-91,506	-109,500	-35,222
Independent Wind	0	0	0	2	0	1	-1	-47	-1	2	20	105	421	336	4,247	728	1,136	128
Interconnector	3,011	1,619	1,030	4,991	7,021	-1,911	3,958	5,214	-756	1,195	-94	5,557	-3,231	-1,286	4,203	5,432	8,387	2,459
NULL	0	0	0	0	0	0	0	0	0	0	0	0	197	15	66	6,634	20,074	4,171
Vertically Integrated	20,135	13,653	5,973	-109,622	17,585	3,464	-96,717	-6,681	-5,038	-12,083	-45,058	-68,301	-31,431	945	-33,362	-49,871	-70,893	-54,703

Table 11 - Total impacts of P305 scenarios on Net Positions (£s) – Area A+B

Sum of net_impact	Column Labels																	
	Live																	
	Single																	
	2010				2011				2012				2013				2014	
Row Labels	1	2	3	4	1	2	3	4	1	2	3	4	1	2	3	4	1	2
1																		
Independent Supplier	-456,603	-935,958	-779,325	-3,815,295	-2,058,847	-1,561,219	-1,989,471	-1,379,505	-1,337,757	-1,581,779	-1,266,866	-2,041,753	-3,537,943	-1,076,011	-2,399,095	-2,951,184	-1,948,941	-874,785
Independent Thermal	-842,122	-888,786	-517,296	-2,523,075	-1,246,945	-507,070	-493,416	-896,873	-1,818,925	-2,261,804	-928,537	-1,123,767	-2,283,667	-485,685	-674,803	-434,826	-598,517	-397,936
Independent Wind	0	-59	0	5	-15	4	-38	-10	-73	-52	-142	8	-1,305	-1,522	-166,537	587	-895	-246
Interconnector	-88,762	-68,885	-69,745	-186,253	-116,010	-138,216	-100,334	-217,952	-234,519	-67,201	-177,476	-153,065	-115,975	-125,666	-164,587	-158,800	-108,905	-45,107
NULL	0	0	0	0	0	0	0	0	0	0	0	0	91	-2,477	-6,419	-322,115	-305,715	-106,702
Vertically Integrated	1,387,487	1,893,688	1,366,367	6,524,619	3,421,816	2,206,500	2,583,259	2,494,339	3,391,273	3,910,836	2,373,020	3,318,576	5,938,798	1,691,361	3,411,441	3,866,337	2,962,972	1,424,775
50																		
Independent Supplier	-490,048	-975,483	-785,031	-3,651,645	-2,058,860	-1,571,932	-1,915,225	-1,454,425	-1,381,331	-1,677,129	-1,316,366	-2,072,990	-3,466,557	-1,101,943	-2,378,582	-2,938,197	-1,960,561	-940,459
Independent Thermal	-683,059	-774,848	-460,221	-2,175,850	-1,099,343	-443,941	-518,281	-771,215	-1,585,753	-2,005,274	-854,970	-978,152	-1,982,357	-363,771	-597,891	-351,992	-459,304	-285,046
Independent Wind	0	-57	0	2	-14	5	-40	-10	-70	-47	-142	-12	-1,554	-1,776	-167,660	27	-1,162	-275
Interconnector	-87,466	-71,146	-67,719	-176,867	-118,590	-136,182	-135,823	-209,186	-229,102	-73,309	-173,080	-156,963	-113,845	-127,697	-177,639	-161,817	-112,895	-44,526
NULL	0	0	0	0	0	0	0	0	0	0	0	0	83	-2,179	-7,056	-314,782	-308,578	-101,026
Vertically Integrated	1,260,574	1,821,534	1,312,971	6,004,360	3,276,808	2,152,049	2,569,369	2,434,836	3,196,255	3,755,760	2,344,559	3,208,116	5,564,230	1,597,367	3,328,828	3,766,761	2,842,499	1,371,331
100																		
Independent Supplier	-513,217	-1,001,738	-801,364	-3,528,688	-2,038,607	-1,587,326	-1,885,469	-1,508,208	-1,419,046	-1,723,263	-1,362,440	-2,103,537	-3,402,049	-1,124,123	-2,374,427	-2,959,767	-1,973,485	-975,861
Independent Thermal	-548,945	-685,347	-406,476	-1,980,308	-957,748	-375,400	-562,098	-683,944	-1,376,739	-1,798,241	-793,681	-834,999	-1,680,490	-273,366	-496,261	-249,765	-350,631	-207,066
Independent Wind	0	-51	0	0	-14	6	-44	-4	-67	-44	-143	-30	-2,155	-1,748	-164,125	-518	-1,376	-306
Interconnector	-84,620	-71,812	-66,506	-171,159	-124,326	-132,148	-142,369	-208,965	-225,381	-80,429	-176,252	-155,758	-112,499	-127,438	-189,819	-165,185	-117,373	-43,877
NULL	0	0	0	0	0	0	0	0	0	0	0	0	-1,073	-2,093	-7,125	-304,902	-302,752	-99,017
Vertically Integrated	1,146,782	1,758,948	1,274,346	5,680,154	3,120,695	2,094,868	2,589,980	2,401,120	3,021,233	3,601,977	2,332,516	3,094,323	5,198,266	1,528,769	3,231,757	3,680,137	2,745,616	1,326,126
250																		
Independent Supplier	-552,256	-1,049,949	-836,213	-3,272,331	-1,987,445	-1,662,596	-1,877,325	-1,595,640	-1,491,606	-1,830,262	-1,446,108	-2,179,168	-3,288,829	-1,190,716	-2,413,509	-3,014,441	-2,015,419	-1,024,361
Independent Thermal	-297,208	-522,943	-297,296	-1,478,311	-661,636	-200,699	-592,398	-504,575	-956,741	-1,416,796	-667,056	-495,671	-1,086,822	-82,759	-312,185	386	-125,446	-59,757
Independent Wind	0	-44	-1	-4	-13	5	-47	32	-60	-38	-157	-149	-3,165	-1,676	-158,210	-1,414	-2,041	-385
Interconnector	-79,851	-68,720	-65,018	-162,308	-136,933	-122,836	-138,512	-205,505	-212,326	-85,885	-177,657	-149,477	-99,737	-121,044	-200,941	-171,278	-131,885	-43,970
NULL	0	0	0	0	0	0	0	0	0	0	0	0	-1,971	-2,096	-7,386	-287,004	-292,626	-98,830
Vertically Integrated	929,315	1,641,656	1,198,527	4,912,954	2,786,026	1,986,125	2,608,282	2,305,687	2,660,732	3,332,981	2,290,978	2,824,464	4,480,523	1,398,290	3,092,230	3,473,750	2,567,416	1,227,303
350																		
Independent Supplier	-563,840	-1,057,534	-858,790	-3,176,796	-1,970,706	-1,697,479	-1,891,966	-1,624,363	-1,521,461	-1,885,046	-1,479,363	-2,222,670	-3,264,834	-1,229,730	-2,426,860	-3,033,849	-2,037,020	-1,044,673
Independent Thermal	-209,327	-459,716	-242,858	-1,278,286	-541,895	-110,947	-583,845	-425,081	-799,931	-1,256,918	-629,895	-362,483	-858,390	-3,299	-248,591	106,233	-15,627	11,044
Independent Wind	0	-40	-1	-5	-13	5	-44	55	-56	-36	-163	-219	-3,302	-1,635	-156,705	-1,841	-2,416	-450
Interconnector	-79,480	-67,733	-64,067	-160,463	-137,244	-118,448	-136,052	-201,753	-201,611	-87,129	-174,597	-145,529	-93,971	-117,576	-203,211	-172,880	-136,583	-44,781
NULL	0	0	0	0	0	0	0	0	0	0	0	0	-2,218	-2,099	-7,463	-281,765	-291,863	-98,872
Vertically Integrated	852,647	1,585,024	1,165,716	4,615,550	2,649,858	1,926,869	2,611,907	2,251,140	2,523,058	3,229,128	2,284,016	2,730,900	4,222,714	1,354,339	3,042,829	3,384,099	2,483,508	1,177,731

Table 12 - Total impacts of P305 scenarios on Net Positions (£s) – Area A+B+C

Sum of net_impact	Column Labels			
	RSP			
	Single			
	2013			
Row Labels	1	2	3	4
1				
Independent Supplier	-3,584,690	-1,254,792	-2,651,268	-864,272
Independent Thermal	-2,148,153	-458,257	-432,982	-230,666
Independent Wind	-2,122	-1,616	-175,473	1,263
Interconnector	-116,686	-125,288	-165,691	-52,038
NULL	-807	-2,514	-6,685	-119,004
Vertically Integrated	5,852,457	1,842,466	3,432,098	1,264,716
50				
Independent Supplier	-3,517,322	-1,280,857	-2,628,359	-854,689
Independent Thermal	-1,821,499	-353,921	-335,121	-180,097
Independent Wind	-2,088	-1,857	-175,130	841
Interconnector	-114,355	-123,114	-178,750	-52,613
NULL	-806	-2,216	-7,286	-115,275
Vertically Integrated	5,456,068	1,761,964	3,324,647	1,201,833
100				
Independent Supplier	-3,442,629	-1,289,864	-2,615,071	-861,046
Independent Thermal	-1,506,998	-259,738	-255,964	-128,041
Independent Wind	-2,523	-1,826	-168,995	445
Interconnector	-114,698	-124,378	-187,964	-54,133
NULL	-1,475	-2,130	-7,331	-109,186
Vertically Integrated	5,068,321	1,677,936	3,235,325	1,151,961
250				
Independent Supplier	-3,317,721	-1,326,551	-2,611,245	-858,112
Independent Thermal	-884,200	-52,586	-84,643	-1,750
Independent Wind	-3,366	-1,742	-159,175	-136
Interconnector	-103,168	-119,587	-208,001	-57,195
NULL	-2,548	-2,133	-7,647	-99,374
Vertically Integrated	4,311,000	1,502,598	3,070,710	1,016,568
350				
Independent Supplier	-3,261,019	-1,356,732	-2,604,932	-854,278
Independent Thermal	-632,622	29,916	-18,099	57,320
Independent Wind	-3,469	-1,701	-157,440	-395
Interconnector	-98,439	-116,012	-211,397	-57,939
NULL	-2,741	-2,136	-7,758	-96,639
Vertically Integrated	3,998,287	1,446,665	2,999,626	951,930

Distributional effects (£/MWh)

Following its publication alongside the Assessment Consultation, the Workgroup and industry respondents provided feedback on our historical analysis.

Some members of the Workgroup and respondents were keen for further analysis to be completed that demonstrated the distributional effects that P305 might have. That is, how different types of party might be affected. To enable a review of the distributional effects, Workgroup members supported the identification of distributional effects using a volume weighted approach (£/MWh) at party type and supplier type level. The distributional analysis would enable a fairer comparison of the effects of P305 across party types.

We have completed this additional analysis and a summary of our findings is provided below.

Our methodology

Using the output from our original historical analysis we calculated average volume weighted net positions, changes in imbalance cashflows and changes in RCRC for different party and supplier types.

Example - average volume weighted net position

To do this, first, we calculated, at Settlement Period level, the sum of net positions[11] of individual Energy Accounts belonging to a defined category of Party or Supplier (see below) and divided this by the sum of those Energy Accounts' absolute Credited Energy. Finally, based on the Settlement Period values, an average of all Settlement Period volume weighted net positions in a quarter was calculated.

In summary, average volume weighted values were calculated using the following approach:

$$= \frac{1}{j\epsilon Q} \sum_{j\epsilon Q} \left(\frac{\sum_a (NetPosition_{aj}^{Prod} + NetPosition_{aj}^{Cons})}{\sum_a (|QCE_{aj}^{Prod}| + |QCE_{aj}^{Cons}|)} \right)$$

where:

a	is an Energy Accounts belonging to a Party or Supplier Type;
j	is a Settlement Period;
Q	is a calendar quarter; and
QCE	is a volume of Credited Energy.

Party and Supplier Types

We have aggregated data based on Party and Supplier Types used by Ofgem as part of its EBSCR analysis and which we subsequently used as part of our analysis for P304.

Table 13

List of Party and Supplier Types	
Party Types	Supplier Types
• Independent Supplier • Independent Thermal • Vertically Integrated • Independent Wind • Interconnector	• I&C • I&C + SME • Independent Domestic • Renewables Aggregator • Renewables Supplier • SME

The Parties represented in the Supplier Types do not include any Vertically Integrated Parties.

Please note that not all BSC Parties are represented by a Party Type or Supplier Type. This is because the categorisation of Parties was agreed on a voluntary basis by Parties confirming that they were happy to be categorised.

As a consequence we believe that the results for some Party Types may not be truly representative or add to our analysis, e.g. the Independent Wind type. Therefore, whilst our underlying analysis produced results based on all types described above, we have not presented the results for Independent Wind and Interconnectors below.

[11] A party's net position (£) is the sum of the change in imbalance cashflow (£) and change in RCRC (£) between the current baseline and P305.

Summary of distributional effects – Party type

Figures 29 to 40 illustrate the distributional effects of P305 on different party types. Negative values represent a reduction in charges or payments.

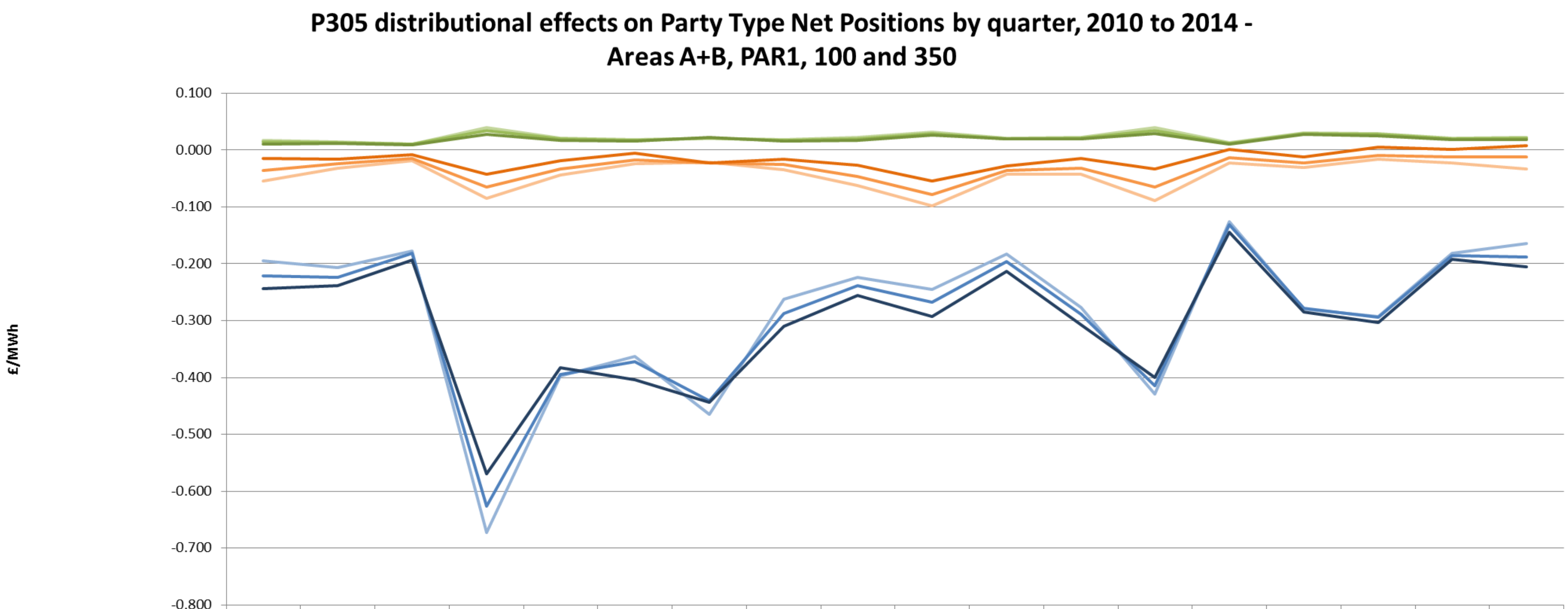
Net positions

Independent Suppliers benefitted most from the P305 changes to historical prices and imbalance positions. Independent Suppliers' average net positions were ~£0.3/MWh better off between 2010 and 2014. However, these benefits ranged from reductions of ~£0.13/MWh in Q2 2013 to ~£0.67/MWh in Q4 2010.

Independent Thermal parties also enjoyed a benefit under P305 proposals, although the reduction in their average net positions was more modest at between ~£0.043/MWh and ~£0.016/MWh. Compared to Independent Suppliers, the benefits to Independent Thermal parties varied much less over the four year period.

Vertically Integrated parties experienced an increase in their average net positions in all quarters of ~£0.02/MWh. Like Independent Thermal parties, the range of results for Vertically Integrated parties was limited compared to Independent Suppliers. Vertically Integrated parties average net position ranged from between an increase of £0.009/MWh and £0.04/MWh.

