Impact Assessment Responses

P305 'Electricity Balancing Significant Code Review Developments'

This Impact Assessment was issued on 5 September 2014, with responses invited by 26 September 2014.

Consultation Respondents

Respondent	No. of Parties/Non-Parties Represented	Role(s) Represented
Western Power Distribution	1 / 0	Distributor
TMA Data Management Ltd	0 / 1	Supplier Agent
IMServ Europe Ltd	0 / 1	Supplier Agent
APX Commodities Ltd	1 / 0	Non Physical Trader, ECVNA, MVRNA
Northern Powergrid	1 / 0	Distributor
Good Energy	1 / 0	Supplier, ECVNA, MVRNA
SmartestEnergy	1 / 0	Supplier
National Grid	1 / 0	Transmission Company
Electricity North West	1 / 0	Distributor
ScottishPower Energy management Ltd	9 / 0	Generator, Supplier, Distributor, Non Physical Trader, ECVNA, MVRNA, Supplier Agent
First Utility Limited	1 / 0	Supplier
Co-Operative Energy	1 / 0	Supplier
Siemens Operational Services	0 / 1	Supplier Agent
EDF Energy	10 / 0	Generator, Supplier, Non Physical Trader, ECVNA, MVRNA
E.ON	7 / 0	Generator, Supplier, Interconnector User, Non Physical Trader
SSE plc	10 / 1	Generator, Supplier, Distributor, Interconnector User, Supplier Agent

ELEXON

What stage is this document in the process?

01 Initial Written Assessment

02 Definition Procedure

03 Assessment Procedure

04 Report Phase

Respondent	No. of Parties/Non-Parties Represented	Role(s) Represented
Centrica	15 / 0	Generator, Supplier, Interconnector User, Non Physical Trader, ECVNA, MVRNA
G4S Utility and Outsourcing Services (UK) Limited	0 / 1	Supplier Agent

Question 1: Will P305 impact your organisation?

Responses

Respondent	Response
Western Power Distribution	**Yes** The numbers of customers, hence MPANS, that will be affected by an instruction to shed demand is unknown. We therefore believe that we would need an automated solution to enable us to guarantee meeting the obligation to report affected MPANs within the suggested 5WD timescale. Changes to our systems would be needed to recognise when Demand Reduction events take place in order to identify embedded IDNO connections impacted by the event. Further modifications will be needed to recognise the end of a Demand Reduction event and identify embedded CRA registered connections and MPANS affected by it. Reports will need to be designed allowing an as yet undefined spreadsheet to be created and despatched to Supplier Agents and Settlements as required. We would prefer a DTC flow option to notify other parties if there is potential for high numbers of MPANS to be affected.
TMA Data Management Ltd	**Yes** We will be impacted by P305 with the greatest impact with option 2 for requirement D7.
IMServ Europe Ltd	**Yes** • Change to HHDA Systems to enable sending/receiving of amended flows • Change to HHDC Systems to enable sending/receiving of amended flows • Change/Increase to Reporting, Estimations, data handling and data services and possible impact on Service Lines • There would be no difference in terms of impact between the proposed solutions • There would be less impact in our role as NHHDA as our software solution is centrally co-ordinated therefore the implementation project is of a reduced scope and scale.
APX Commodities Ltd	**No**
Northern Powergrid	**Yes** As a result of P305, Northern Powergrid will have to produce and publish a list of MPANs that have been affected. The MPAN list will

Respondent	Response
	be derived from our connectivity model and Meter Point Administration System (MPAS) via the development of established queries. The data will be subject to manual verification prior to publication, as the distribution networks operate dynamically and there are several reasons why parts of the network may not be operating in normal configuration. These include planned outages for maintenance, asset replacement, customer connection work etc. and unplanned outages arising from network faults. In such scenarios the initial list of MPANs affected by Demand Control would need to be reviewed to take into account abnormal feeding arrangements. We would expect any changes to be relatively minor and that it would be realistic for this exercise to be completed within 48-hours of compiling the initial list of affected MPANs. Northern Powergrid's Major Incident Management Plan consists of a full set of procedures and contact details contained within Codes of Practices and Section Level Procedures. We would therefore propose to develop the plan further with procedural documentation, queries, proformas, contact lists etc. so that they could be referred to in a Demand Control incident.
Good Energy	**Yes** • As a small renewable supplier we expect to be materially adversely impacted if P305 is implemented as it will cause higher imbalance charges (net of RCRC) due to the lower PAR value and associated changes, which will add to the overall supply costs for the business. • There are also additional costs as per question 2 below.
SmartestEnergy	**Yes** We anticipate imbalance costs to increase. *Confidential information provided*
National Grid	**Yes** The precision of the solution impacts that we are able to provide is constrained by the current level of detail provided for the proposed solutions. We do not anticipate any impacts to our systems or processes as a result of Areas A (PAR value) or B (Single imbalance price). However changes will be required to deliver solutions for the requirements under Area C (Reserve Scarcity Pricing) and Area D (Value of Lost Load pricing for Demand Control actions). A summary of the changes required under C and D are provided below. **Area C Reserve Scarcity Pricing** ***STOR Actions*** Changes to existing and/or new data submissions to the BMRA will