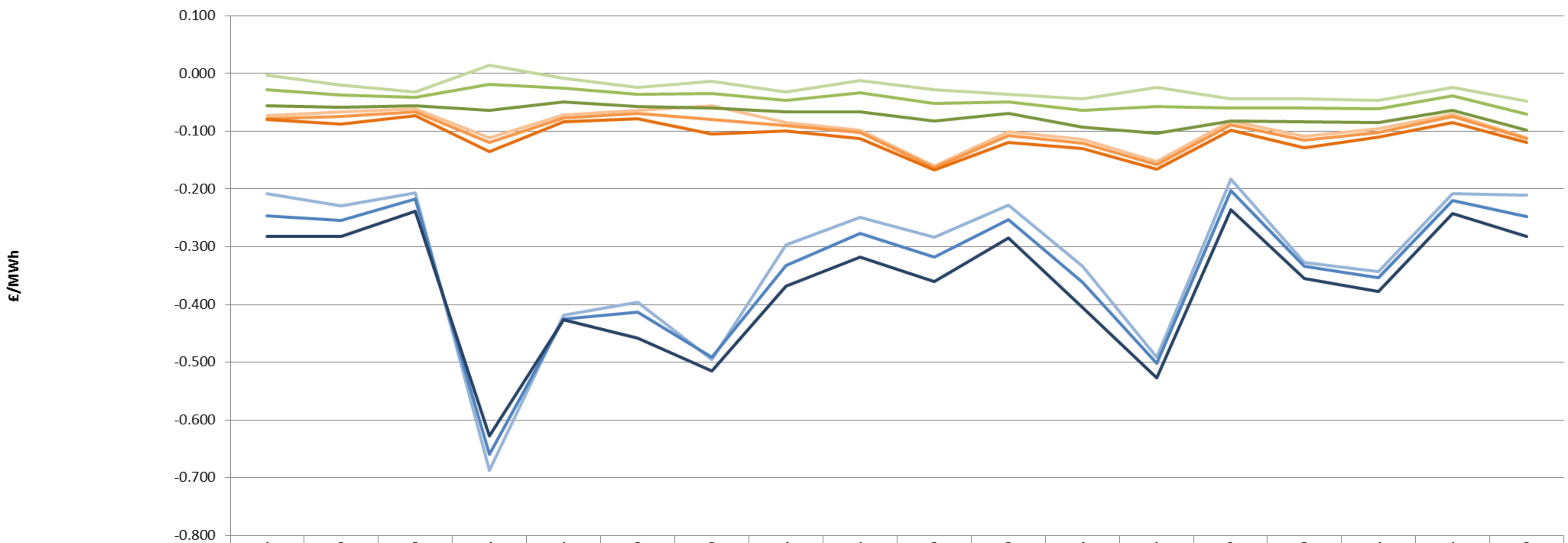
Figure 29



	2010 Q1	2010 Q2	2010 Q3	2010 Q4	2011 Q1	2011 Q2	2011 Q3	2011 Q4	2012 Q1	2012 Q2	2012 Q3	2012 Q4	2013 Q1	2013 Q2	2013 Q3	2013 Q4	2014 Q1	2014 Q2
Independent Supplier - 1	-0.194	-0.207	-0.177	-0.673	-0.398	-0.363	-0.464	-0.262	-0.224	-0.245	-0.183	-0.277	-0.430	-0.126	-0.280	-0.293	-0.181	-0.165
Independent Supplier - 100	-0.221	-0.224	-0.181	-0.627	-0.394	-0.372	-0.442	-0.288	-0.238	-0.267	-0.197	-0.288	-0.414	-0.132	-0.278	-0.295	-0.185	-0.188
Independent Supplier - 350	-0.244	-0.239	-0.193	-0.569	-0.383	-0.403	-0.443	-0.310	-0.256	-0.293	-0.214	-0.308	-0.400	-0.144	-0.285	-0.304	-0.192	-0.205
Independent Thermal - 1	-0.055	-0.032	-0.019	-0.085	-0.043	-0.024	-0.021	-0.034	-0.062	-0.098	-0.042	-0.043	-0.088	-0.023	-0.031	-0.016	-0.023	-0.033
Independent Thermal - 100	-0.036	-0.024	-0.015	-0.065	-0.033	-0.018	-0.023	-0.026	-0.047	-0.078	-0.036	-0.032	-0.064	-0.013	-0.023	-0.009	-0.013	-0.012
Independent Thermal - 350	-0.014	-0.016	-0.008	-0.042	-0.019	-0.005	-0.023	-0.016	-0.027	-0.055	-0.028	-0.014	-0.033	0.001	-0.011	0.005	0.002	0.008
Vertically Integrated - 1	0.018	0.015	0.011	0.039	0.022	0.018	0.022	0.018	0.022	0.032	0.021	0.023	0.040	0.014	0.030	0.029	0.021	0.022
Vertically Integrated - 100	0.015	0.014	0.010	0.034	0.020	0.018	0.022	0.017	0.020	0.030	0.020	0.022	0.035	0.012	0.029	0.028	0.020	0.021
Vertically Integrated - 350	0.011	0.012	0.009	0.028	0.017	0.016	0.022	0.016	0.017	0.027	0.020	0.019	0.028	0.011	0.027	0.026	0.018	0.019

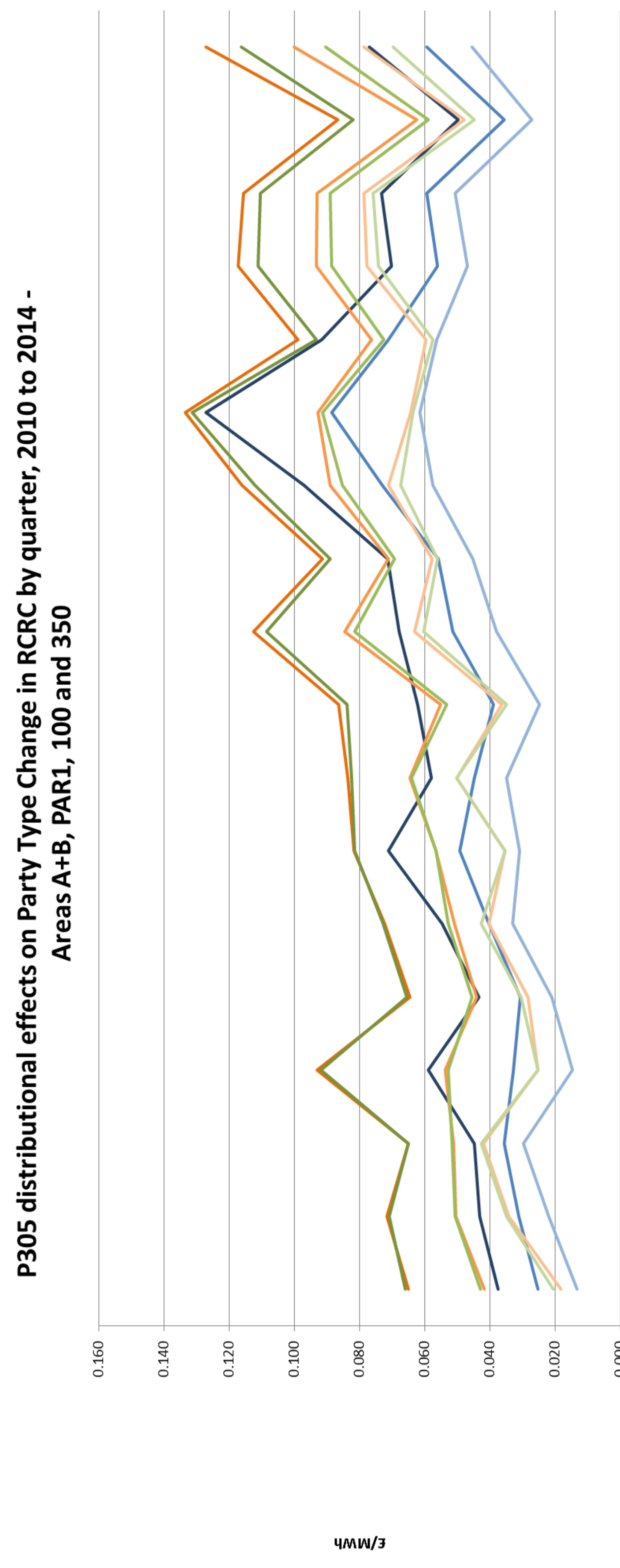
Figure 30

P305 distributional effects on Party Type Change in Imbalance Cashflow by quarter, 2010 to 2014 - Areas A+B, PAR1, 100 and 350



	2010				2011				2012				2013				2014	
	1	2	3	4	1	2	3	4	1	2	3	4	1	2	3	4	1	2
Independent Supplier - 1	-0.208	-0.229	-0.206	-0.687	-0.419	-0.396	-0.495	-0.297	-0.249	-0.283	-0.228	-0.334	-0.491	-0.182	-0.327	-0.343	-0.209	-0.210
Independent Supplier - 100	-0.246	-0.255	-0.217	-0.660	-0.425	-0.413	-0.491	-0.333	-0.277	-0.318	-0.252	-0.361	-0.502	-0.203	-0.334	-0.354	-0.221	-0.248
Independent Supplier - 350	-0.282	-0.282	-0.238	-0.628	-0.426	-0.458	-0.515	-0.368	-0.318	-0.360	-0.285	-0.405	-0.527	-0.236	-0.355	-0.377	-0.242	-0.282
Independent Thermal - 1	-0.073	-0.066	-0.061	-0.111	-0.072	-0.064	-0.056	-0.084	-0.099	-0.161	-0.100	-0.114	-0.153	-0.082	-0.108	-0.095	-0.071	-0.112
Independent Thermal - 100	-0.078	-0.074	-0.066	-0.119	-0.077	-0.069	-0.079	-0.090	-0.102	-0.163	-0.107	-0.121	-0.157	-0.089	-0.116	-0.102	-0.075	-0.112
Independent Thermal - 350	-0.079	-0.087	-0.073	-0.135	-0.083	-0.078	-0.105	-0.099	-0.113	-0.167	-0.120	-0.130	-0.166	-0.098	-0.129	-0.111	-0.085	-0.119
Vertically Integrated - 1	-0.003	-0.020	-0.032	0.014	-0.009	-0.024	-0.014	-0.032	-0.012	-0.028	-0.035	-0.044	-0.024	-0.044	-0.044	-0.047	-0.023	-0.048
Vertically Integrated - 100	-0.028	-0.037	-0.041	-0.019	-0.026	-0.035	-0.035	-0.046	-0.033	-0.052	-0.049	-0.063	-0.056	-0.060	-0.060	-0.061	-0.039	-0.070
Vertically Integrated - 350	-0.055	-0.059	-0.055	-0.064	-0.048	-0.057	-0.060	-0.066	-0.067	-0.082	-0.069	-0.093	-0.103	-0.082	-0.084	-0.085	-0.063	-0.098

Figure 31



	2010				2011				2012				2013				2014	
	1	2	3	4	1	2	3	4	1	2	3	4	1	2	3	4	1	2
Independent Supplier - 1	0.013	0.022	0.030	0.015	0.021	0.033	0.031	0.035	0.025	0.038	0.045	0.057	0.062	0.056	0.047	0.051	0.027	0.046
Independent Supplier - 100	0.025	0.031	0.036	0.033	0.031	0.040	0.049	0.045	0.039	0.051	0.056	0.073	0.088	0.071	0.056	0.059	0.036	0.059
Independent Supplier - 350	0.038	0.043	0.045	0.059	0.043	0.055	0.071	0.058	0.062	0.068	0.071	0.097	0.127	0.092	0.070	0.073	0.050	0.077
Independent Thermal - 1	0.018	0.034	0.042	0.025	0.028	0.040	0.035	0.050	0.036	0.063	0.058	0.071	0.064	0.060	0.078	0.079	0.048	0.079
Independent Thermal - 100	0.042	0.050	0.051	0.054	0.044	0.051	0.057	0.064	0.055	0.085	0.071	0.089	0.093	0.076	0.093	0.093	0.062	0.100
Independent Thermal - 350	0.065	0.072	0.065	0.093	0.064	0.072	0.082	0.084	0.086	0.112	0.091	0.116	0.134	0.099	0.117	0.116	0.087	0.127
Vertically Integrated - 1	0.021	0.035	0.043	0.025	0.030	0.043	0.035	0.050	0.035	0.060	0.056	0.067	0.064	0.057	0.074	0.076	0.045	0.070
Vertically Integrated - 100	0.043	0.051	0.052	0.053	0.045	0.053	0.057	0.064	0.053	0.081	0.069	0.085	0.091	0.073	0.089	0.089	0.059	0.090
Vertically Integrated - 350	0.066	0.071	0.065	0.092	0.065	0.073	0.081	0.083	0.084	0.109	0.089	0.112	0.131	0.093	0.111	0.110	0.082	0.116

Figure 32

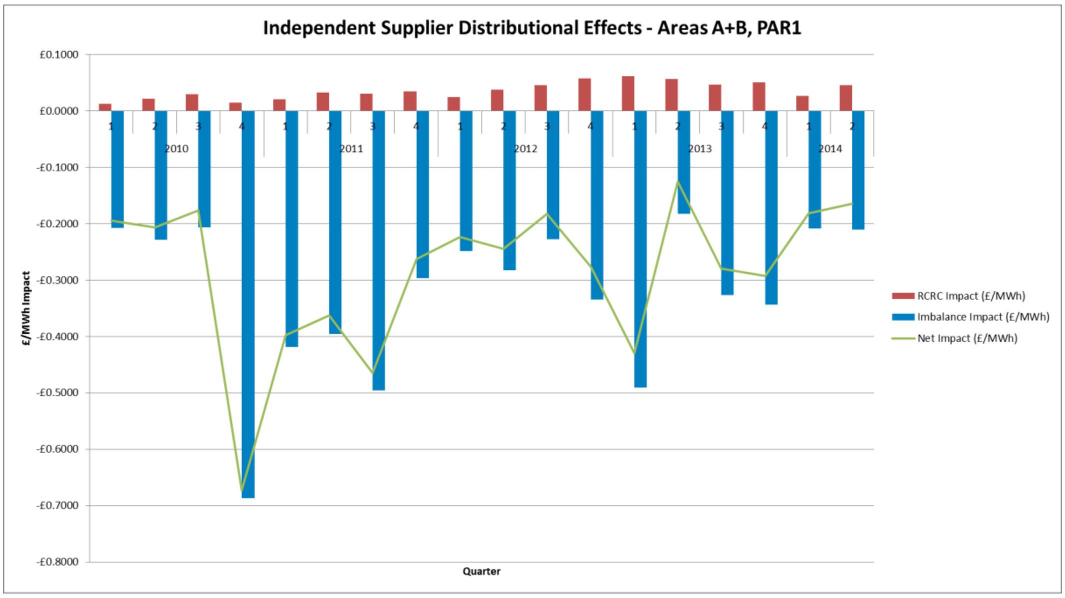


Figure 33

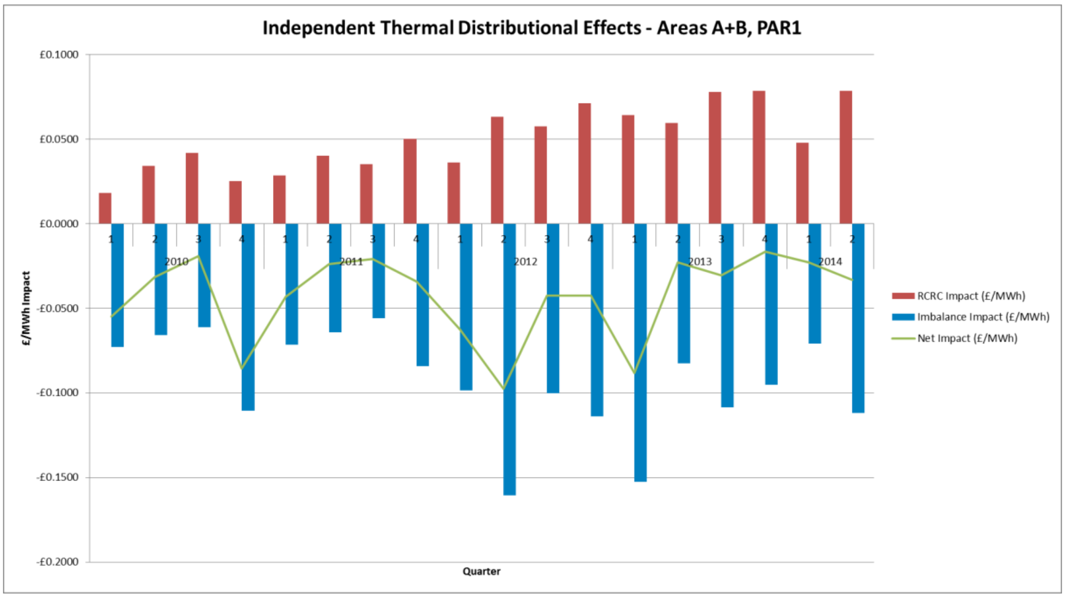


Figure 34

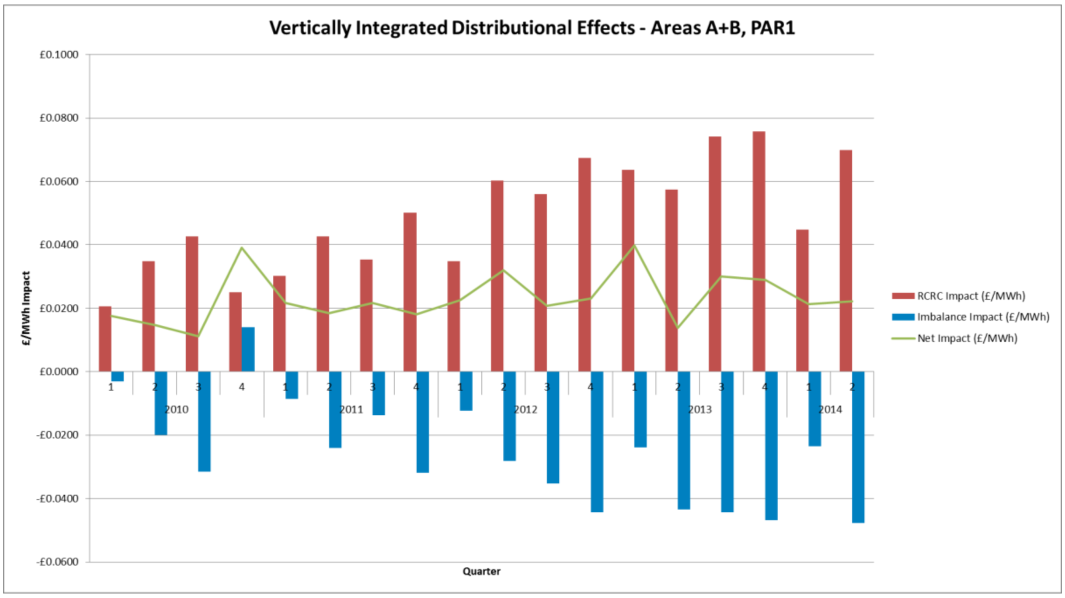


Figure 35

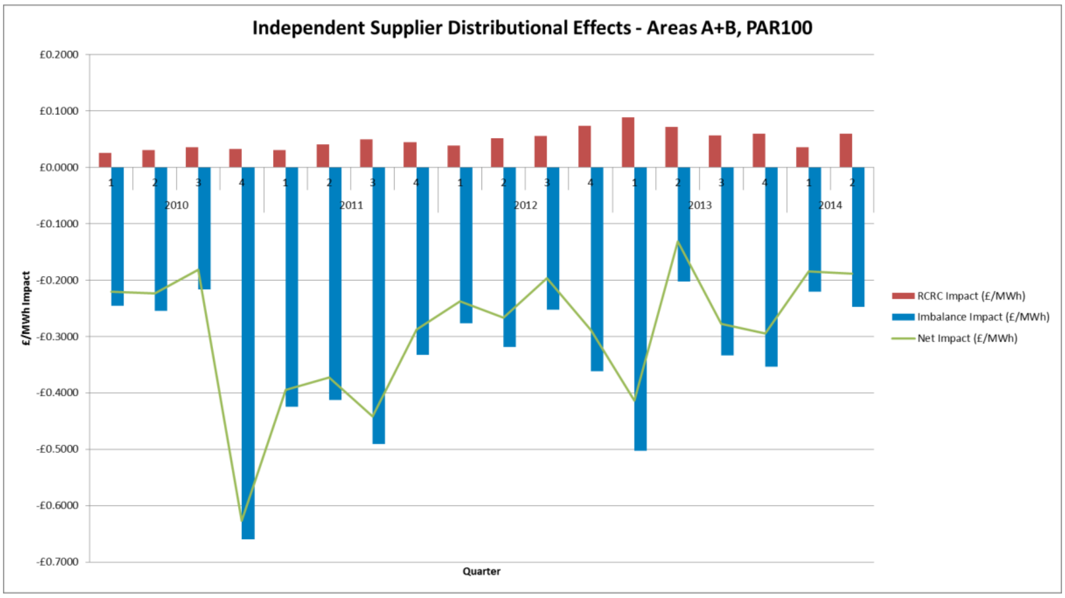


Figure 36

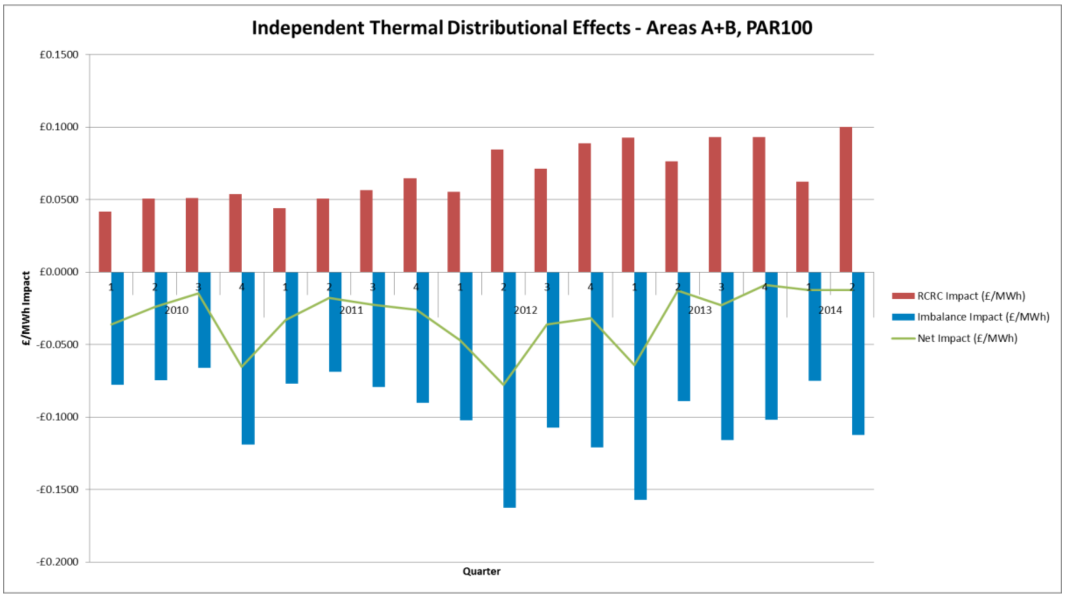


Figure 37

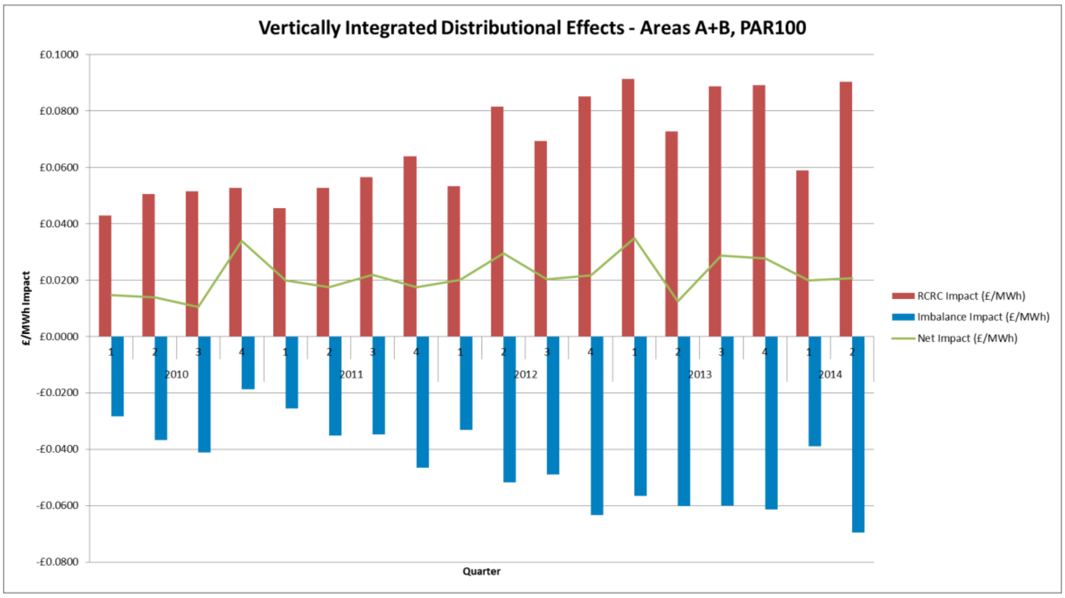


Figure 38

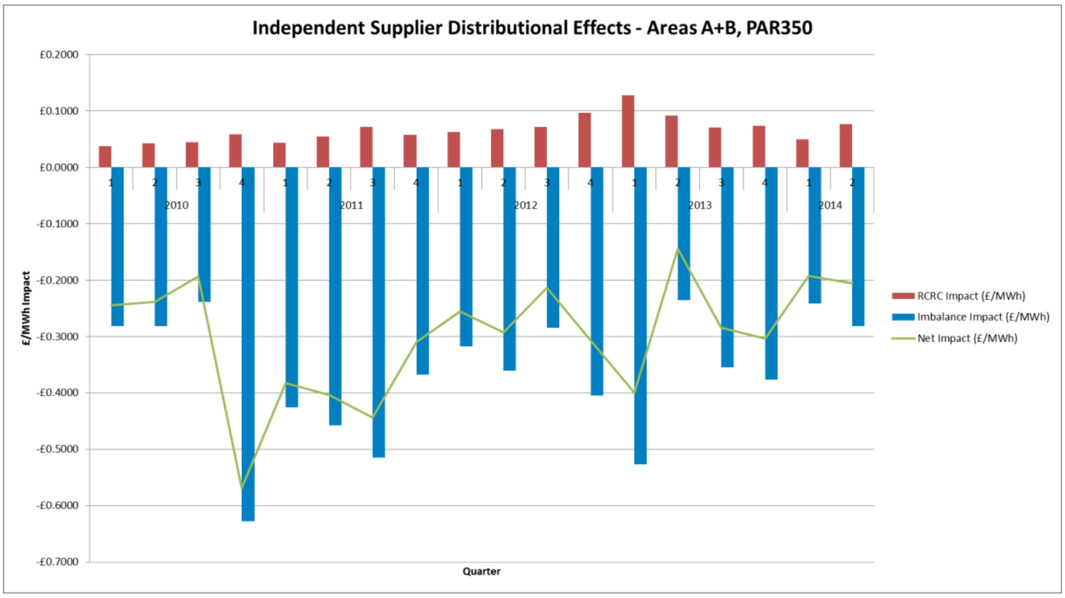


Figure 39

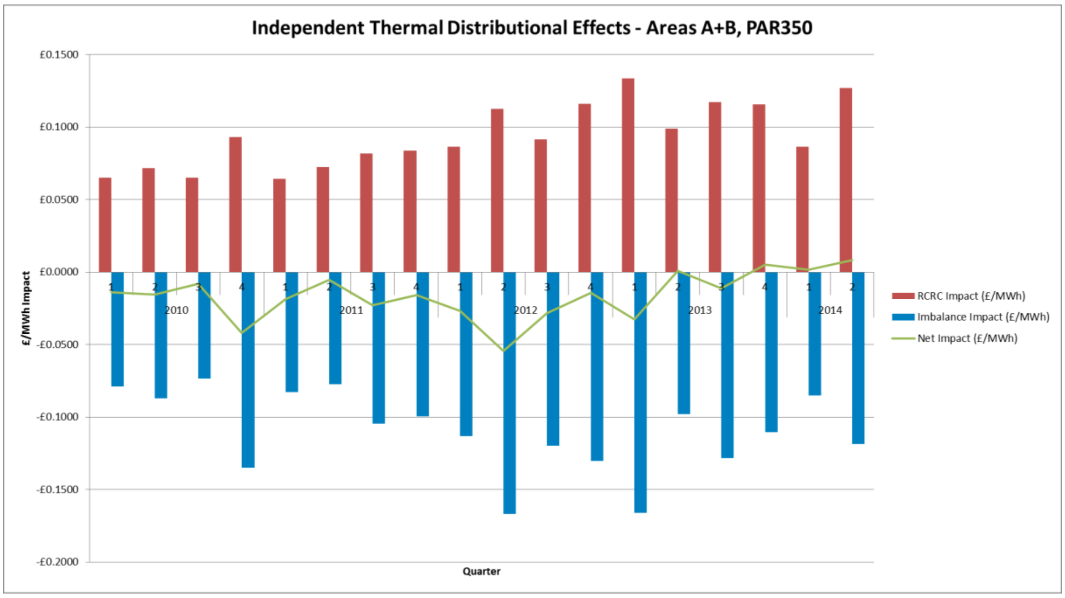
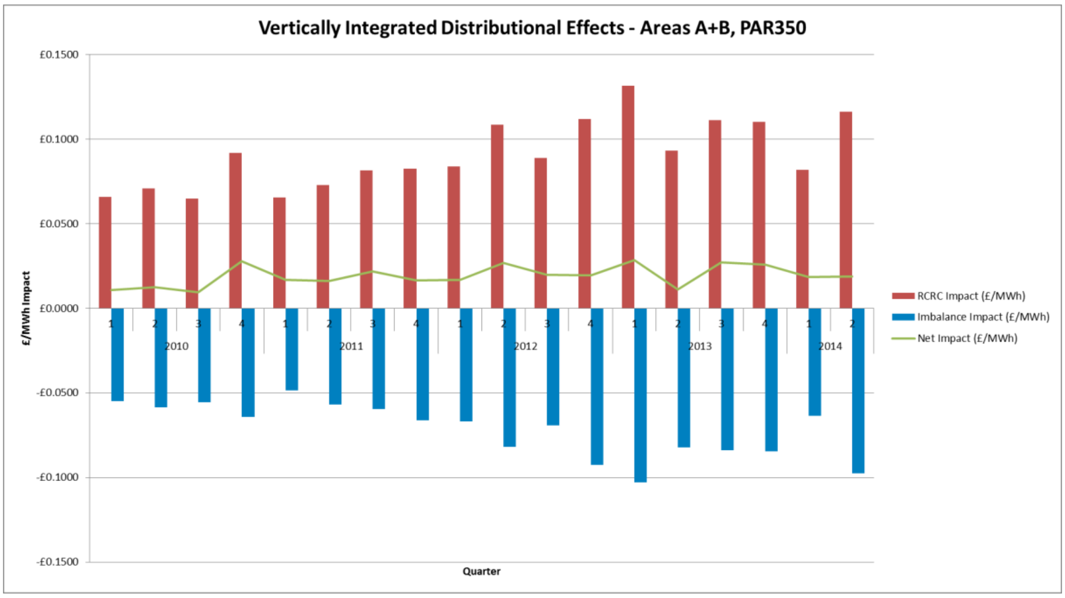


Figure 40



Summary of distributional effects – Supplier Types

Figures 41 to 61 illustrate the distributional effects of P305 on different Supplier Types. Negative values represent a reduction in charges or payments.

Net positions

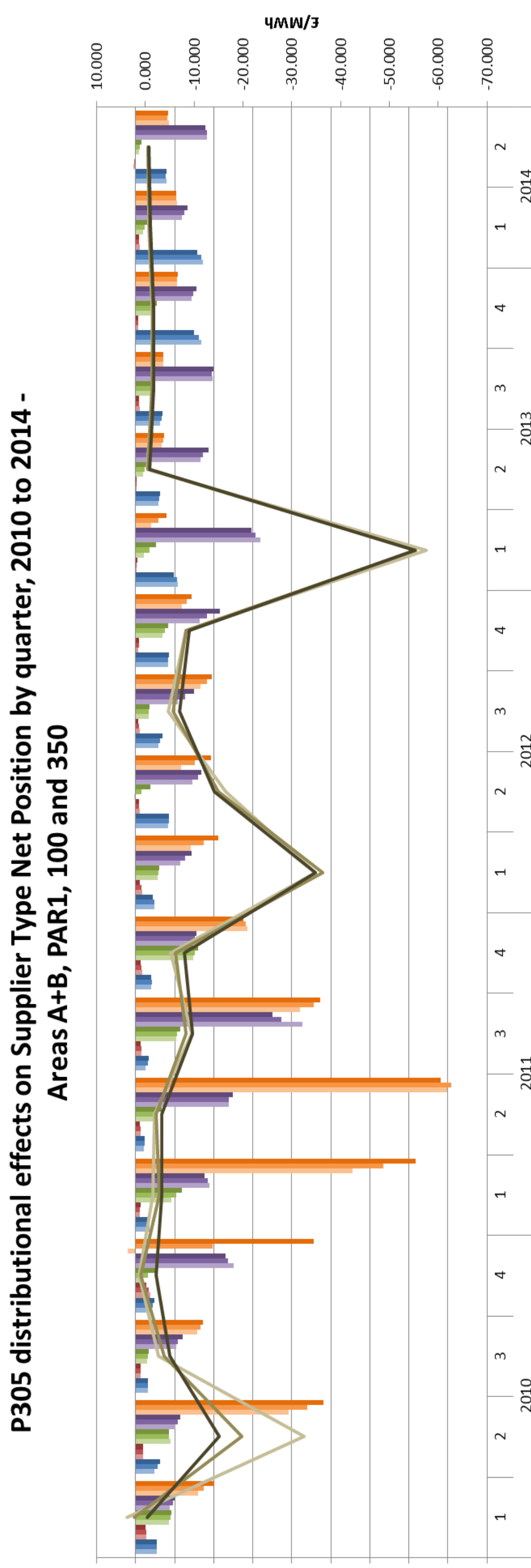
All Supplier Types typically experienced an average reduction in their net positions under P305. Bearing in mind that the Supplier Types do not include any Vertically Integrated suppliers, our analysis of distributional effects reflects our overall analysis set out above.

Of all Supplier Types, Renewable Suppliers would have benefitted the most under P305. Renewable Suppliers' average net positions reduced ~£9.5/MWh across 2010 to 2014. However, the range of quarterly average net positions ranged from an increase in net position of £3.7/MWh in Q1 2010 to a reduction in net position of £57.6/MWh Q1 2013.

SME Suppliers experienced the next best overall reduction in net position of ~£1.1/MWh. Although the range of benefit ranged from a reduction of £0.205/MWh to a reduction of £4.04/MWh.

Whilst SME Suppliers fared comparatively well, Industrial and Commercial (I&C) + SME Suppliers experienced the least benefit of all Supplier Types. I&C + SME suppliers only experienced a reduction in net position of ~£0.06/MWh.

Figure 41

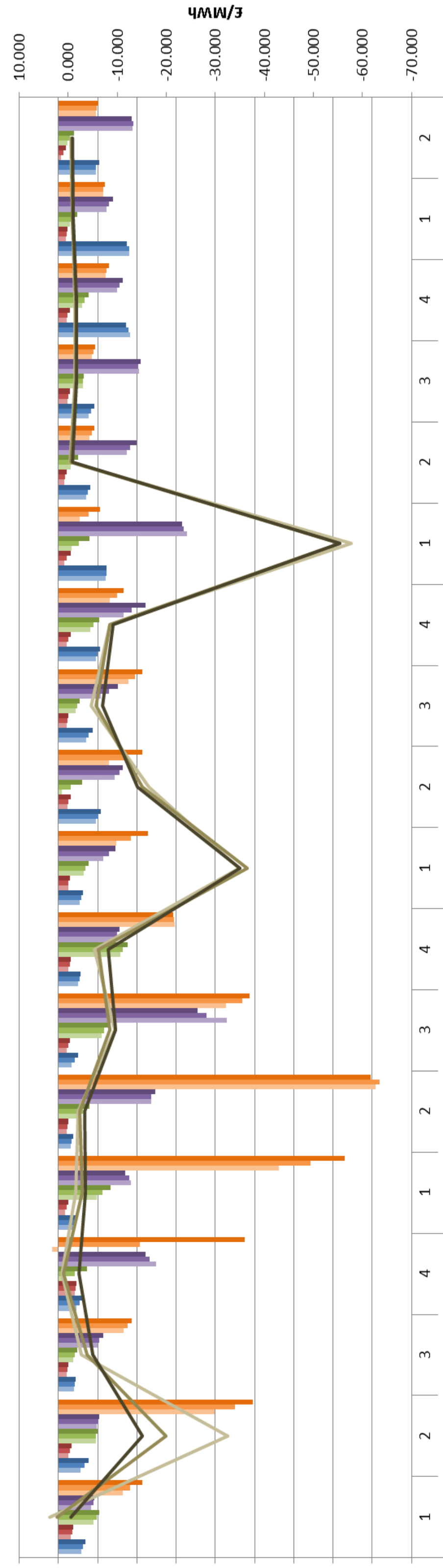


	2010 Q1	2010 Q2	2010 Q3	2010 Q4	2011 Q1	2011 Q2	2011 Q3	2011 Q4	2012 Q1	2012 Q2	2012 Q3	2012 Q4	2013 Q1	2013 Q2	2013 Q3	2013 Q4	2014 Q1	2014 Q2
I&C - 1	-0.272	-0.246	-0.158	-0.203	-0.178	-0.111	-0.128	-0.200	-0.241	-0.421	-0.296	-0.413	-0.539	-0.295	-0.318	-0.841	-0.857	-0.401
I&C - 100	-0.270	-0.287	-0.158	-0.220	-0.183	-0.117	-0.154	-0.208	-0.239	-0.428	-0.316	-0.420	-0.527	-0.307	-0.332	-0.806	-0.841	-0.388
I&C - 350	-0.277	-0.316	-0.159	-0.239	-0.178	-0.118	-0.172	-0.203	-0.225	-0.430	-0.348	-0.423	-0.485	-0.314	-0.349	-0.749	-0.790	-0.397
I&C + SME - 1	-0.139	-0.094	-0.068	-0.184	-0.056	-0.062	-0.075	-0.081	-0.089	-0.052	-0.050	-0.035	-0.010	-0.016	-0.051	-0.038	-0.055	0.028
I&C + SME - 100	-0.134	-0.094	-0.069	-0.164	-0.058	-0.060	-0.073	-0.078	-0.076	-0.049	-0.043	-0.045	-0.013	-0.013	-0.046	-0.036	-0.049	0.017
I&C + SME - 350	-0.123	-0.092	-0.065	-0.138	-0.061	-0.057	-0.070	-0.070	-0.058	-0.047	-0.035	-0.048	-0.023	-0.012	-0.043	-0.038	-0.040	0.010
Independent domestic - 1	-0.424	-0.444	-0.149	-0.066	-0.455	-0.253	-0.522	-0.737	-0.284	0.013	-0.167	-0.342	-0.102	-0.096	-0.234	-0.223	-0.099	-0.041
Independent domestic - 100	-0.451	-0.430	-0.157	-0.154	-0.519	-0.267	-0.531	-0.758	-0.290	-0.077	-0.173	-0.371	-0.174	-0.121	-0.221	-0.246	-0.119	-0.059
Independent domestic - 350	-0.454	-0.426	-0.172	-0.277	-0.595	-0.338	-0.573	-0.805	-0.301	-0.189	-0.182	-0.417	-0.260	-0.156	-0.213	-0.273	-0.150	-0.075
Renewables Aggregator - 1	-0.436	-0.515	-0.522	-1.253	-0.942	-1.190	-2.133	-0.727	-0.571	-0.729	-0.539	-0.817	-1.602	-0.832	-0.991	-0.719	-0.598	-0.918
Renewables Aggregator - 100	-0.482	-0.545	-0.543	-1.179	-0.926	-1.189	-1.870	-0.754	-0.634	-0.796	-0.633	-0.919	-1.534	-0.860	-0.975	-0.739	-0.619	-0.917
Renewables Aggregator - 350	-0.500	-0.576	-0.608	-1.152	-0.884	-1.246	-1.749	-0.783	-0.718	-0.840	-0.753	-1.079	-1.489	-0.930	-0.994	-0.777	-0.663	-0.891
SME - 1	-0.798	-1.961	-0.793	0.105	-2.779	-3.994	-2.104	-1.436	-0.704	-0.584	-0.835	-0.592	-0.205	-0.335	-0.352	-0.529	-0.530	-0.422
SME - 100	-0.873	-2.197	-0.828	-0.988	-3.169	-4.040	-2.285	-1.413	-0.875	-0.755	-0.911	-0.658	-0.289	-0.350	-0.356	-0.533	-0.521	-0.412
SME - 350	-1.006	-2.406	-0.867	-2.285	-3.585	-3.904	-2.359	-1.385	-1.055	-0.965	-0.980	-0.720	-0.400	-0.361	-0.354	-0.542	-0.516	-0.414
Renewable supplier - 1	3.742	-32.479	-2.621	1.295	-1.535	-1.929	-9.523	-5.223	-34.833	-16.371	-4.664	-8.344	-57.574	-0.383	-1.322	-1.358	-0.776	-0.452
Renewable supplier - 100	2.253	-19.824	-3.767	1.026	-2.848	-2.247	-8.355	-6.092	-36.375	-14.997	-5.602	-8.334	-55.319	-0.555	-1.430	-1.451	-0.864	-0.566
Renewable supplier - 350	-0.397	-15.130	-5.002	-2.115	-3.393	-3.353	-9.587	-8.023	-34.873	-14.064	-6.977	-8.989	-55.207	-0.845	-1.637	-1.667	-1.033	-0.701

Nb Renewable Supplier Supplier Type is measured on the secondary axis.