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	be necessary to facilitate requirement C1 for the notification of instructed BM and non-BM STOR actions. In the case of accepted BM STOR actions, a system change will be required to identify accepted actions as contractual STOR. In the case of non-BM STOR actions, system changes will be required to provide details for each instructed action, including the utilisation price. ***LOLP & Indicative LOLP Production and Submission*** Changes to systems and processes will be required to facilitate our production and submission of the final Loss of Load Probability (LOLP), indicative LOLPs and any associated data under requirements C2 and C3. The full requirements are yet to be agreed by the Workgroup for the LOLP specification which will have considerable bearing on the scope and complications of the implementation impacts. The Market Operational Data Interface System (MODIS) performs a similar reporting function to the broad requirements as they are written in the Impact Assessment. The extent to which LOLP functionality can be incorporated into MODIS will depend on: the exact requirements; whether any new data is needed; and the source systems for the data inputs. In particular, production and storage of any new data items associated with the LOLP (e.g. generator reliability) will require solutions which may range in complexity. The more we are able to re-use existing system functionality, the simpler the solution should be, and the lower will be the anticipated costs and lead times. Among open LOLP questions to be determined, the calculation method and input parameters are under discussion. Additionally, as well as determination of the calculation for the LOLP, a series of validation and defaulting rules will need to be determined and agreed that apply for input parameters in the event of missing or invalid data (e.g. If a wind forecast fails what should be the defaulting rule for the LOLP / RSP / cash-out price calculations? What is the tolerance level for missing or invalid data inputs before the RSP is set to a default value?) Please note we do not have the appropriate data to be able to calculate indicative LOLPs more than 24 hours[1] in advance of the relevant Settlement Period, hence we are unable to facilitate this part of the requirement under C2.2. The longer lead times suggested by the Workgroup would require additional data submissions from BM Participants under BC1 of the Grid Code (notably MELs, PNs and other dynamic parameters). Longer submissions of these data items may have an impact on the Electricity Balancing System (EBS) in terms of validation rules,

[1] In accordance with BC1 within the Grid Code, BM units are currently required to submit PN submissions for the following operational day (05:00 to 05:00) by 11:00am. Therefore, it will not always be possible to create a 24 hour rolling indicative LOLP at each settlement period as earlier periods (e.g. 05:00 – 05:30 next day) will be published less than 24 hours in advance. The opposite is naturally true for later periods (e.g. 04:30 – 05:00 in two days' time) which will be published more than 24 hours in advance.

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	process times and data storage. We therefore suggest that these requirements are de-scoped from this modification proposal and if required form the basis of a separate modification. ***Calculation of the Buy Price Adjuster (BPA)*** System changes will be required to amend the calculation of the BPA to remove STOR costs. **Area D Value of Lost Load Pricing for Demand Control Actions** ***Notification of a Demand Control Event*** System changes will be required to facilitate the new information requirements for notification of demand control events and details under Requirement D2. Within the current timescales a manual solution for the submission of notifications is the most feasible, particularly since a solution that involved automation of a demand control instruction and notification would require agreement with LDSOs. Control Room processes and procedures will require amending to provide for these further information feeds. Please note, information under D2 will be notified on a best endeavours basis, however the focus of the Control Room staff during periods where Demand Control actions are necessary will be on maintaining a secure and stable Transmission System. In the event of an Automatic Low Frequency Demand Disconnection (LFDD) it will be difficult to determine impacted LDSO(s) within short timescales. The Workgroup has requested that notifications of these events are 'system flagged'. Therefore to enable a timely submission of an LFDD event notification we suggest that we do not seek to populate the impacted LDSO field. ***Identification of MPANs subject to Demand-Side Instructions (Requirement D8.2)*** In the case of DSBR, service providers are able to offer demand response volume over a number of MPANs only a fraction of which may deliver the tendered volume from the DSBR unit. Therefore, in the case of DSBR being instructed, initially we would not know which MPANs had been dispatched only the total volume instructed to a given counterparty by DSBR unit. We would depend on Data Collector data accuracy and timings to be able to identify the impacted MPANs, the target accuracy for Half-hourly Data Collectors is 99% for the SF run 16 days after dispatch. In the case of non-BM STOR, we access unit specific or aggregated metering at the STOR site level (which could be made up of multiple sub sites) and not the MPANs; however we are able to provide the data associated with BM STOR. An additional complication for non-BM STOR is that sub-sites can be reallocated to a STOR unit up to 25 times a year.

Respondent	Response
	Hence provision of DSBR MPANs will be subject to Data Collector timescales and currently we would be unable to provide non-BM STOR MPANs for D8.2.
Electricity North West	**Yes** We will need to produce scripts to run against a number of IT systems to provide the level of reports required. We would then need to produce individual reports for each data aggregator and send the report to them as well as sending the full report to the SVAA. Also, we will need to inform the CDCA of any embedded BM unit that was subject to such a disconnection and for the period of time that it occurred. This would only be known during the event in question so reactive measures would need to be put in place between departments to trigger the action.
ScottishPower Energy management Ltd	**Yes** P305 will not significantly impact our systems or internal processes but will require a re-consideration and re-evaluation of the risks of more marginal imbalance pricing on our generation and supply businesses.
First Utility Limited	**Yes** New systems will be needed to manage new data flows such as LOLP and to make use of this information in the formulation of hedging strategies. These will need to be developed, tested and proved. If the proposed solution places additional un-anticipated burdens or risks on First Utility then we may need to adjust our trading, operational and sales strategies. The impact cannot be assessed until after the impact analysis on the proposed solution has been performed. We expect P305 to change price distributions and liquidity in the wholesale forward market and we identify these as areas of specific concern in which the distributional impact on different market participant types will need to be closely examined.
Co-Operative Energy	**Yes** The implementation of P305 is likely to have a significant effect on the ability of Co-Operative Energy to effectively manage its imbalance risk in relation to its market position. As a domestic supplier, Co-Operative Energy is unlikely to ever find itself in a situation where it has no exposure at all to imbalance due to the near impossibility of estimating the likely usage of its domestic customer portfolio with total accuracy. While we think that it is unlikely that we will incur any significant additional internal costs in terms of dealing with the changes described in P305, we will face significantly increased cost exposure to cash-out. This will potentially affect the ability of smaller suppliers to compete on a level playing