Figure 42

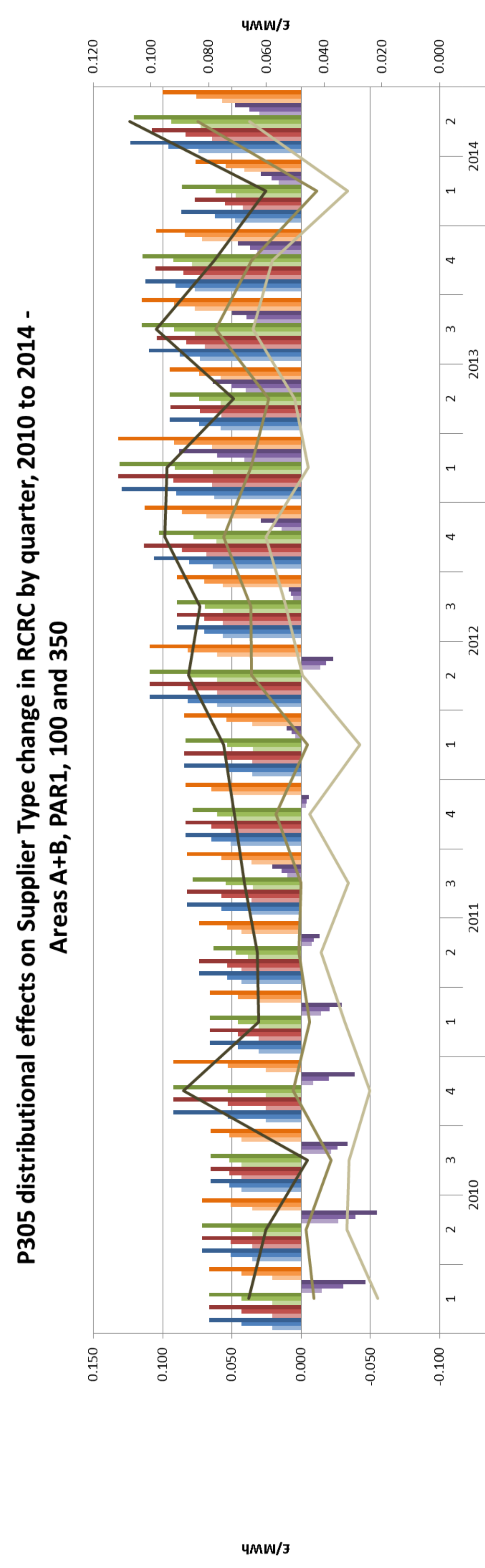
P305 distributional effects on Supplier Type change in Imbalance Cashflow by quarter, 2010 to 2014 - Areas A+B, PAR1, 100 and 350



	2010 Q1	2010 Q2	2010 Q3	2010 Q4	2011 Q1	2011 Q2	2011 Q3	2011 Q4	2012 Q1	2012 Q2	2012 Q3	2012 Q4	2013 Q1	2013 Q2	2013 Q3	2013 Q4	2014 Q1	2014 Q2
I&C - 1	-0.292	-0.281	-0.201	-0.228	-0.209	-0.154	-0.164	-0.251	-0.276	-0.481	-0.352	-0.477	-0.601	-0.353	-0.391	-0.918	-0.905	-0.475
I&C - 100	-0.313	-0.338	-0.209	-0.273	-0.229	-0.170	-0.212	-0.272	-0.292	-0.510	-0.386	-0.501	-0.617	-0.380	-0.419	-0.896	-0.903	-0.484
I&C - 350	-0.343	-0.388	-0.225	-0.331	-0.244	-0.191	-0.254	-0.287	-0.310	-0.539	-0.438	-0.529	-0.615	-0.408	-0.459	-0.862	-0.876	-0.521
I&C + SME - 1	-0.159	-0.130	-0.111	-0.210	-0.086	-0.105	-0.111	-0.131	-0.124	-0.113	-0.106	-0.103	-0.075	-0.074	-0.120	-0.111	-0.097	-0.037
I&C + SME - 100	-0.177	-0.145	-0.121	-0.217	-0.104	-0.113	-0.130	-0.143	-0.130	-0.131	-0.113	-0.131	-0.105	-0.087	-0.129	-0.121	-0.104	-0.066
I&C + SME - 350	-0.189	-0.164	-0.131	-0.231	-0.127	-0.130	-0.153	-0.153	-0.143	-0.156	-0.124	-0.162	-0.155	-0.107	-0.147	-0.143	-0.117	-0.098
Independent domestic - 1	-0.444	-0.479	-0.192	-0.092	-0.486	-0.292	-0.556	-0.785	-0.319	-0.047	-0.223	-0.403	-0.166	-0.154	-0.311	-0.301	-0.146	-0.114
Independent domestic - 100	-0.495	-0.481	-0.209	-0.207	-0.565	-0.314	-0.586	-0.818	-0.343	-0.159	-0.243	-0.448	-0.265	-0.195	-0.312	-0.339	-0.181	-0.153
Independent domestic - 350	-0.520	-0.498	-0.238	-0.370	-0.661	-0.401	-0.651	-0.883	-0.384	-0.298	-0.271	-0.519	-0.392	-0.251	-0.328	-0.388	-0.236	-0.196
Renewables Aggregator - 1	-0.420	-0.488	-0.500	-1.244	-0.928	-1.183	-2.142	-0.723	-0.575	-0.715	-0.545	-0.831	-1.643	-0.872	-1.024	-0.750	-0.614	-0.949
Renewables Aggregator - 100	-0.452	-0.506	-0.516	-1.159	-0.905	-1.180	-1.884	-0.750	-0.641	-0.778	-0.640	-0.939	-1.594	-0.910	-1.015	-0.776	-0.641	-0.955
Renewables Aggregator - 350	-0.454	-0.521	-0.574	-1.113	-0.855	-1.233	-1.769	-0.777	-0.728	-0.817	-0.762	-1.108	-1.577	-0.994	-1.044	-0.823	-0.692	-0.939
SME - 1	-0.818	-1.996	-0.836	0.080	-2.809	-4.037	-2.140	-1.486	-0.739	-0.645	-0.892	-0.660	-0.269	-0.394	-0.429	-0.600	-0.571	-0.479
SME - 100	-0.916	-2.248	-0.880	-1.041	-3.215	-4.094	-2.343	-1.478	-0.929	-0.837	-0.981	-0.744	-0.381	-0.423	-0.448	-0.617	-0.576	-0.487
SME - 350	-1.073	-2.478	-0.932	-2.377	-3.650	-3.978	-2.442	-1.468	-1.140	-1.075	-1.070	-0.833	-0.532	-0.456	-0.469	-0.646	-0.592	-0.514
Renewable supplier - 1	3.720	-32.511	-2.652	1.271	-1.568	-1.970	-9.555	-5.268	-34.861	-16.418	-4.717	-8.404	-57.619	-0.433	-1.386	-1.416	-0.808	-0.518
Renewable supplier - 100	2.210	-19.870	-3.805	0.975	-2.893	-2.295	-8.403	-6.149	-36.421	-15.063	-5.667	-8.409	-55.385	-0.614	-1.508	-1.516	-0.907	-0.650
Renewable supplier - 350	-0.463	-15.190	-5.048	-2.204	-3.455	-3.416	-9.655	-8.094	-34.948	-14.151	-7.060	-9.084	-55.302	-0.916	-1.735	-1.745	-1.093	-0.808

Nb Renewable Supplier Supplier Type is measured on the secondary axis.

Figure 43



	2010				2011				2012				2013				2014	
	1	2	3	4	1	2	3	4	1	2	3	4	1	2	3	4	1	2
I&C - 1	0.021	0.035	0.043	0.026	0.030	0.043	0.036	0.051	0.035	0.061	0.056	0.064	0.063	0.058	0.073	0.077	0.047	0.074
I&C - 100	0.043	0.051	0.052	0.053	0.046	0.053	0.057	0.065	0.054	0.082	0.070	0.081	0.090	0.073	0.087	0.090	0.062	0.096
I&C - 350	0.066	0.072	0.065	0.092	0.066	0.074	0.082	0.084	0.084	0.109	0.090	0.106	0.129	0.095	0.110	0.112	0.086	0.123
I&C + SME - 1	0.021	0.035	0.043	0.026	0.030	0.043	0.036	0.051	0.035	0.061	0.056	0.068	0.064	0.058	0.070	0.072	0.042	0.064
I&C + SME - 100	0.043	0.051	0.052	0.053	0.046	0.053	0.057	0.065	0.054	0.082	0.070	0.086	0.092	0.073	0.083	0.085	0.055	0.084
I&C + SME - 350	0.066	0.072	0.065	0.092	0.066	0.074	0.082	0.084	0.084	0.109	0.090	0.113	0.132	0.094	0.104	0.105	0.077	0.108
Independent domestic - 1	0.021	0.035	0.043	0.026	0.030	0.039	0.035	0.048	0.035	0.061	0.056	0.061	0.064	0.058	0.077	0.079	0.047	0.073
Independent domestic - 100	0.043	0.051	0.052	0.053	0.046	0.047	0.055	0.061	0.053	0.082	0.070	0.078	0.091	0.074	0.092	0.092	0.062	0.094
Independent domestic - 350	0.066	0.072	0.065	0.092	0.066	0.063	0.078	0.078	0.083	0.109	0.089	0.102	0.131	0.095	0.115	0.114	0.086	0.121
Renewables Aggregator - 1	-0.015	-0.027	-0.022	-0.009	-0.014	-0.008	0.010	-0.004	0.004	-0.014	0.006	0.014	0.041	0.040	0.033	0.031	0.016	0.030
Renewables Aggregator - 100	-0.030	-0.039	-0.026	-0.020	-0.021	-0.009	0.014	-0.004	0.007	-0.018	0.007	0.020	0.060	0.050	0.040	0.037	0.021	0.038
Renewables Aggregator - 350	-0.047	-0.055	-0.033	-0.039	-0.030	-0.013	0.021	-0.005	0.010	-0.023	0.009	0.029	0.088	0.064	0.050	0.046	0.029	0.048
SME - 1	0.021	0.035	0.043	0.026	0.030	0.043	0.036	0.051	0.035	0.061	0.056	0.068	0.064	0.058	0.077	0.071	0.041	0.057
SME - 100	0.043	0.051	0.052	0.053	0.046	0.053	0.057	0.065	0.054	0.082	0.070	0.086	0.092	0.074	0.092	0.084	0.054	0.076
SME - 350	0.066	0.072	0.065	0.092	0.066	0.074	0.082	0.084	0.084	0.109	0.090	0.113	0.132	0.095	0.115	0.105	0.076	0.100
Renewable supplier - 1	0.022	0.032	0.031	0.024	0.033	0.041	0.032	0.045	0.028	0.048	0.053	0.060	0.045	0.050	0.065	0.058	0.032	0.066
Renewable supplier - 100	0.044	0.046	0.038	0.051	0.045	0.049	0.048	0.057	0.046	0.065	0.065	0.075	0.065	0.059	0.078	0.065	0.043	0.084
Renewable supplier - 350	0.066	0.060	0.046	0.089	0.063	0.063	0.068	0.071	0.075	0.087	0.083	0.095	0.095	0.071	0.098	0.078	0.060	0.107

Nb Renewable Supplier Supplier Type is measured on the secondary axis.