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	field as, unlike the large vertically integrated suppliers, they do not hold generation assets within their portfolio to effectively hedge their near-term imbalance risk. We are also of the view that the proposed reductions to PAR of 50MWh in November 2015 and then 1MWh prior to Winter 2018 will create a strong incentive to hold generation back from the wider market for this purpose, thus potentially making imbalance prices higher and more volatile than they would otherwise have been. However, we would like to register our support for the proposed introduction of single-priced cash-out arrangements as we believe this will alleviate the assymetric imbalance risk currently faced by market participants under the current dual-priced cash-out arrangements. It should also remove a significant proportion of the incentive for vertical integration although we believe that this incentive will reassert itself irrespective of whether cash-out arrangements are dual- or single-priced should PAR be reduced to 50MWh or 1MWh, simply because PARs of this level have the potential to result in very high cash-out prices in tight network situations.
Siemens Operational Services	**Yes** A full internal Impact Assessment will have to be undertaken to identify the development to software and testing to handle new data flows and processes, changes to operational processes including supporting process map documents for Requirements D6 and D7. The Impact Assessment would generate the software development and testing activities along with implementing changes to operational processes and supporting documentation. There would be less development involved if D7 Option 3 is selected.
EDF Energy	**Yes** EDF Energy is a large generator and supplier of electricity, as well as operating in the forward power markets and Balancing Mechanism. For our retail supply arms, we will need to review and amend risk premiums relating to hedging of power, inability to hedge power and imbalance exposure, as this is based on historical data which will no longer be reflective of likely future outcomes, in terms of trading behaviours and spot prices. This might have impacts on customer contracts, which may need to be reviewed. We will need to inform our customers about any changes to their terms or charges as a result of changes to cashout. This work is largely independent of the alternative options and implementation date. For our generation arm, we will need to review and amend risk premiums relating to hedging of power, inability to hedge power and imbalance exposure. This work is largely independent of the alternative options and implementation date. For our trading business, we will need to retrain our Shift Trading

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	team on imbalance pricing. We will need to completely rewrite our imbalance pricing module. We will need to carry out development work to update our systems for the forecasting of Net Imbalance Volume and cashout prices, to take into account the revised calculations, and addition of new data flows. We will need to carry out strategy reviews relating to our short term trading activity, and may need to modify, amend, or abandon strategies which are currently in place. *Confidential information provided*
E.ON	**Yes** Like other market participants, we will be affected by sharper imbalance prices if the PAR volume is reduced to 50MWh in 2015 and potentially 1MWh from 2018, and the associated incorporation of RSP and VoLL. The impact of the pricing changes will be far more significant than the technicalities of the change itself; we already balance to the best of our abilities but might yet have to review elements of our risk exposure, trading or hedging strategies for operating in a world with more volatile cashout prices, including the risk of incurring very high charges if we happened to be short in certain periods in a tight market. Particularly if RSP and VoLL are incorporated in cashout at the VoLL levels suggested, charges incurred in one settlement period e.g. owing to a plant breakdown, could outweigh the total costs incurred over several months prior; this is essentially an unmanageable risk. Ultimately, increased costs, e.g. to our conventional generation business, if a plant trips, our Climate & Renewables business, if the wind does not blow, and our Supply business, if customer demand differs notably from forecast, could all result in overly penal imbalance charges, and increased risks and cost for the businesses will in turn increase costs to end users. As far as system, process and documentation changes are concerned for P305, undoubtedly some would be required. Moving to single pricing should not be an issue, nor storing the level of PAR, but IT changes would be required to receive minor alterations/additions to BMRA messages. These should be relatively straightforward to cope with, but would impact our interfaces and databases. However more work is required to determine how we might use information such as indicative LOLP and cashout prices, and any further increase in workload, IT and process changes that that would lead to.
SSE plc	**Yes** Trading and back office systems and processes will need to alter data capture routines to manage new and changed data items; and assess new parameters and data when optimising the portfolio and verifying settlement charges.

Respondent	Response
	More complex, structured commercial contracts that reference outturn imbalance prices will need to be amended to manage the altered price structure from dual to single cash-out. NHHDA services will be impacted, but it is difficult to fully assess to what extent until answers to questions previously raised by SSE at STAG are provided by Elexon (it is assumed that Elexon will manage the change required to centrally distributed NHHDA software, therefore impact upon SSE is more around the process management and triggers should it ever be required to happen). Please see response to question 8 for a list of the issues raised. LDSO systems and processes already establish a link to MPAN within outage systems, but will need to alter to identify IDNO area MPANs as well as notify the relevant DAs of the list of affected MPANs via the agreed communication media.
Centrica	**Yes** Due to the behavioural changes likely to be adopted by the market following the implementation of this modification, and the overall change to imbalance risk, we would need to review and update our forecasting models and processes. Under P305 accurate forecasting of outputs and demands will be a key incentive due to the increased risks associated with imbalance. Refinement of forecasting processes will need to be undertaken to manage this risk. As P305 results in significant changes to the imbalance risk of parties, it is likely that some historical contracts will need to be re-opened and re-negotiated.
G4S Utility and Outsourcing Services (UK) Limited	**Yes** For D7x and D7y we would need to introduce new processes to manage the spreadsheets received as a result of D4.3. It is not clear what the expected volume of these is or if the data will have to be manually entered into NHHDA or loaded through an automated process into NHHDA. D7z has no impact.

Question 2: Will your organisation incur any costs in implementing P305?

Responses

Respondent	Response
Western Power Distribution	**Yes** We will incur one-off implementation costs of around £20,000 to implement the necessary system changes. Ongoing additional costs will be marginal.
TMA Data Management Ltd	**Yes** Medium to high.
IMServ Europe Ltd	**Yes** One off costs: • Development, testing and deployment of System Changes documented in Question 1 for HH changes and testing and deployment of changes for NHH. On-Going Costs: • Additional Training, production of associated Procedures/LWIs, reporting, support, data storage resources, general resources etc. • Additional Auditing/Performance Assurance support • Possible requirement for additional personnel dependent on volume • Additional DTN costs BSC Systems Release: • There would be no difference in costs whether this was implemented as part or outside of a normal BSC Systems Release Alternative Proposals: • There would be little difference in terms of costs between alternative proposals in our roles as HHDA and HHDC
APX Commodities Ltd	**No**
Northern Powergrid	**No** In the event of Demand Control a list of all affected customers and associated energised MPANs will be established from the development of established queries interrogating our Network Management System switching logs and associated connectivity model and Meter Point Administration System (MPAS).

Respondent	Response
	Northern Powergrid does not propose existing data flows are adapted to cater for Demand Control events, nor new flows developed. Use of established queries to extract the data, manually verify and publish will suffice and alleviate the requirement for additional development costs, especially given the expected rarity of these events.
Good Energy	**Yes** • On top of the additional imbalance cost, there will be an unknown additional cost for Good Energy to take remedial action to attempt to mitigate the risk of more severe market prices, the increased credit requirements, and changes to operational elements such as updated systems and processes. • Specific examples of costs related to systems and processes are the need to amend the importing, processing and reporting of data flows that will be affected by the changes. Any new data flows needed will also add additional cost due to the fact that they are not currently imported, processed or reported on. • There will also be the multiple one off costs to update generator PPA's and customer Power Supply Agreements (PSAs) to mitigate imbalance and credit risks. Note that the more contracts in place the higher the relative cost on the supplier in question. • A ballpark estimate of the one off costs involved to Good Energy excluding the impact related to changes in imbalance cost is between £25k and £150k.
SmartestEnergy	**No** Operationally no, since both the SBP and SSP will be retained, but set equal to each other, so there should be no system impacts. Other variables such as LoLP, VoLL and PAR are not brought into our system.
National Grid	**Yes** The cost sensitivity of P305 depends on the extent to which the solution: can utilise existing functionality in our incumbent systems (e.g. MODIS); new data items are required to be introduced; changes are required to the EBS specification for phase 1 or a future release; and any significant changes to our internal and external system interfaces. Based on our experience of the European Transparency Regulation (ETR) project we estimate that P305 will cost between £1 million and £3.5 million. £1 million cost may be achieved if existing infrastructure (e.g. MODIS and other internal systems and processes) can be modified to deliver the solution. £3.5 million cost would be necessary if we are required to procure additional hardware, receive new data from market participants and modify

Respondent	Response
	internal National Grid systems and processes.
Electricity North West	**Yes** This is likely to be a low impact from a script production perspective but a business impact will be incurred for each event although this may be minimal it will mean a consequential impact on other activities due to the importance placed on providing the data and will also depend on the timeline. If required to meet the II run this will be a larger burden than if we had 5 working days to provide the data for onward processing via the SF run. There is no change on the impact dependent upon whether or not they form part of a normal BSC Systems Release.
ScottishPower Energy management Ltd	**No** As for Question 1, P305 will not significantly impact our systems or internal processes but will require a re-consideration and re-evaluation of the risks of more marginal imbalance pricing on our generation and supply businesses. The cost impact of any increased risk may, ultimately, have to be passed on to consumers.
First Utility Limited	**Yes** Costs will relate to the development of systems and processes and their on-going operation and maintenance. These are unknown until the IA has been completed.
Co-Operative Energy	**Yes** It is likely that the reduction of PAR to the extent proposed will result in heightened credit requirements to market participants for both balancing and bilateral trading purposes as the risk created by potentially much higher cash-out prices will almost certainly be factored into these. While the large vertically integrated suppliers are in possession of approved credit ratings which are likely to be accepted as appropriate security for a considerable part (or possibly all) of these increased credit requirements, smaller suppliers tend not to have credit ratings of this sort and are required to post cash or a letter of credit, thus tying up working capital which cannot then be invested in growing the business. This will have a further negative impact on the ability of smaller suppliers to provide wider customer choice and effective competition to the large vertically integrated suppliers.
Siemens Operational Services	**Yes** Costs will arise from the activities outlined in answer to Question 1. There will also be on-going costs if additional DTA flows have to be transmitted and possible additional staff costs associated with the operational running of the processes. There will also be costs incurred in the development and implementation of any solution. It is not possible to quantify the costs until an initial impact

Respondent	Response
	assessment has been undertaken. However the cost involved will not be trivial. As a HHDC/HHDA agent, there would be development costs regardless of which Option is selected. As NHHDA, costs would vary depending on which Option for Requirement D7 is selected. Option 1 (D7x) would be the most costly to develop and run due to DTN costs for the data flows and possible exception handling. There should be no difference in costs due to whether implementation is done as part of a normal BSC System Release or not.
EDF Energy	**Yes** These estimates are largely independent of the alternative options and implementation date. *Confidential information provided*
E.ON	**Yes** For the implementation of the changes rather than the actual changes themselves, some one-off up-front costs will be incurred to make changes to our processes and IT systems, for instance to receive indicative LOLP and cashout price values for every settlement period. We do not anticipate that these changes should be particularly costly. However it is harder to ascertain how we might be impacted by more occasional events such as the need for adjustment of Suppliers' settled nhh volumes following any Demand Control actions affecting our customers. Ongoing costs incurred by P305 implementation may include further cost through increased credit requirements; it is far more difficult at this stage to estimate the potential ongoing cost/risk premium required for attempting to manage the increased risks that more volatile cashout prices will bring. These will undoubtedly be more significant; as noted in our answer to question one it is possible, for instance, that an extremely high SBP for one half-hour could lead to spikes in costs outweighing those incurred for several months (and that this occurs in both our Production and Consumption accounts for the same settlement period). Consequently although it is possible that a direction could be made to lower the level of VoLL, we are wary regarding the proposed suggestion that a change to VoLL could be directed by the Authority at any time. Presently this proposal has no mention of consultation with industry in D1p and the minimum lead time of not less than 12 months is subject to change by the Proposer; should 12 months lead time be changed later in the development of P305, parties should be given a chance to comment on any such change. The D1a alternative gives more comfort that the level of VoLL will be subject to a regular review with industry consultation on both the level and