Figure 44

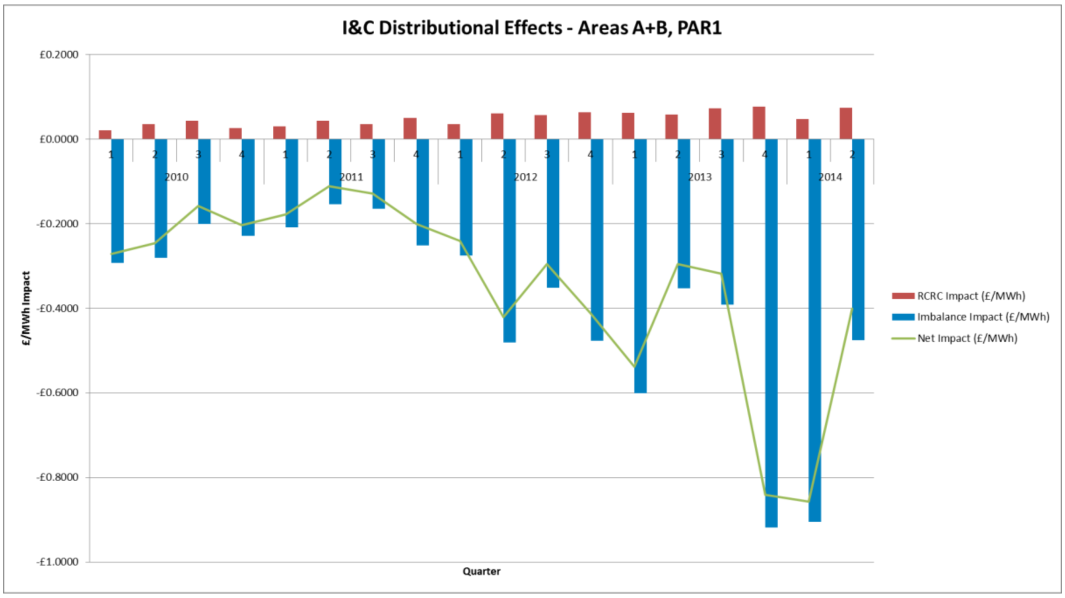


Figure 45

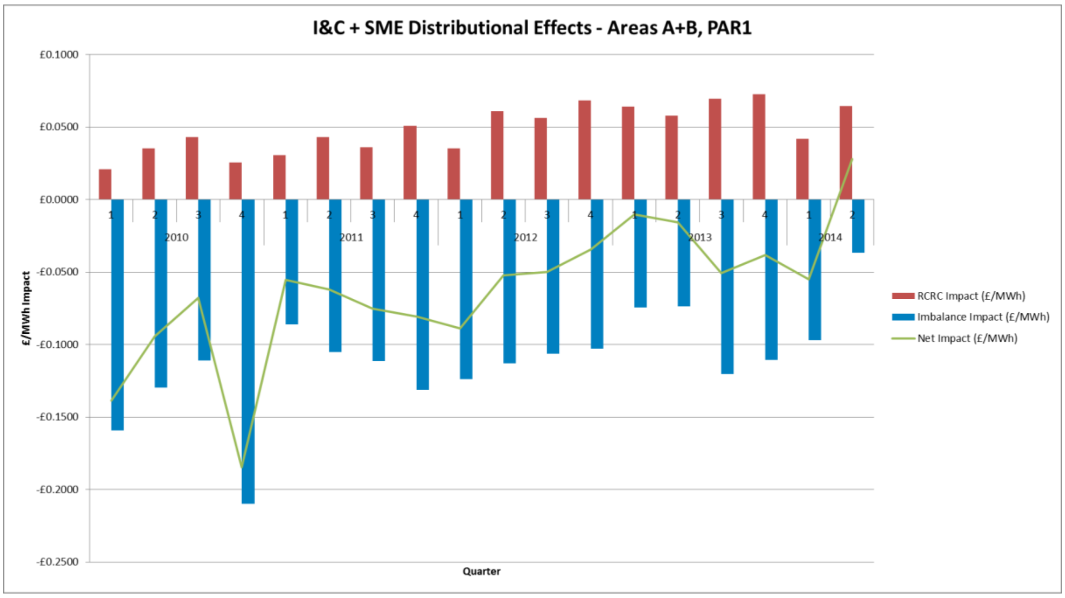


Figure 46

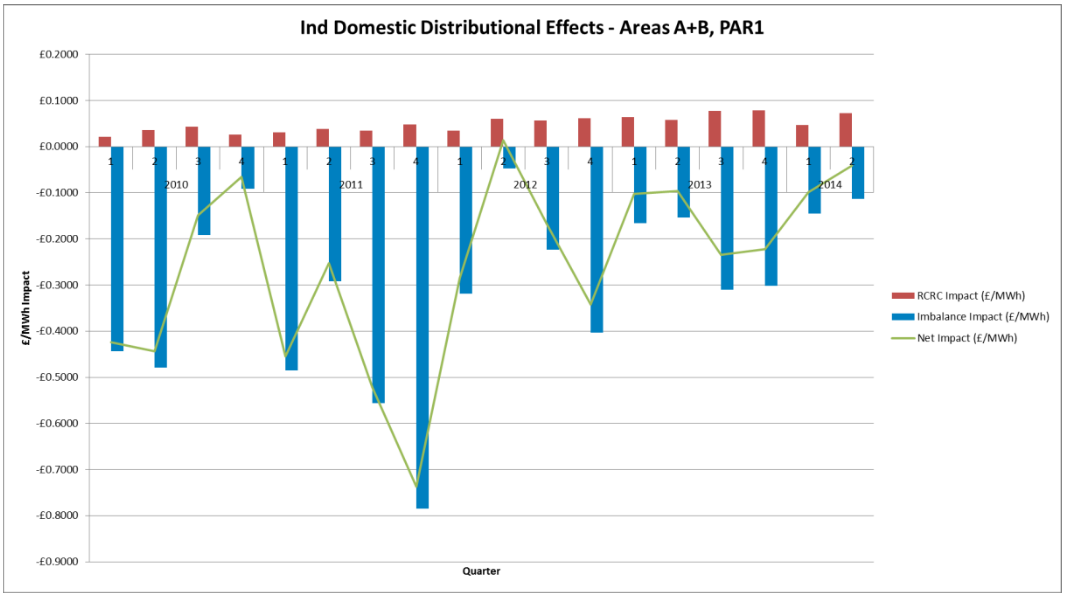


Figure 47

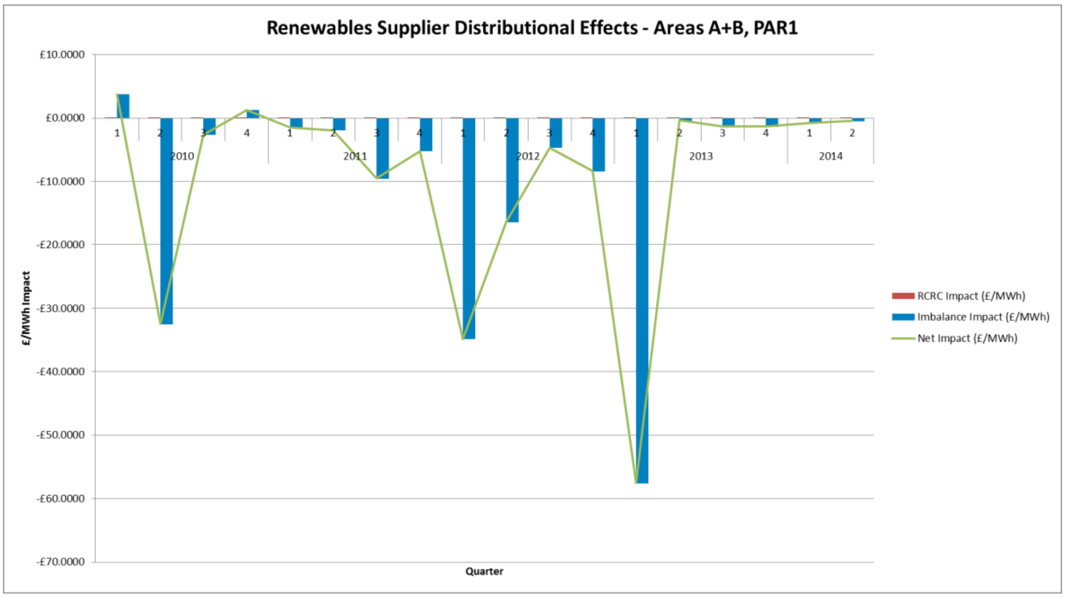


Figure 48

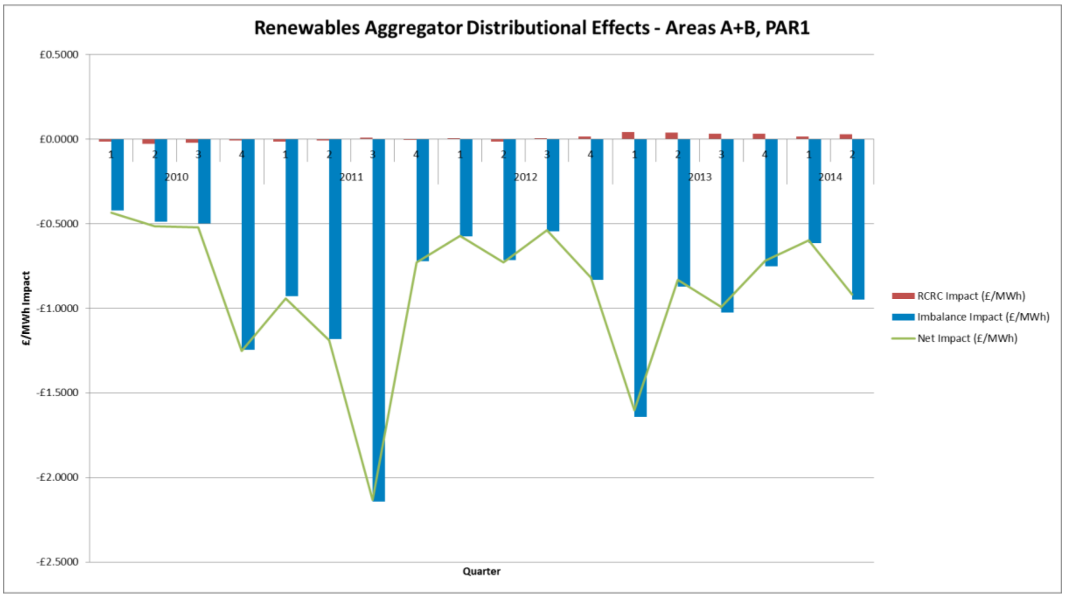


Figure 49

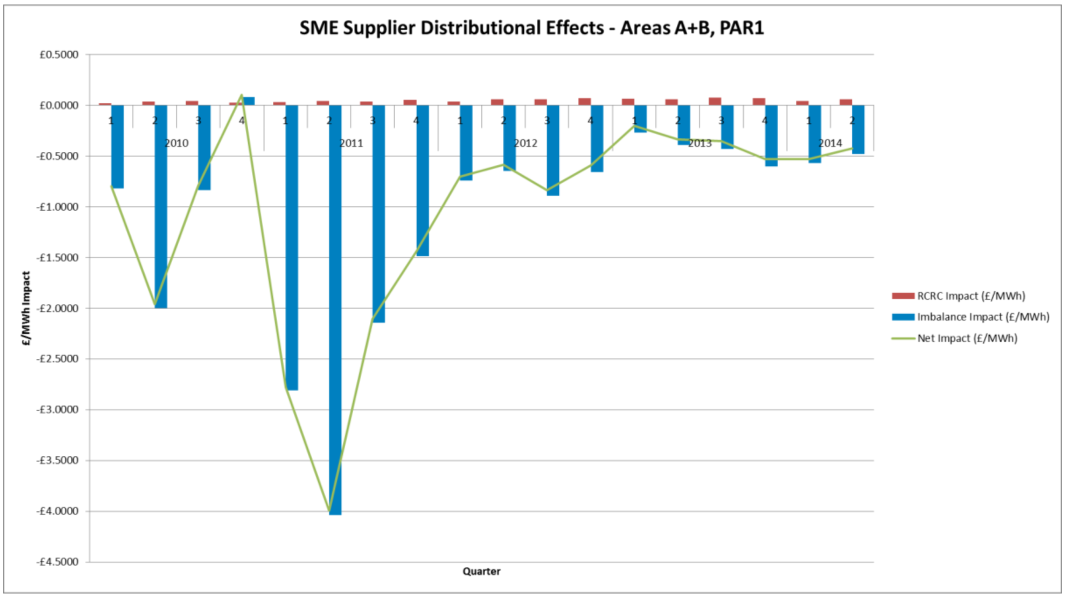


Figure 50

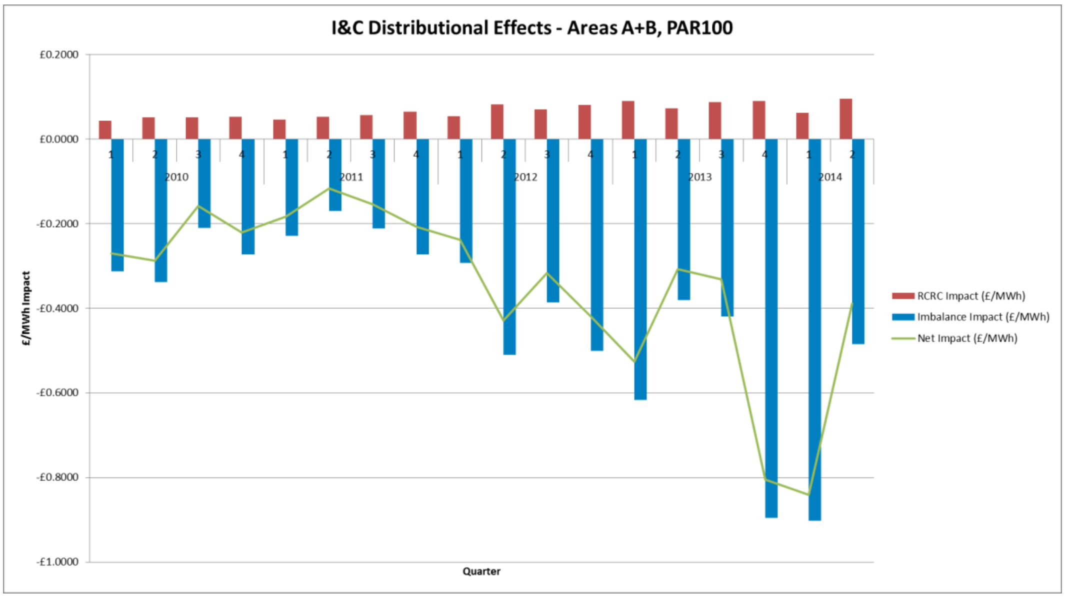


Figure 51

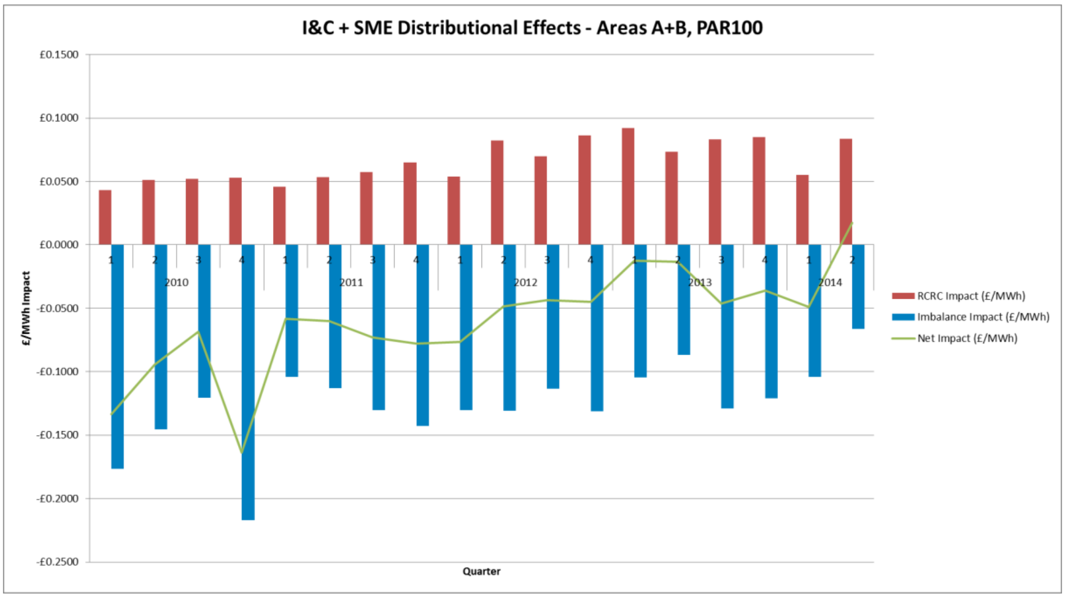


Figure 52

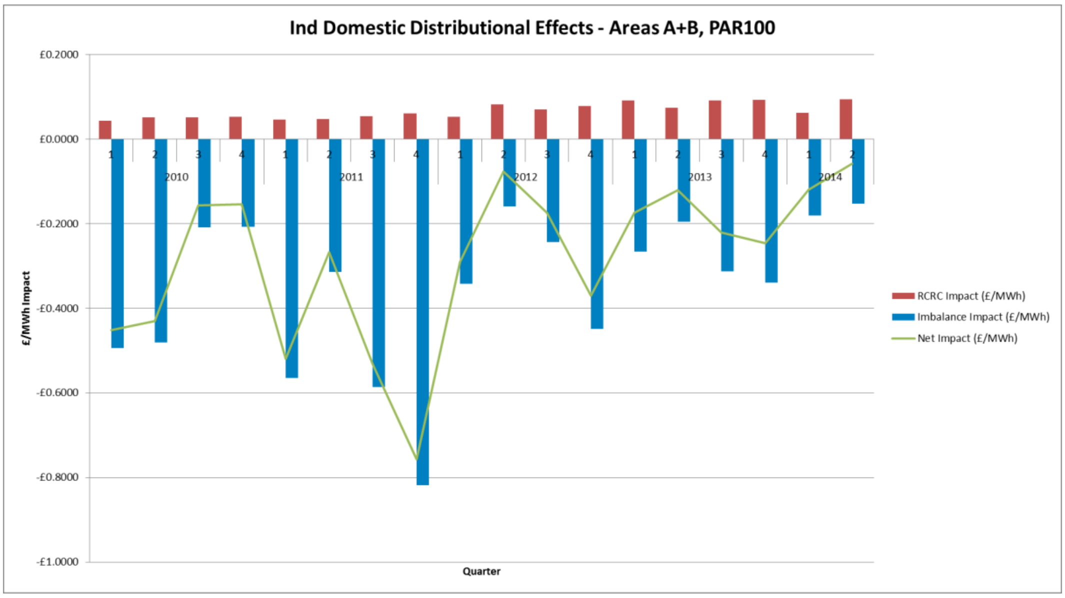


Figure 53