Respondent	Response
	lead-time for implementation of any change in value, but it is hard to quantify the differences in likely costs between the various Proposed and Alternative suggestions. Cost- and time-wise for the initial P305 implementation itself, within a normal BSC Systems Release is always preferable for us to avoid having to seek a separate approval/budget for IT changes from our Group Management in Germany. In addition to incurring additional costs, this approval in itself can take a few months to receive before work can begin.
SSE plc	**Yes** The vast majority of costs are one-off costs to amend systems and processes to adapt to the new methods of formulating price and volume; and identifying and handling the list of disconnected MPANs and associated volume estimates in the event of an involuntary demand disconnection. Ongoing costs will be minimal. Set up costs for Wholesale business should be low to medium cost (10k – 100k). Set up costs for Distribution business should be low to medium cost (10k - £100k). Set up costs for NHHDA will depend highly upon cost of change to Elexon centrally distributed software. Additional SSE cost beyond central software change is anticipated to be low however, given the assumed infrequency of qualifying events. There is an additional project management overhead associated with implementing change outside of a scheduled BSC System Release, however it would not be of great concern if an ad-hoc release were required as our preference is to work towards a Winter 2015 implementation.
Centrica	**Yes** • In order to manage the increased risk of very high imbalance costs from P305, we will need to improve for forecasting modelling, this would involve system improvements and additional data requirements, we estimate this to cost around £100k in upfront costs and £100k per year for additional FTE to manage this risk, • The contract re-opening will require contract management and legal input, this could result in considerable expense, depending on the number of re-opened contracts. • The amount of credit required to be posted will increase considerably under P305, this will impact all market participants. • With the introduction of a single cash-out price and the corresponding reduction to intraday liquidity, we believe this

Respondent	Response
	will result in increased imbalance costs as parties will be less able to contract imbalances positions intraday.
G4S Utility and Outsourcing Services (UK) Limited	**Yes** Assuming any changes to NHHDA are delivered by Elexon the main costs would be on-going and be for people to process the spreadsheets received from D4.3. It is not clear how many/how often these would be received or how the data would be entered into NHHDA so it is not possible to estimate the cost of running this process.

Question 3: How long (from the point of Authority approval) would you need to implement P305?

Responses

Respondent	Response
Western Power Distribution	**6 Months** We typically require a minimum of 6 months lead time to plan, schedule and undertake system changes including any necessary testing. However, given that resources will be particularly stretched over the next 18 months making smart mete related changes, we would prefer implementation to be no earlier than June 2016.
TMA Data Management Ltd	**9 Months**
IMServ Europe Ltd	**12 Months** • Lead time has been calculated by considering time frames required for developing, testing and deploying the system changes for HHDA and HHDC and testing and deployment of NHHDA changes. • Once system changes deployed for HHDC, HHDA and NHHDA then training and documentation of Work Processes would be required. • This Lead Time also takes into account a number of other Industry Changes currently in progress which requires effort from the same resource pool. • There would be little difference in Lead Times between solutions in our roles as HHDA and HHDC • There would be little difference in Lead Time whether P305 is implemented as part of or outside of a normal BSC Systems Release • In our role as NHHDA there would be little difference in Lead Time between the three proposed solutions
APX Commodities Ltd	**N/A**
Northern Powergrid	**2 Months** Northern Powergrid envisages that from the point of Authority approval, internal procedural documentation can be developed and approved, in addition to robustly testing the data extraction process within two months.
Good Energy	**9 Months** • The 9 months will be needed to model, analyse, agree and then implement the handling of risks and cost related to the

Respondent	Response
	more severe imbalance prices. • Time will be needed to update our internal systems to handle changes to Data flows and also any new data flows that will be created during the changes. • Time will be needed to acquire additional credit lines which may be needed to be placed with Elexon and other counterparties. • The time will also be needed to amend PPAs and PSAs that will need additional risks passed through to customers and generators.
SmartestEnergy	**12 Months** We do not require a lead time from a systems perspective. However, we believe that there should be a 24 month lead time to allow for the market to take account of the changes in the differing prices. There will be a market impact and a contractual one. We would suggest April 2016 for implementation of P305, in conjunction with PAR 350 under modification P314 for the intervening period; a period of PAR 250 with dual cash out is not desirable.
National Grid	**Up to 18 Months (Nov 15 feasible)** Contingent on the final requirements and their complexity, we consider that delivery of a solution is feasible within the presently anticipated timescales (i.e. by November 2015) but may take up to 18 months.
Electricity North West	The lead time is minimal i.e. the production of scripts to obtain the data. The impact on other market participants is likely to be more substantive, so we are happy to defer to their lead times.
ScottishPower Energy management Ltd	**6 Months** Parties require as much notice as possible that the changes to electricity cash-out embodied in P305 will be implemented from a firm date. This will enable Parties to manage their contract positions (generation and supply) in the certain knowledge of which cash-out regime will be in force for future periods and to make appropriate and efficient economic decisions.
First Utility Limited	**6-9 Months** We estimate 6-9 months will be required to specify, develop and test the required systems.
Co-Operative Energy	**6 Months** Although we do not support the proposed reduction of PAR for the reasons discussed above, we believe that a lead time of at least 6 months would be necessary to allow changes to internal hedging strategies.