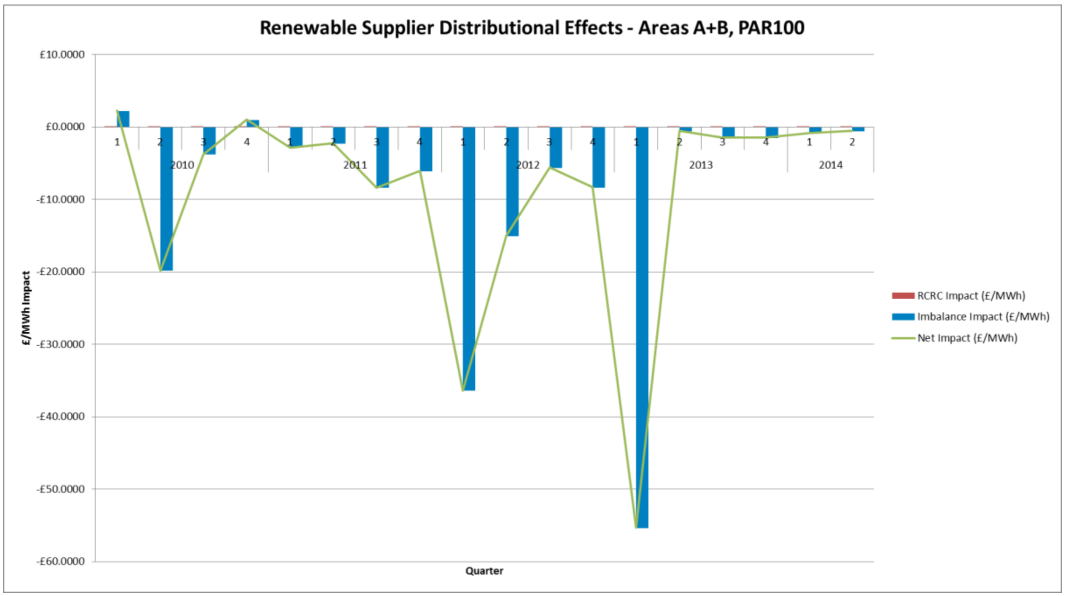


Figure 54

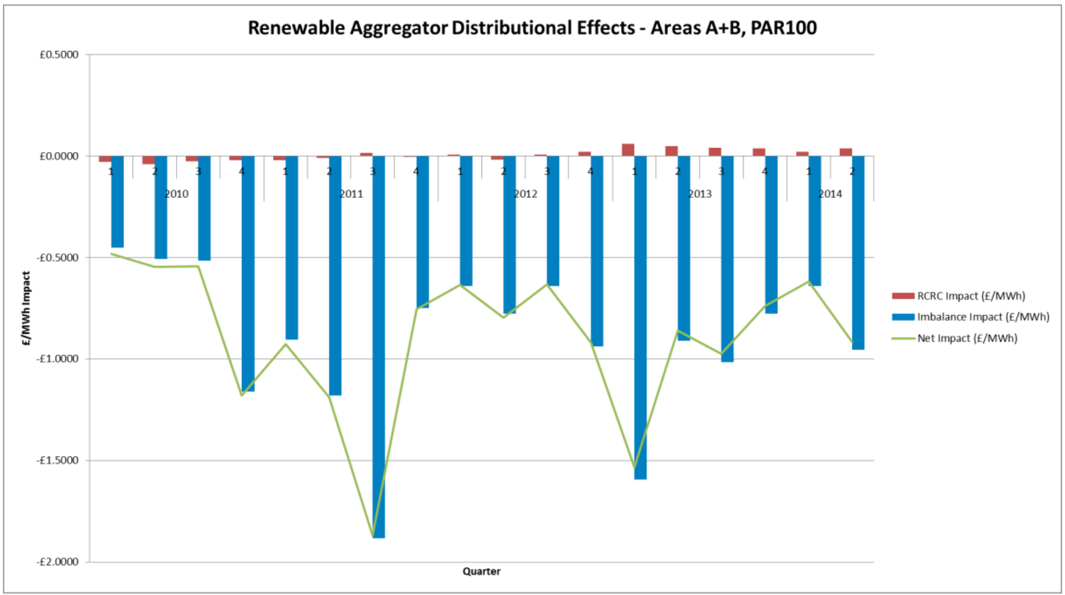


Figure 55

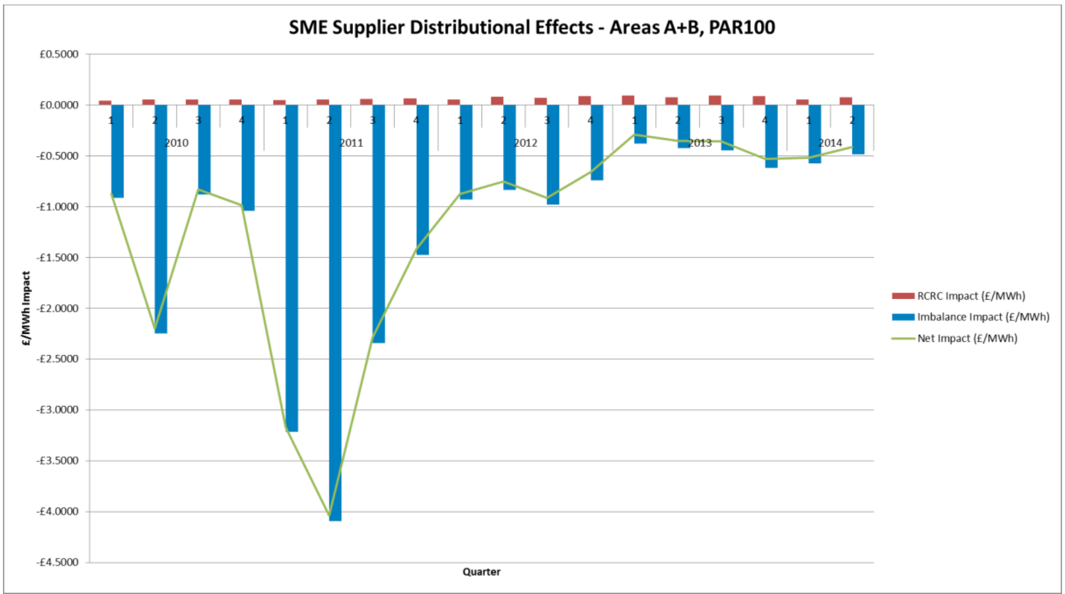


Figure 56

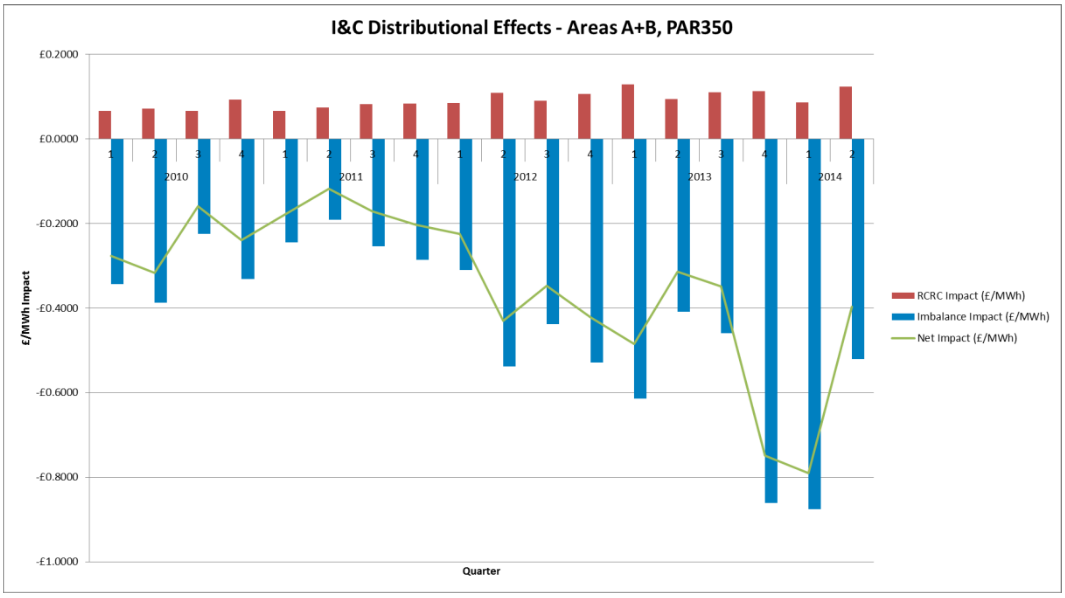


Figure 57

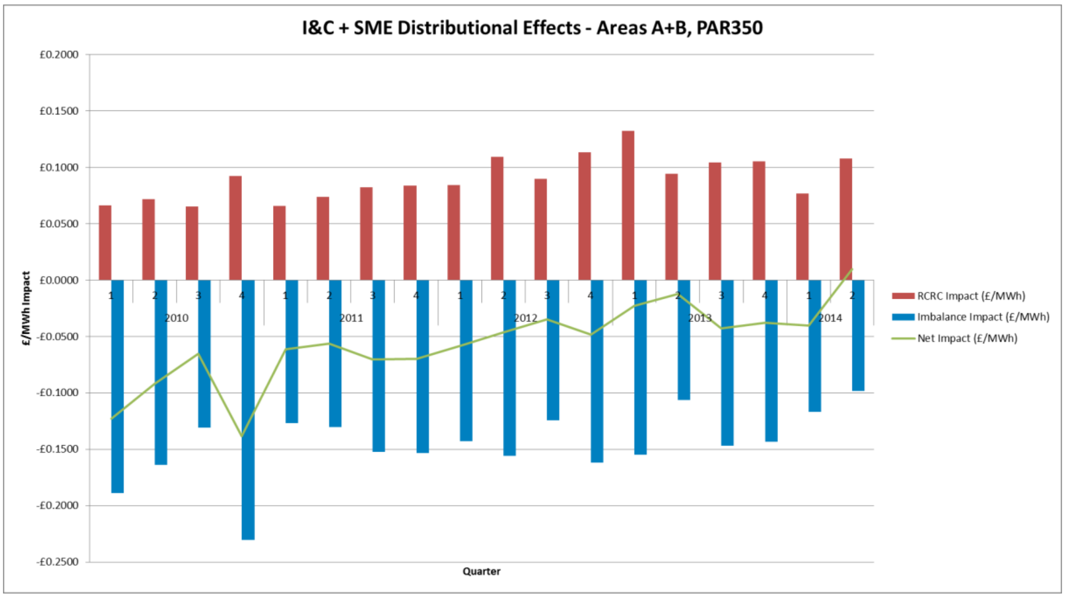


Figure 58

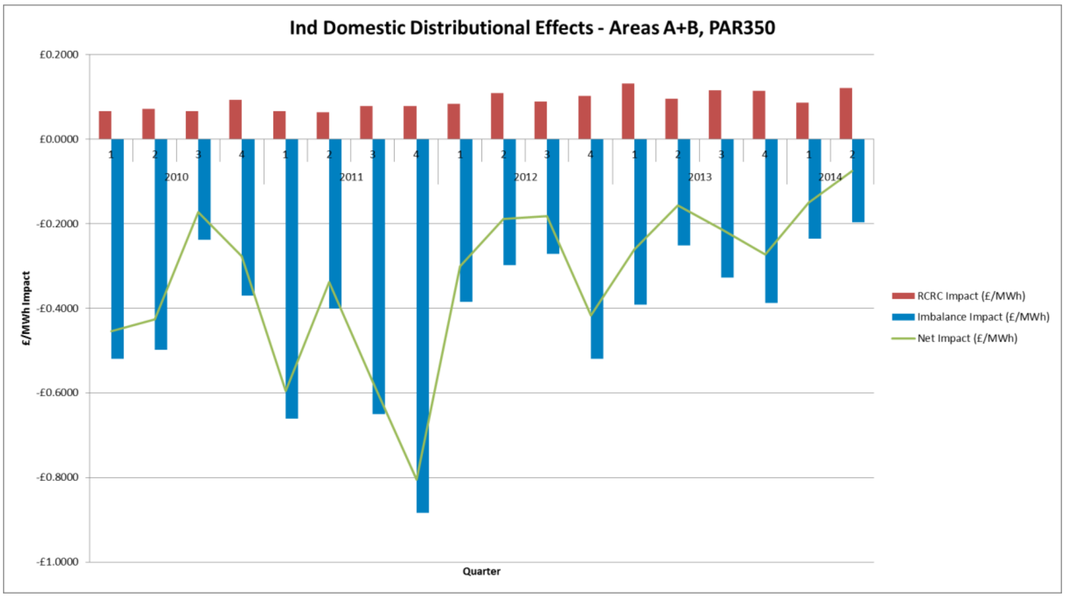


Figure 59

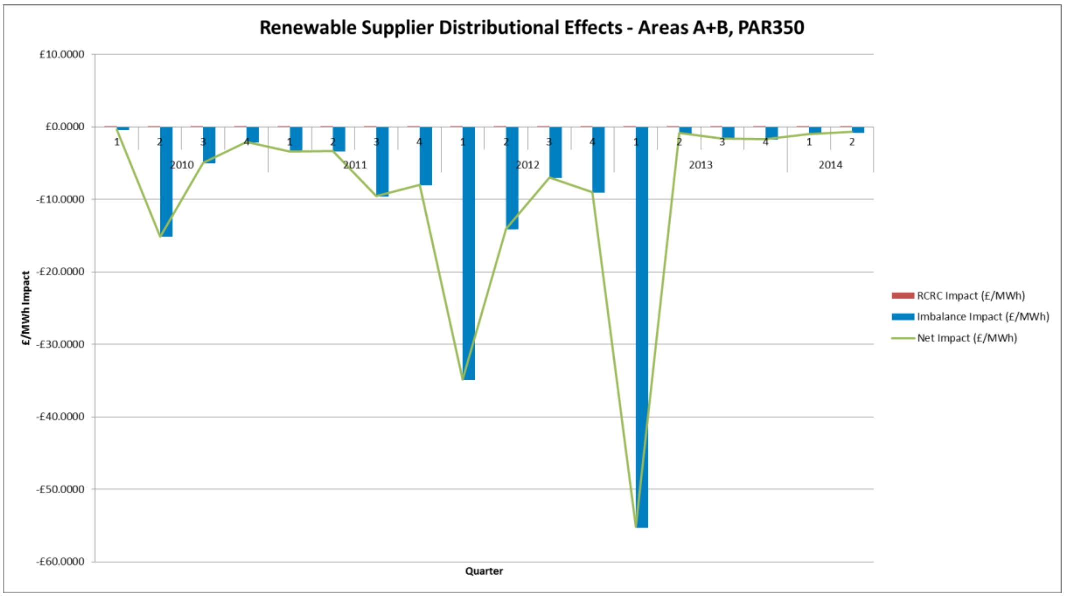


Figure 60

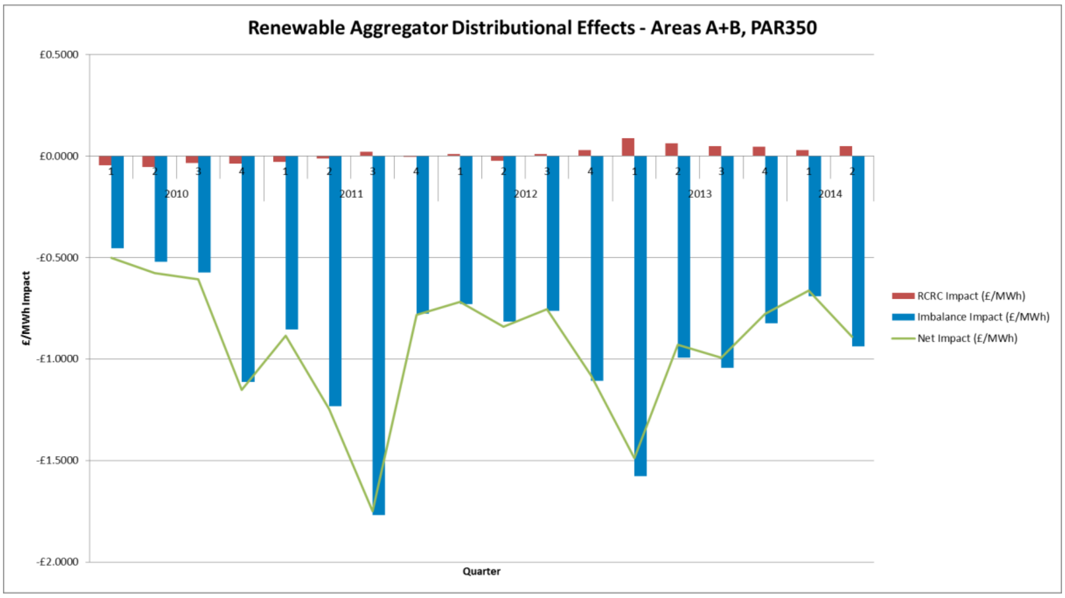
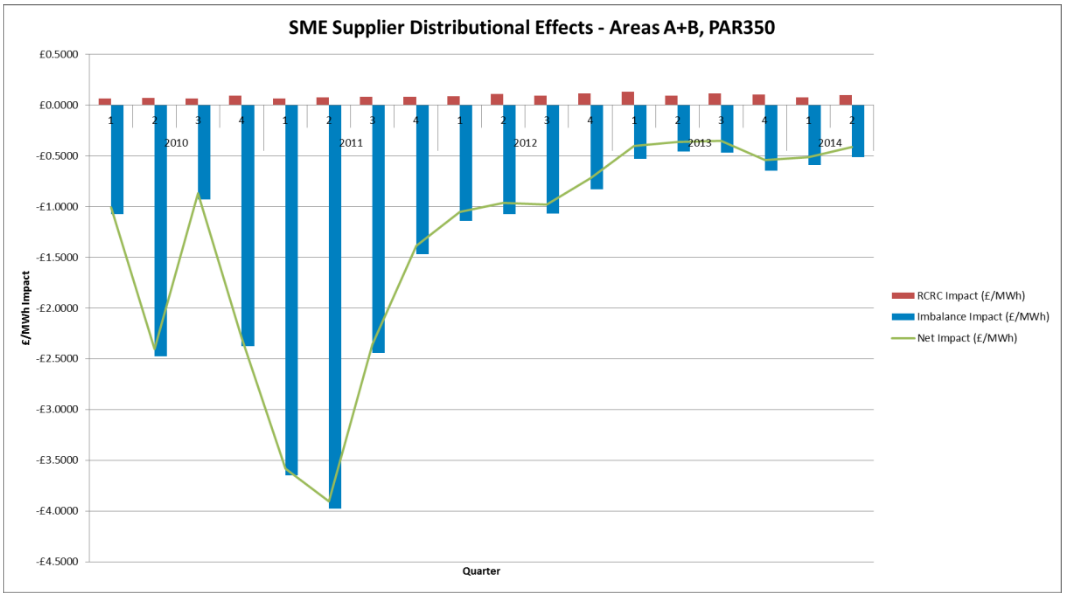
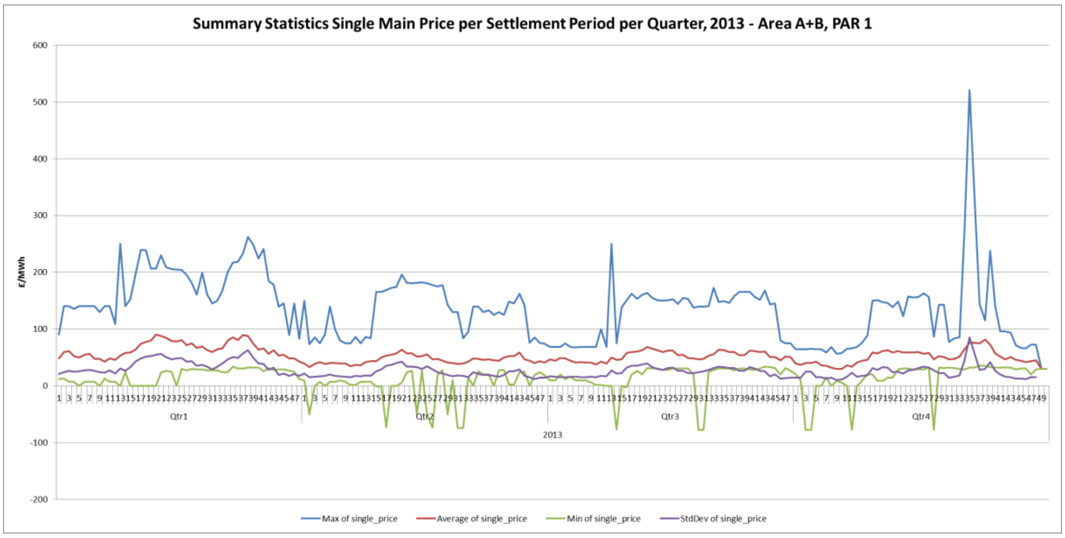