Respondent	Response
Siemens Operational Services	**Minimum 6 Months** Based on the information available we would expect a minimum of 6 months to implement P305, this would be after the relevant DTC changes for new data flows have been approved.
EDF Energy	**9 Months** The critical path for technical readiness for this change is systems change. We have estimated nine months, given historical timescales for changes of this magnitude. However, EDF Energy, like a number of other large participants in the market, is obliged by Ofgem to place bids on the forward market to buy and sell power. These bids are required to be placed on the forward market up to season +4, with a mandated maximum spread. It is argued by Ofgem that this suite of modifications is likely to have an effect on forward curve prices, in order to incentivise the construction of new plant or disincentivise the decommissioning of old plant. It appears to us to be unfair to mandate companies to take a long or short position in forward power, and then to change one of the factors affecting the price of these trades. To mitigate this, we would require between twenty four and thirty months' notice of implementation, with a preferred date of 1st April or 1st October 201X, being the start of the first Gregorian Season for the trading of power which is not covered by Ofgem's Market Making Obligation.
E.ON	**3-6 Months** We currently invest significantly in demand forecasting and do not believe that any particular improvements could be made here, hence would not be looking to improve our forecasting capabilities in advance of P305 implementation. On the contrary, the prospect of incurring extremely high costs in occasional half-hours, wiping out any benefit from being a 'better balancer' in most periods, rather undermines the case for any further investment in demand forecasting. As far as wind forecasting and plant availability go, we doubt that significant improvements in the former are possible, while unexpected issues may arise with any plant from time to time. Consequently E.ON does not presently expect to incur particular costs or require a lead time specifically with regard to improving forecasting capabilities in preparation for P305. As per our answer to question 2, we also do not anticipate major IT changes to be required; however some work will be necessary. While this might not take long to undertake, approval/budgeting for such work is more problematic if outside a BSC Systems Release. Implementation as part of a release is always preferable to avoid having to seek separate approval for IT changes from our Group Management in Germany, this process can sometimes take a few

Respondent	Response
	months, hence if outside a BSC release >3-6 months would be required solely to allow for IT changes. More fundamental strategic/behavioural/ process changes to address the increased risk that higher and more volatile imbalance costs would bring will take more time to implement.
SSE plc	**6 Months** Our preference would be to incorporate as part of a normal BSC Systems Release as this is more efficient to manage from both central and Parties' perspective. However, SSE are keen to ensure that this modification is implemented in time for Winter 2015, so would be able to manage as a stand alone release if necessary to meet the date aspired to in the EBSCR conclusions.
Centrica	**12 Months** As processes, controls, strategies and systems will require updating as a result of this change, we suggest a year is an appropriate timescale between an Ofgem decision and the implementation of this modification.
G4S Utility and Outsourcing Services (UK) Limited	**3 Months** 3 months would be required to understand and train staff to run the new process for D7x or D7y. It would make no difference when this happened. No other part of the proposal would have any impact.

Question 4: Do you have a preferred option for Requirements D1, D7 and/or D9?

Responses

Respondent	Response
Western Power Distribution	We have no comment on this.
TMA Data Management Ltd	**D7z** We prefer D7z as it does not impact NHHDA.
IMServ Europe Ltd	No direct comment • Requirement 7 would be centrally developed (as per response to Question 1)
APX Commodities Ltd	**D1a** For D1 we have a preference for the workgroup's preferred alternative.
Northern Powergrid	-
Good Energy	**D1a; D7x; D9a** D1 – Process for Changing VoLL • D1a is preferable because VoLL changes would follow an established BSC process rather than allow Ofgem to direct changes at its discretion, which does not seem condusive with better regulation principles. D7 – Estimate of Demand Disconnection volumes for NHH MPANs and adjusting Suppliers' settled volumes • D7x is preferable because it calculates the demand disconnection volumes on the same basis as calculating other NHH demand. There is less risk to trading parties, however we recognise that it is likely to be costly to implement. Therefore we suggest there needs to be a review of the cost vs benefits of implementing different options. D9 – Estimate of Demand Control volumes in the Main (Imbalance) Price Calculation • Cash-out prices changing from one Settlement Run to the next complicates the billing of PPAs & PSAs that mirror cash-out prices. It also means that suppliers and generators will not know their overall positions until 18 months in arrears. • D9a seems preferable to D9p because it avoids the Main Price in SF & subsequent Settlement Runs being different from in the II run. • A better solution would be to allow the more accurate

Respondent	Response
	calculation of the demand control volumes proposed by D9a for SF & subsequent Settlement Runs just apply at SF and then be frozen at the SF level, this would allow a more accurate settlement of imbalance prices, but would not significantly impact the settlement of various financial positions within the market that depend on imbalance prices.
SmartestEnergy	**D1a; D7x; D9a** D1 – we prefer the alternative over the proposal on the basis that the value of VoLL should not be directed by the Authority, bypassing normal change procedures. Having said that, we also believe that a Panel review does not have to be annual if the value is indexed. D7 – the first option (D7x) appears to be more accurate and therefore more preferable D9 – the proposal appears to ignore voltage reduction on occasions where there is also demand disconnection. The alternative (D9a) would appear to be preferable.
National Grid	**D9a** <u>Requirement D1</u> We recognise that the Value of Lost Load (VoLL) will play a critical role in determining the imbalance price risk that market participants face; consequently it will be a key component in informing hedging and investment decisions. Whether the lead or proposed solution is decided upon, it is therefore important that the process for governing the VoLL is one that gives sufficient confidence to both market participants and Ofgem in its rigour, transparency and stability. <u>Requirement D7</u> We do not have a preference between the options under requirement D7. <u>Requirement D9</u> We support the alternative proposal put forward by the working group under requirement D9. The reasoning that supported this alternative was that to be consistent with the current arrangements for feeding other accepted actions (e.g. BOAs) into the cash-out price calculation, this should be on the volume instructed which is not subsequently corrected for volume delivered. It was also noted that in principle the cash-out price should be based on the volume that was deemed necessary at the time of instruction to ensure the system is balanced. Having the imbalance price for all Settlement Runs based on the original volume estimation will reduce the potential for significant movements in the imbalance price for a Settlement Period and reduce uncertainty for market participants in this respect. This is particularly true under D9p.5 which, for the SF and subsequent Settlement Runs, proposes to ignore any volume

Respondent	Response
	attributed to Voltage Reduction in the case where there is both demand disconnection and voltage reduction.
Electricity North West	Our understanding is that this would not be applicable to a distributor
ScottishPower Energy management Ltd	**D1a; D9a** For Requirement D1, ScottishPower prefers the Alternative Modification (D1a) which places the value of VOLL under periodic review by the BSC Panel, with any proposed change subject to the normal BSC change process including industry consultation. For Requirement D9, ScottishPower prefers the Workgroup's Alternative solution (D9a) which uses a single methodology for calculating the volume of Demand Control Actions for all Settlement Runs.
First Utility Limited	**D1a; D7z** D1: "a" is our preferred option as it has greater visibility and transparency. We also believe it is right for the industry to determine the value against the applicable BSC objectives. D7, our preference is option 3, as we believe that there may be a cost benefit in accepting a level of potential misallocation v cost of implementing a more complex system (option1) however, we await analysis that demonstrates whether the misallocated volumes under this option are material and have the potential to distort competition. If they turn out to be material then our preference would be option 1. Option 2 appears to be a compromise on settlement quality but for the same degree of effort.
Co-Operative Energy	**D1a** We would support requirement D1a as this provides the ability for the BSC Panel to review the VoLL value before potentially making a recommendation to the Authority for this to be changed, rather than the Authority being able to change this at its discretion as under requirement D1p. With regards to D7 and D9, we have no specific preference.
Siemens Operational Services	**D7z** Our response is only for Requirement D7; D1 and D9 do not affect our roles. Option 1 – The steps D7x.4-D&x7 will ensure that the mpan-level data held in the NHHDA and SVAA are synchronised. This is gives the Suppliers more transparency due to their relationship with NHHDAs. But potentially this would generate more exceptions than other Options. Additionally there would the complication of reporting of data spread across multiple market participants. Option 2 – Simpler to implement, with less impact on NHHDA

Respondent	Response
	Agents. However, it could lead to discrepancies between the data held by the Supplier's NHHDA and the SVAA. Option 3 – All the processing sits with the SVAA. No apparent impact on NHHDA. As a NHHDA agent this would our preferred choice. There would still be development for the HHDA system.
EDF Energy	**D1a; D9a** **D1 Changes to VOLL:** We prefer the alternative proposal for D1. Compared with the proposal, this would allow industry itself more influence over the size and timing of any changes to VOLL. Many industry contracts, agreements and investments extend for many months or years into the future, and are based on market rules and parameters known at the time. The administrative and commercial impacts of changes to fundamental market parameters or rules deserve full industry consideration to avoid inefficient costs and windfall gains or losses which could distort competition and affect investment. **D7 Demand Control volume adjustment per Supplier:** D7 Options 1,2,3 appear to involve successively simpler and probably less accurate approaches. Demand control due to national energy scarcity should remain a very infrequent event, but the materiality for affected participants could be high if it occurs. While option 3 appears simplest and does not appear to involve NHH supplier agents, we have some concerns that the approximations could lead to material inaccuracy if it is used. Option 1 should provide more accuracy, but at more cost and effort, with option 2 in between. We think all three options should be kept open for now, and attempts made at costing them, at least until after the assessment consultation stage. **D9: Demand Control volume in imbalance price calculation:** The proposal appears to have differences between demand control volumes used in the imbalance price calculation at the initial stage, and volumes used in later settlement runs, and inconsistency between voltage reduction and disconnection. These would lead to changes in Net Imbalance Volume (NIV) after the event, and could lead to uncertainty and volatility in imbalance price for a given settlement period (bearing in mind various tagging and flagging processes), which would reduce its effectiveness as a short term signal for efficient behaviours. We see advantages in the imbalance price being firm as soon as possible, based on the actions taken by the System Operator. The System Operator should have the best view of the volumes it expects to get at the time it issues its instruction. If the result of its instruction turns out to be too little, more will be required. If the result of its instruction turns out to be too much, then actions in the opposite direction will be required (for example turning down

Respondent	Response
	marginal generation) and these will feed into "NIV tagging" in the normal way. NIV would remain the same in each successive settlement run, with participant imbalance volumes adjusted for refinements in individual volumes, but the imbalance price remaining essentially the same. These advantages of an early determination of total demand control volumes based on NGET instructions seem to favour the D9 alternative approach. Note that D9a6 suggests that initial estimates of demand control volume should be used as part of the adjustment of suppliers' imbalance positions. Only D7 option 3 would use the total demand control volume in its estimation of the impact on individual supplier volumes.
E.ON	**D1a** For D1, like the Workgroup we clearly prefer D1a. As mentioned in our answer to question two, parties can deal with a regular review, that can be anticipated and with the confidence that they will be fully consulted. For the Authority to direct a change however we would consider an unacceptable, unprecedented step outside the spirit of GB industry Code modifications. It needs to be clear that a review process will involve feedback from parties and adopting a process akin to the MIDS review would best achieve this. The fact that the Panel could instigate a review on the request of the Authority means that the intervals between reviews might not be exactly annual, but this should give Ofgem the comfort that a change could be raised at their request at any time if deemed desirable; ultimately the Authority would still approve whether or not to implement a change. For D7, it is hard to express a preference until further information is available, we would appreciate visibility of the parallel analysis being undertaken for the next P305 Workgroup, as mentioned in the Impact Assessment. We understand that this should include identifying the extent of any discrepancy between the calculation of disconnection volumes using the more accurate Requirement D7x Option 1, and D7x Option 3, the simplest approach, and whether there are any material distributional effects (for instance to what extent disconnected suppliers benefit and non-disconnected suppliers might not). For D9 the important point is that for transparency all individual instructions will be published on the BMRS in accordance with D2. When it comes to these actions entering cashout we can see the logic behind both the proposed approach to utilise the same more accurate bottom-up volume to correct Suppliers' positions and enter the Main price calculation, and the alternative to retain the top-down estimate for pricing, as in practice for BOAs. The proposed approach should indeed be more accurate, but we do share the concern of some in the Workgroup that this could change prices; also, given the uncertainty around accurate calculation of voltage control