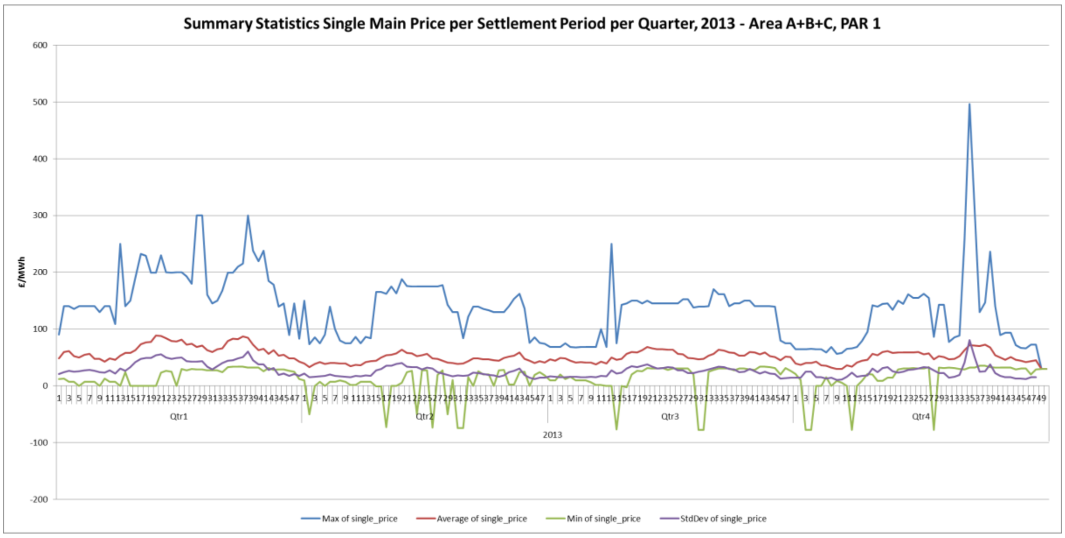
Figure 61

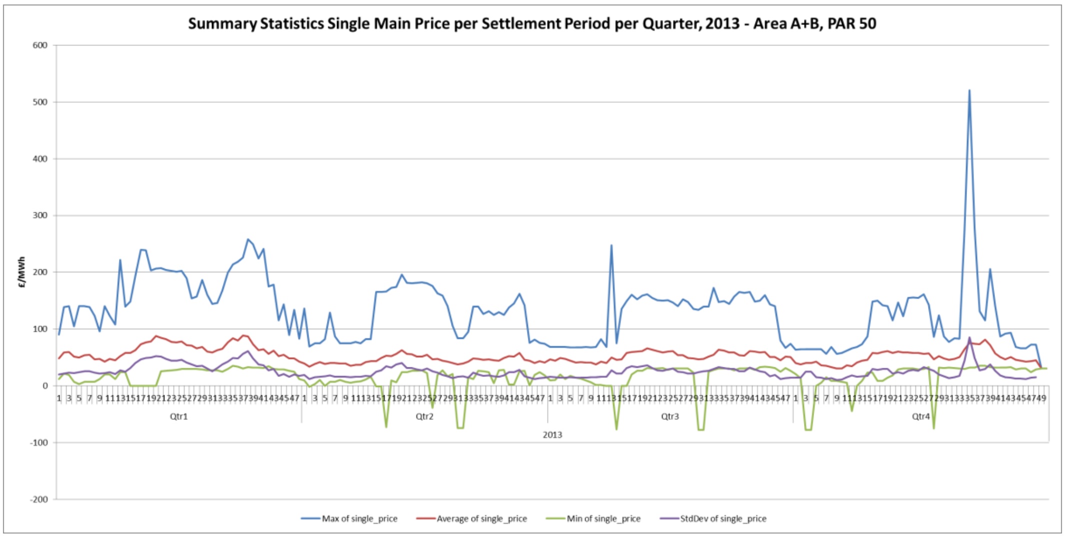


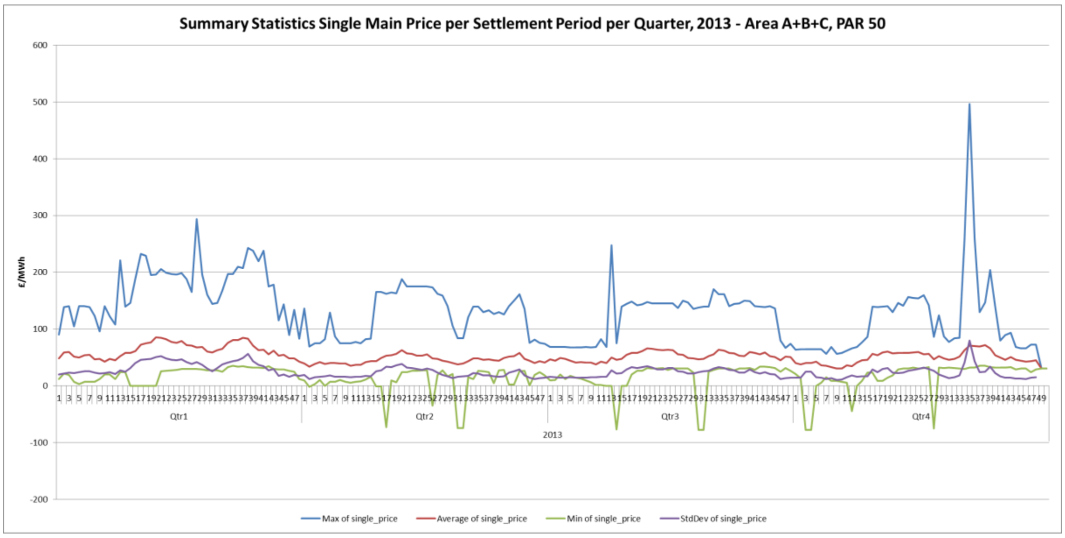
Additional charts

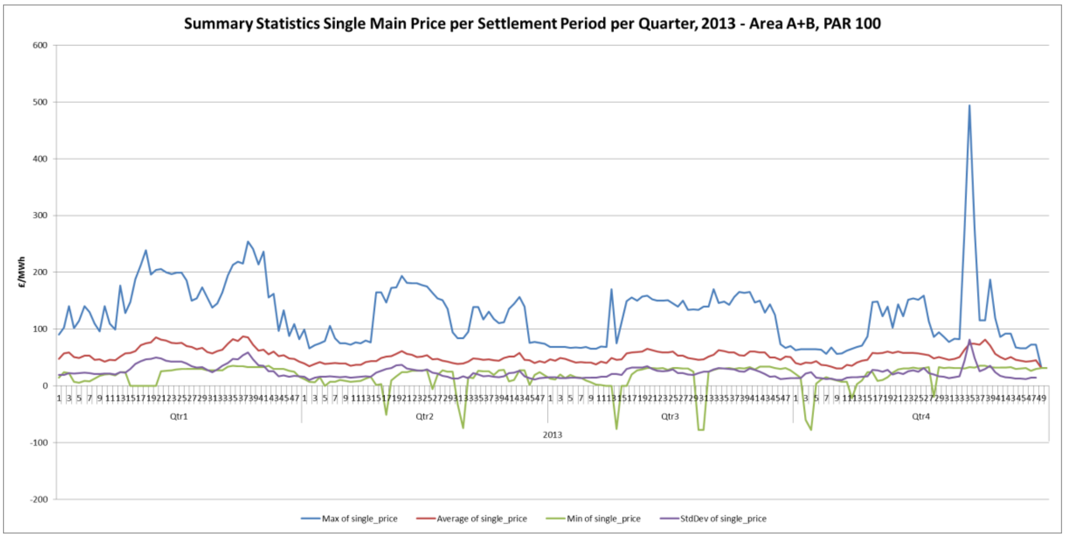
Summary Statistics

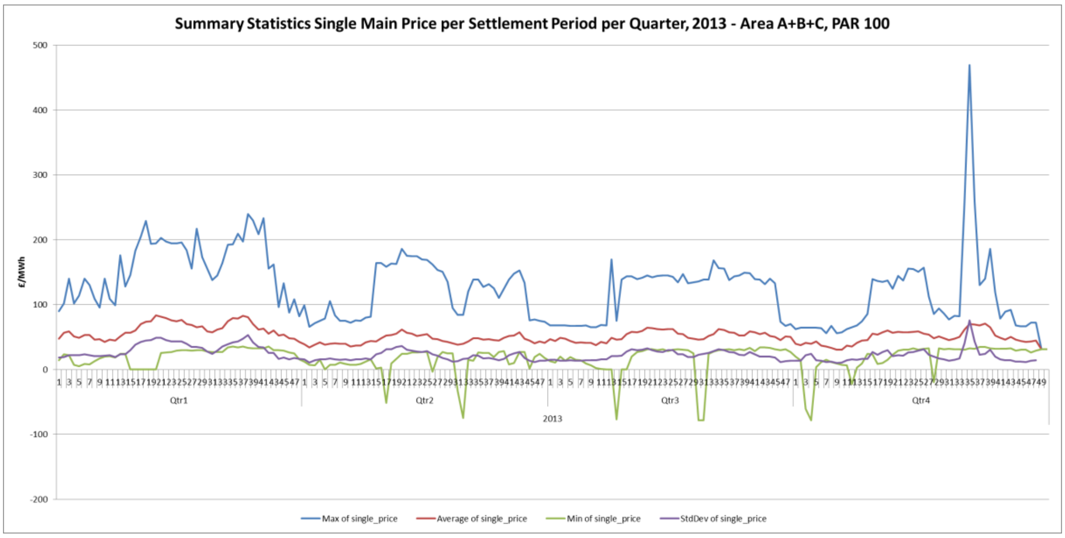


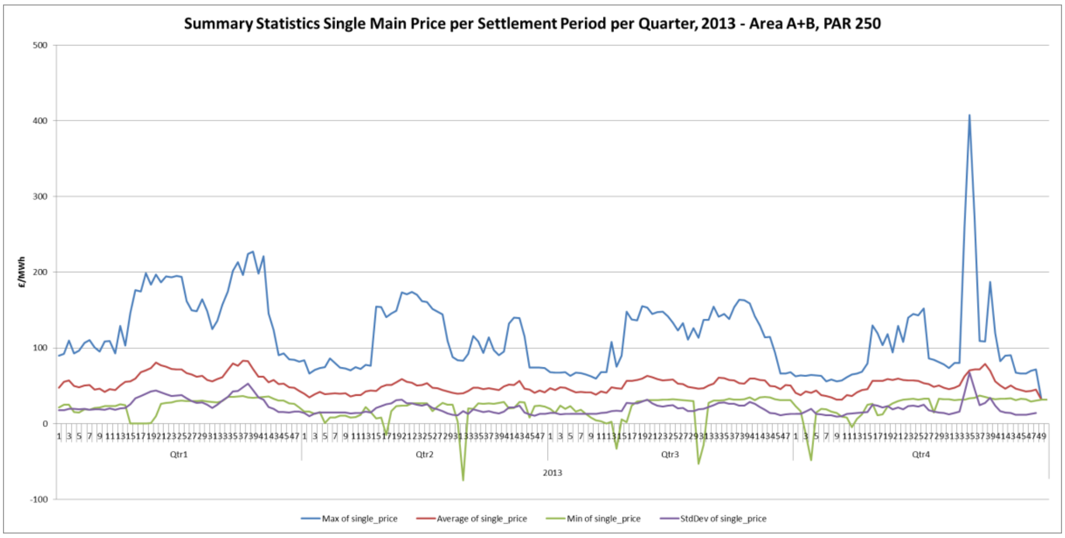


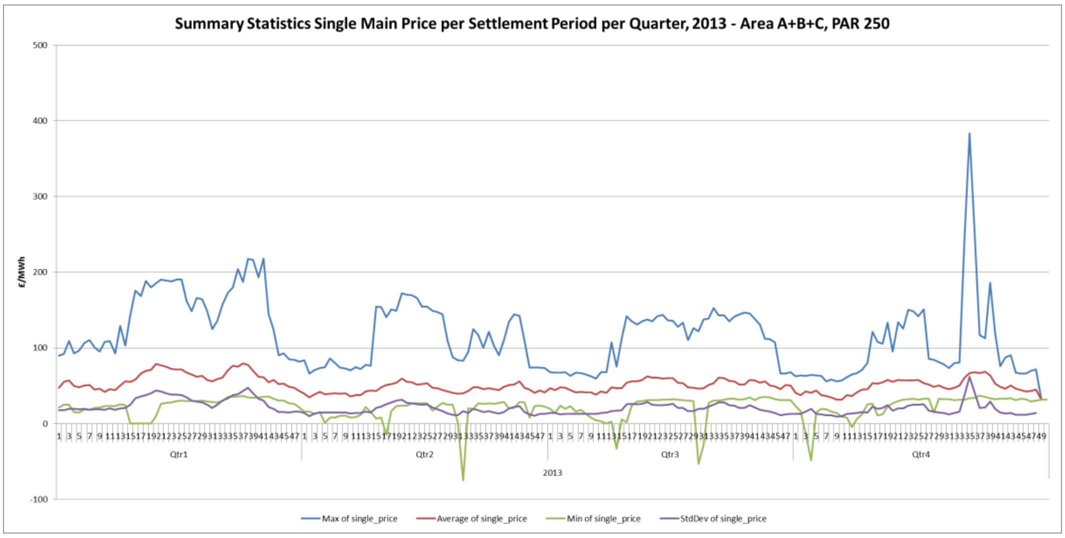


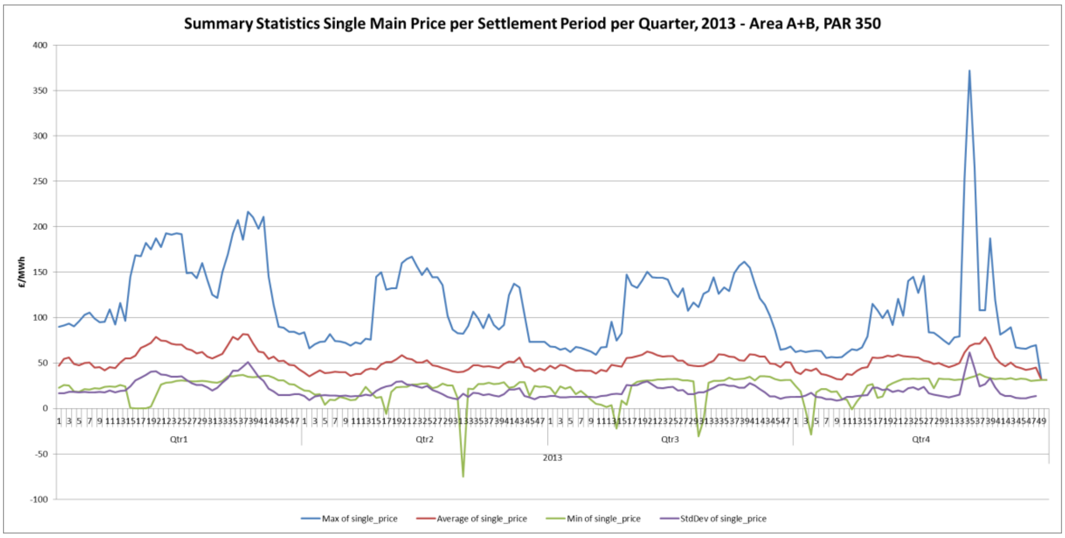

Summary Statistics Single Main Price per Settlement Period per Quarter, 2013 - Area A+B+C, PAR 50
£/MWh
Qtr1
Qtr2
Qtr3
Qtr4
2013
Max of single_price
Average of single_price
Min of single_price
StdDev of single_price

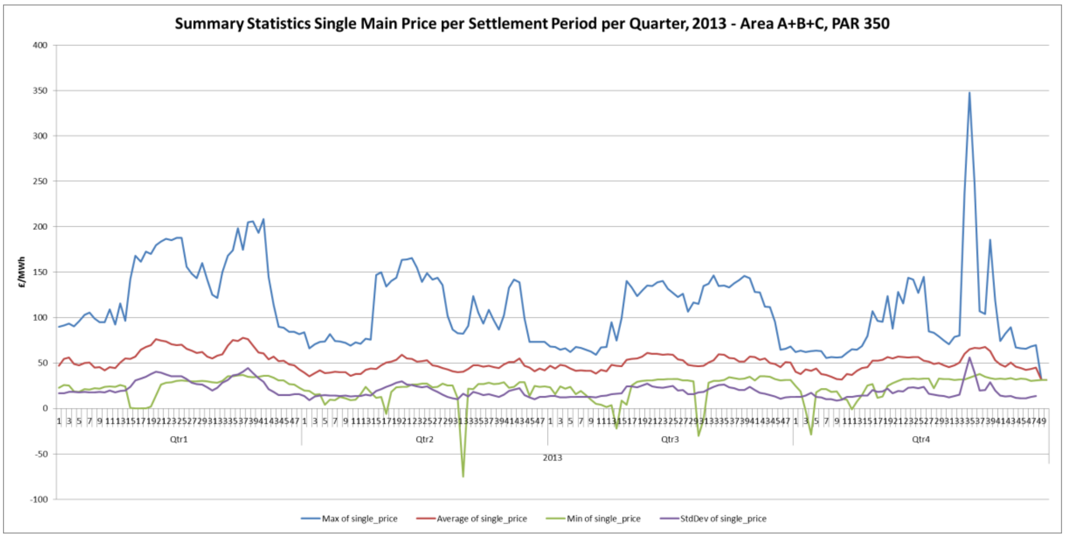

Summary Statistics Single Main Price per Settlement Period per Quarter, 2013 - Area A+B, PAR 100
£/MWh
Qtr1
Qtr2
Qtr3
Qtr4
2013
Max of single_price
Average of single_price
Min of single_price
StdDev of single_price


Summary Statistics Single Main Price per Settlement Period per Quarter, 2013 - Area A+B+C, PAR 100
£/MWh
Qtr1
Qtr2
Qtr3
Qtr4
2013
Max of single_price
Average of single_price
Min of single_price
StdDev of single_price

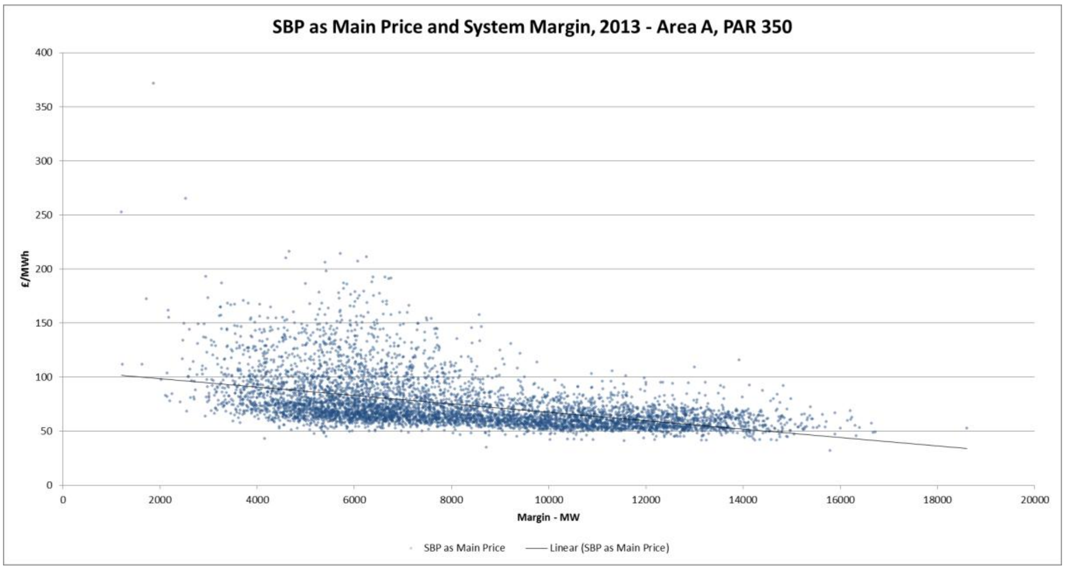

Summary Statistics Single Main Price per Settlement Period per Quarter, 2013 - Area A+B, PAR 250
£/MWh
Qtr1
Qtr2
Qtr3
Qtr4
2013
Max of single_price
Average of single_price
Min of single_price
StdDev of single_price

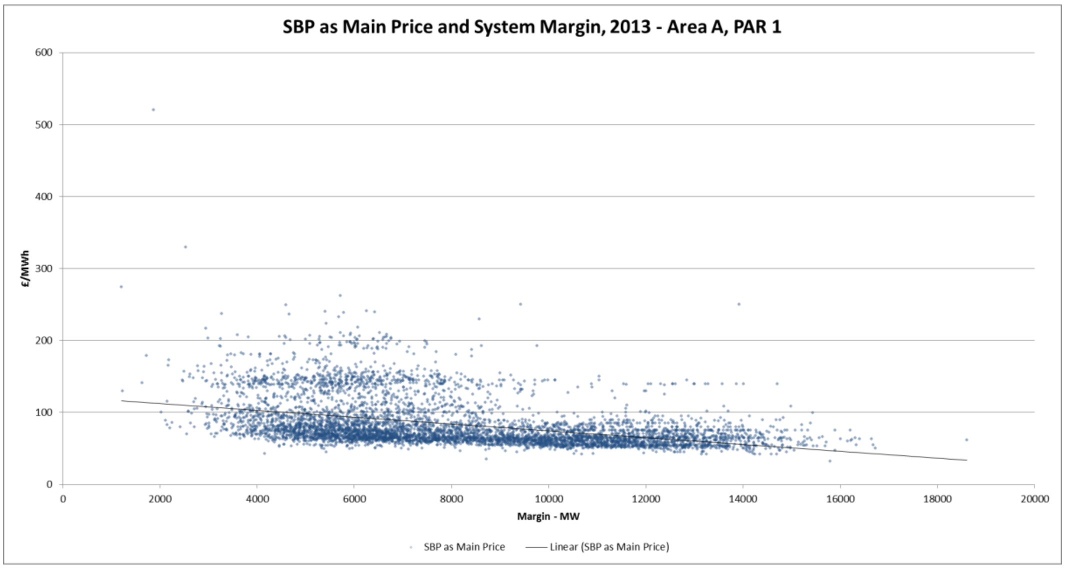

Summary Statistics Single Main Price per Settlement Period per Quarter, 2013 - Area A+B+C, PAR 250
£/MWh
Qtr1
Qtr2
Qtr3
Qtr4
2013
Max of single_price
Average of single_price
Min of single_price
StdDev of single_price

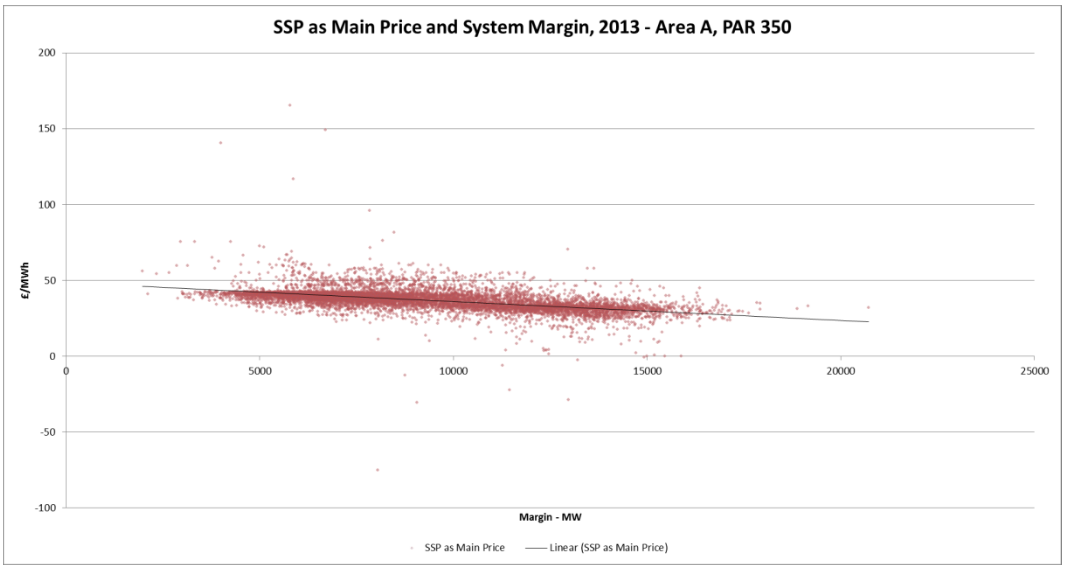

Summary Statistics Single Main Price per Settlement Period per Quarter, 2013 - Area A+B, PAR 350
£/MWh
Qtr1
Qtr2
Qtr3
Qtr4
2013
Max of single_price
Average of single_price
Min of single_price
StdDev of single_price

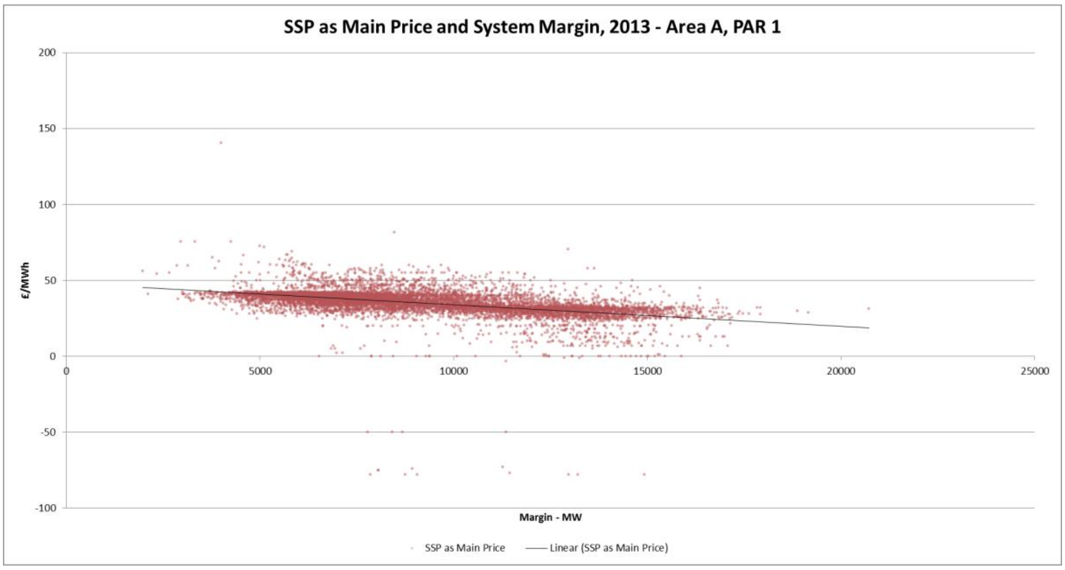


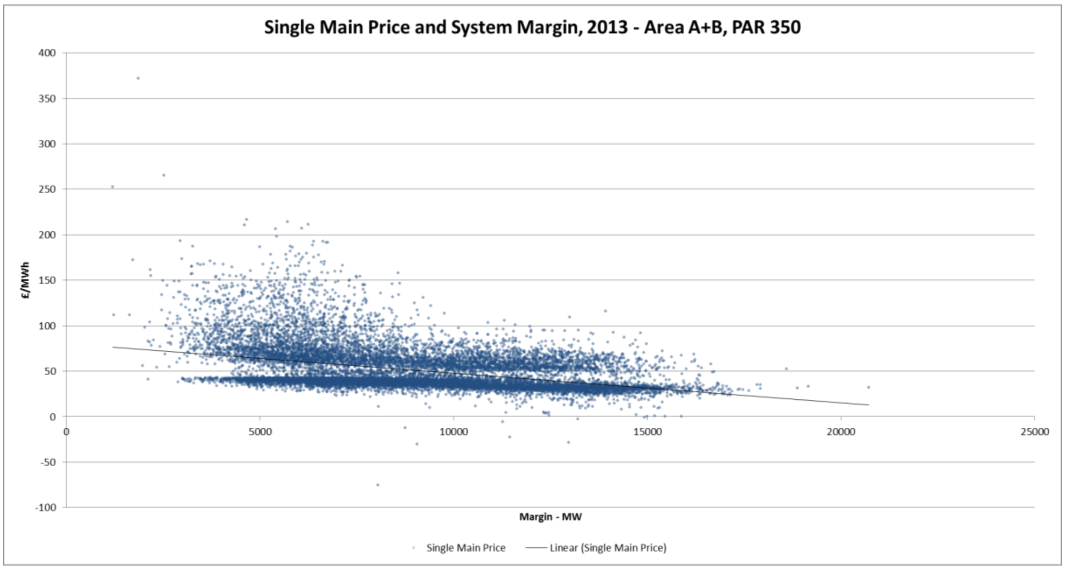
System Prices scatter by margin

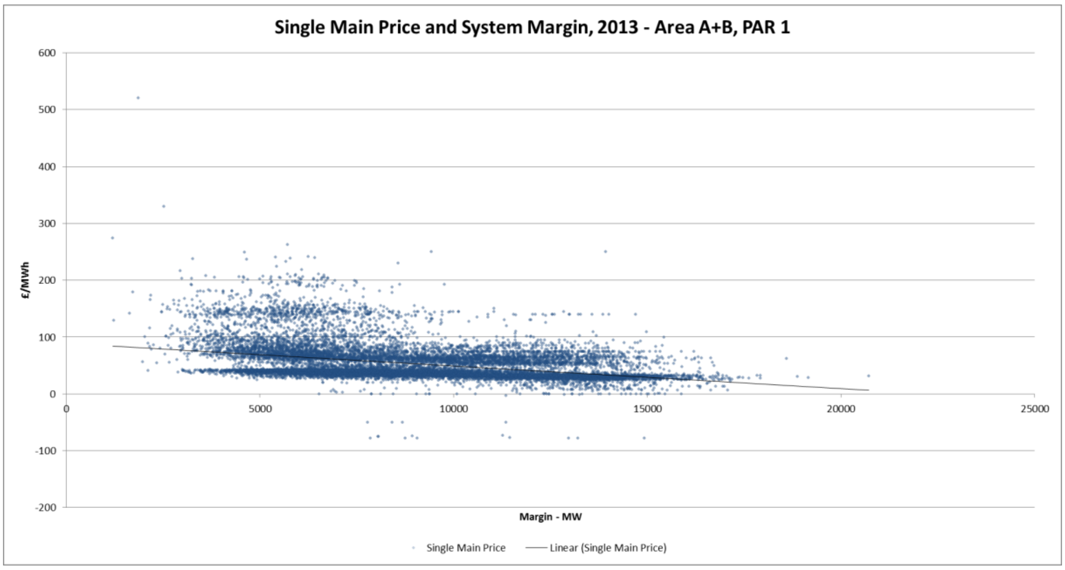


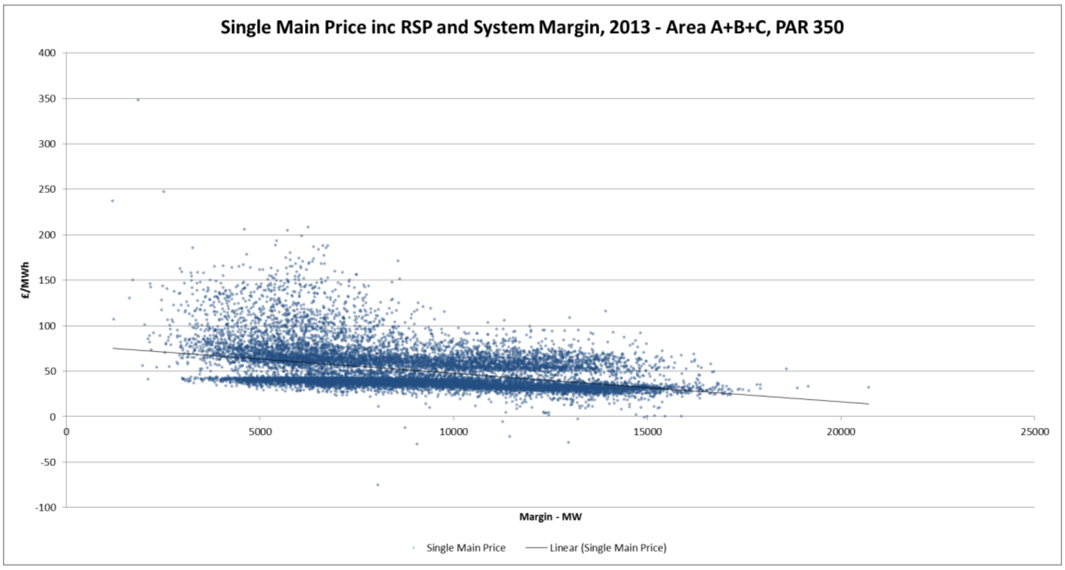


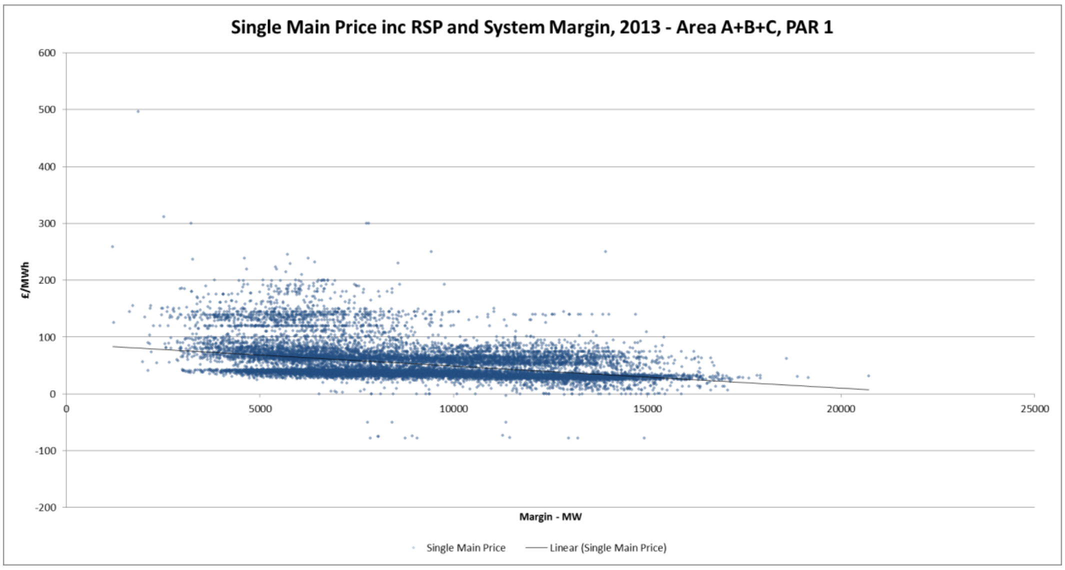

SSP as Main Price and System Margin, 2013 - Area A, PAR 350
£/MWh
Margin - MW
SSP as Main Price
Linear (SSP as Main Price)


SSP as Main Price and System Margin, 2013 - Area A, PAR 1
£/MWh
Margin - MW
SSP as Main Price
Linear (SSP as Main Price)


Single Main Price and System Margin, 2013 - Area A+B, PAR 350
£/MWh
Margin - MW
Single Main Price
Linear (Single Main Price)


Single Main Price and System Margin, 2013 - Area A+B, PAR 1
£/MWh
600
500
400
300
200
100
0
-100
-200
0
5000
10000
15000
20000
25000
Margin - MW
Single Main Price
Linear (Single Main Price)


Single Main Price inc RSP and System Margin, 2013 - Area A+B+C, PAR 350
£/MWh
400
350
300
250
200
150
100
50
0
-50
-100
0
5000
10000
15000
20000
25000
Margin - MW
Single Main Price
Linear (Single Main Price)


Single Main Price inc RSP and System Margin, 2013 - Area A+B+C, PAR 1
£/MWh
600
500
400
300
200
100
0
-100
-200
0
5000
10000
15000
20000
25000
Margin - MW
Single Main Price
Linear (Single Main Price)

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.

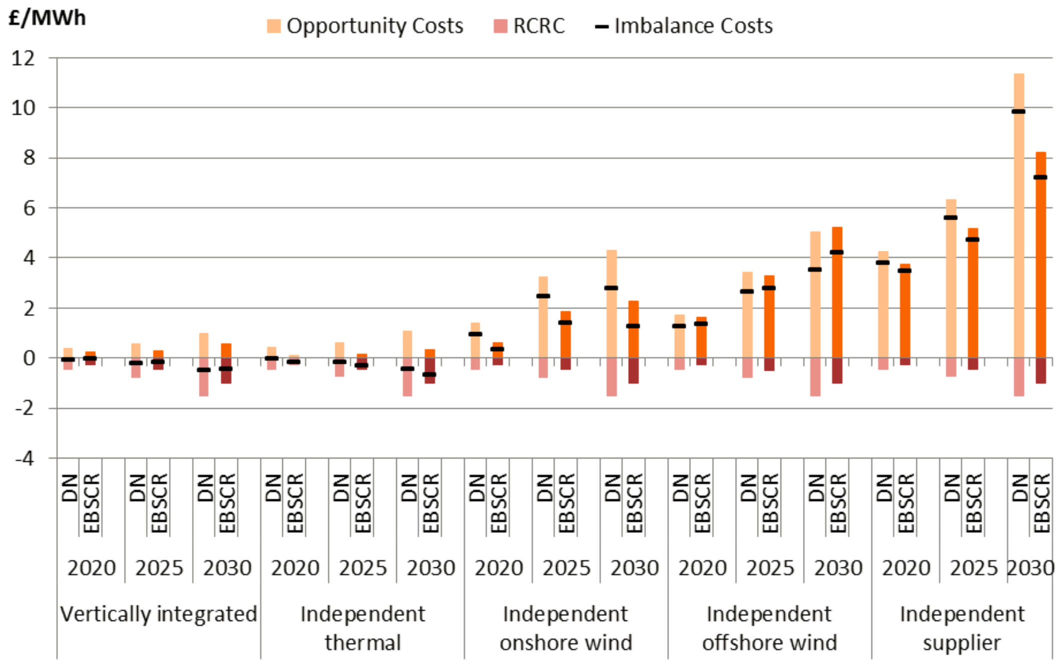
Competition

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.

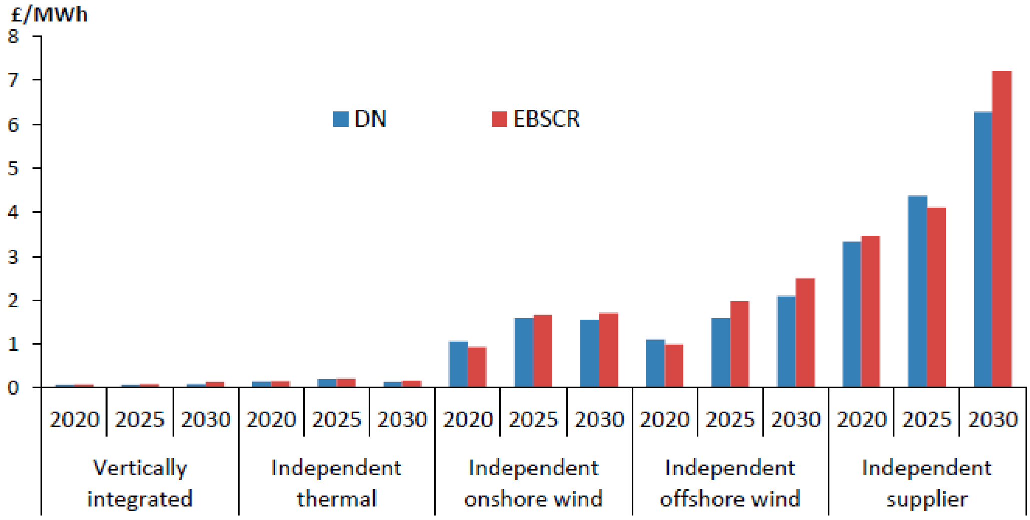
Sharper cash-out prices could be expected to disadvantage small independent Parties to the greatest extent, owing to the fact that historically they have incurred proportionally higher imbalance volumes. However, as described in Ofgem's impact assessment, small independent Parties have reducing imbalances 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 RCRC receipts). This is depicted in the figure below showing expected opportunity costs[12], RCRC and imbalance costs[13] 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.

[12] 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.
[13] 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 and Alternative Modifications, detailing the final requirements as agreed by the Proposer and the Workgroup.

Three requirements (A1, A3 and C3) have alternative versions for the Proposed Modification and the Alternative Modification. In these cases, the version applicable to the Proposed Modification has been suffixed with a 'p' (e.g. 'A1p') while the version applicable to the Alternative Modification has been suffixed with an 'a' (e.g. 'A1a'). All other requirements apply equally to both solutions.

Area A: PAR value

Requirement A1p (Proposed Modification)	
The value of PAR will be set to 50MWh.	
A1p.1	The Settlement Administration Agent (SAA) (Business Process Outsourcing (BPO) service provider) will set the value of 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.
A1p.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 A1a (Alternative Modification)	
The value of PAR will be set to 100MWh.	
A1a.1	The Settlement Administration Agent (SAA) (Business Process Outsourcing (BPO) service provider) will set the value of the PAR within central systems to 100MWh effective from the P305 Implementation Date. This value will apply to all Settlement Days from the P305 Implementation Date onwards.
A1a.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 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 A3p (Proposed Modification)	
The value of PAR will be set to 1MWh effective from 1 November 2018 (November 2018 BSC Systems Release).	
A3p.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.
A3p.2	Participants who store the value of PAR within their internal systems will need to update this value effective from 1 November 2018.

Requirement A3 (Alternative Modification)	
No further changes to the value of PAR will be made.	
A3a.1	The SAA (BPO service provider) will make no further changes to the value of PAR within central systems as part of P305.

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 NIV value is greater than zero, the Balancing Mechanism Reporting Agent (BMRA) (BPO service provider) and the SAA (BPO service provider) will calculate the 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 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.

Requirement B2	
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.

Requirement C1	
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.
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 C4.4 and C4.5) as the product of the Final LoLP value for that Settlement Period (as calculated under Requirement C2.4 or C3p.3 as applicable) 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.

Requirement C1	
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 using the 'static' LoLP function.	
C2.1	The Transmission Company will calculate the LoLP for each Settlement Period on or after the P305 Implementation Date in accordance with the 'static' LoLP function defined within the LoLP Calculation Methodology Statement established under Requirement C5.
C2.2	The Transmission Company will send to the BMRA (BPO service provider) forecasts of the de-rated margin for a given Settlement Period at the following times, 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, two and one hour(s) prior to the Settlement Period start time for each individual Settlement Period. The BMRA will publish the forecast de-rated margins on the BMRS as soon as reasonably practical after calculation but no later than 15 minutes following the calculation point at which the value was calculated.
C2.3	If the Transmission Company is unable to produce a particular forecast of de-rated margin under Requirement C2.2 (e.g. due to system outage) then that particular forecast will be deemed to be 'null'. No attempt to recalculate the forecast will be made until the next scheduled calculation point.
C2.4	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 forecast of de-rated margin for that Settlement Period produced at that time.
C2.5	If the relevant forecast of de-rated margin is not available under Requirement C2.4, the Transmission Company will use the most recent forecast of de-rated margin instead. If no forecast is available, the Transmission Company will determine the Final LoLP value to be 'null'. No attempt to recalculate the Final LoLP value will be made.

Requirement C2	
C2.6	The method for calculating the LoLP curve and the corresponding LoLP value will be contained in the Loss of Load Probability Calculation Statement established under Requirement C5. 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 production of a LoLP curve or the calculation of a LoLP value. 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 C3p (Proposed Modification)	
From 1 November 2018 (November 2018 BSC Systems Release) the Transmission Company will calculate the LoLP value for each Settlement Period using the 'dynamic' LoLP function and will stop using the 'static' function.	
C3p.1	The Transmission Company will calculate the LoLP for each Settlement Period on or after 1 November 2018 in accordance with the 'dynamic' LoLP function defined within the LoLP Calculation Methodology Statement established under Requirement C5.
C3p.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.
C3p.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.
C3p.4	If the Transmission Company is unable to calculate a particular LoLP value under Requirements C3p.2 or C3p.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.

Requirement C3p (Proposed Modification)	
C3p.5	The method for calculating a LoLP value will be contained in the Loss of Load Probability Calculation Statement established under Requirement C5. 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 C3p.2 and C3p.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.
C3p.6	From no later than 1 May 2018 the Transmission Company will begin calculating LoLP values in accordance with this Requirement C3p for information purposes. For all Settlement Periods up to and including 31 October 2018, the Final LoLP value produced under Requirement C3p.3 will not be deemed the Final LoLP value under Requirement C4.3, which will continue to use the Final LoLP value produced under Requirement C2.4, but will be published for information purposes.

Requirement C3a (Alternative Modification)	
No change to the method of calculating LoLP values will be made	
C3a.1	The Transmission Company will continue to calculate the LoLP for each Settlement Period in accordance with the 'static' LoLP function and will not switch to the 'dynamic' LoLP function.

Requirement C4	
The Transmission Company will submit the LoLP for each Settlement Period to the BMRA.	
C4.1	The Transmission Company will submit all Indicative LoLP (for the 'dynamic' function only) and Final LoLP values calculated under Requirement C2 or C3p (as applicable) 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 (for the 'dynamic' function only) 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'. Under the 'dynamic' function, 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 C4	
C4.2	The BMRA (BPO service provider) will publish all Indicative LoLP (for the 'dynamic' function only) 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. For the 'dynamic' function only, 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, or if a 'null' value is received under the 'static' function, 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.
C4.3	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.
C4.4	For the 'dynamic' function only, 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.
C4.5	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 C5	
The LoLP Calculation Statement will be established on the BSC Baseline Statement.	
C5.1	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.
C5.2	The BSC Panel will be responsible for maintaining this document. The Panel may delegate this responsibility to an appropriate Panel Committee.
C5.3	All changes to the LoLP Calculation Statement must be approved by the Authority.
C5.4	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.
C5.5	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 C4.5.

Requirement C6	
The BPA will no longer include costs associated with STOR option fees.	
C6.1	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.
C6.2	The revised calculation of the BPA is detailed in Appendix 2 of the original Impact Assessment document.
C6.3	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.

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 anticipated to be delivered; and • a System Management Action Flag (SMAF). A single notification 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;

'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	
	• 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 anticipated to be delivered 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 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 use reasonable endeavours to identify any MPANs where a demand side STOR or Demand Side Balancing Reserve (DSBR) instruction had been dispatched and an estimate of the anticipated volume to be delivered by those MPANs in that Settlement Period, and will notify these to the SVAA (BPO service provider) no later than 25WD following the cessation of the Demand Disconnection event.
D9.3	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 for each BM Unit.
D9.4	The SVAA (BPO service provider) will deduct the volume calculated for each BM Unit under Requirement D9.3 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.
D9.5	The SAA (BPO service provider) will sum the Demand Disconnection volumes calculated in D6.4 and D9.4 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
DMAT	De Minimis Acceptance Threshold
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)*
I&C	Industrial and Commercial
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

Glossary of Defined Terms	
Acronym	Definition
NDZ	Notice to Deviate from Zero
NHH	Non Half Hourly
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
SME	Small and Medium Enterprise
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

DTC Data Flows and Data Items	
Number	Name
D0036	Validated Half Hourly Advances for Inclusion in Aggregated Supplier Matrix
D0040	Aggregated Half Hour Data File
D0041	Supplier Purchase Matrix Data File
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, 19, 72	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
17, 19, 83	P305 page on the ELEXON website	https://www.elexon.co.uk/mod-proposal/p305/
17	Historic System Prices under the EBSCR Proposed Reforms page on the ELEXON Portal *(a free login account is required to view this page)*	https://www.elexonportal.co.uk/p305analysis
19	P304 page on the ELEXON website	https://www.elexon.co.uk/mod-proposal/p304/
72	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