Respondent	Response
	volumes, the alternative would probably be simpler and clearer.
SSE plc	**D1a; D7z; D9a** Requirement D1 - our preference is for Requirement D1a. We do not believe that the Authority should have discretion to propose a change to the parameter when and if it wants to. The change of the parameter should be managed through existing industry/Code led procedure as contemplated in D1a. Requirement D7 – no strong preference. Our NHHDA has a slight preference for Option 3, given its simplicity relative to other options. Requirements D9 - our preference is for Requirement D9a as it is much simpler, gives greater certainty to the price signal and is consistent with the way that other data is treated in constructing the price.
Centrica	**D1a; D9a** D1 – We prefer the alternative for D1 as we do not support setting a precedent and by allowing Ofgem to be able to direct a change to BSC (the value of lost load) without following due process. D7 – We are awaiting more information from Elexon's analysis in this area before making a decision on which option we prefer. D9 – We prefer the alternative option for D9 as we suggest there should be a consistent approach to settlement runs.
G4S Utility and Outsourcing Services (UK) Limited	**D7z** We have no preference for D1 or D9. For D7 z is our preferred as it appears the simplest with the fewest manual steps, and fewer places for errors or where exceptions could occur. We believe D7x is significantly more complex and would require a lot of added complexity if it was to cover all scenarios so this is our least preferred option. These preference are based on the complexity of the processes and not the accuracy of the outcome.

Question 5: Do you believe there are any other possible alternative solutions to P305 that the Workgroup should consider?

Responses

Respondent	Response
Western Power Distribution	**No**
TMA Data Management Ltd	No comment
IMServ Europe Ltd	**No** • We believe this is the optimal solution for a 'bottom-up' approach • Has consideration been made as to whether this should sit within existing Party Agent BSCPs? There have now been a number of Industry Changes in a very short timeframe causing the HH BSCPs to be revised and extended beyond their original purpose. Perhaps these changes would be better captured in a separate Procedure in order to prevent existing BSCPs loosing their focus?
APX Commodities Ltd	**No**
Northern Powergrid	**No**
Good Energy	**Yes** Level of PAR at implementation of P305 • Good Energy suggests that PAR should be set at a less severe level such as PAR100 rather than PAR50 from the implementation date, to continue the step change reduction in PAR that the industry has generally requested to monitor and adapt to the behavioural changes that will occur in the market. • PAR could then be further reduced the following April to PAR50, this would allow all participants in the market to have the whole of the summer to monitor the effects of PAR50 on their positions, and put in place any coping strategies needed before the following winter.
SmartestEnergy	**No**
National Grid	**No**
Electricity North West	**Yes** Undertake a 'top down' approach and consider how improvements to the accuracy can be attained at a central agent level rather than obtain data to produce a 'bottom up' solution resulting in a number of industry parties being impacted for what has yet to be proved to

Respondent	Response
	be a cost effective solution.
ScottishPower Energy management Ltd	**No** We consider that the Workgroup has considered all reasonable solutions to P305.
First Utility Limited	**Yes** We have concerns with the implementation approach because it does not include checking that the reduced PAR values are achieving the desired outcomes and that these are not outweighed by unintended side effects. The final targeted minimum PAR value supportable by the industry needs to be related to the sufficiency of liquidity in traded products pre-gate closure to enable the management of imbalance volume risks – as it makes no sense to increase imbalance risk in the absence of availability of the risk management products in the market needed to manage those risks. We believe the final value should be higher than PAR 1 and that further work needs to be done to determine this. We therefore propose an approach of: Par 400 implement 1st Oct 2015 review after 6 months. Par 300 implement 1st Oct 2016 review after 6 months. Par 200 implement 1st Oct 2017 review after 6 months. A review by the BSC against the BSC objectives of the benefits of the sharper price signal v the dis-benefits taking into account issues such as market liquidity, adverse distributional impacts and any other identified side effects that may unduly distort competition. If at any point it is determined that the progression is detrimental to the BSC objectives, the PAR value will revert to the previous level. The decision to progress below PAR 200 should be taken at the PAR 300 review.
Co-Operative Energy	**Yes** We believe that single-priced cash-out should be implemented as soon as possible and more time allowed to observe the effects of this in tandem with the implementation of P304 or P314 (reduction of PAR to either 250MWh or 350MWh) dependent on which of these Ofgem chooses or the retention of a PAR of 500MWh should neither of these be implemented.
Siemens Operational Services	**No**
EDF Energy	**No**
E.ON	**No**

Respondent	Response
	To do so would be very difficult, given the multitude of issues raised in the description of the defect (PAR Level, Reserve Pricing, Pricing Demand Control, and Single Cash-out Prices), but current restriction to only one Alternative proposal under the BSC.
SSE plc	**No**
Centrica	**Yes** We propose that a reduction to PAR100 should be implemented instead of a reduction to PAR50 and that the reduction to PAR1 should be removed from the modification. Additionally RPAR should not be altered. We believe that introducing PAR50 will result in extremely volatile and unpredictable imbalance charges. We do not believe this will benefit the industry and it may result in market players having to accept high imbalance charges (resulting in random winners and losers) rather than being able to react to market signals and thus preventing further market stress from occurring. Inducing a PAR1 will magnify this issue and is far less likely to provide signals for the market to react to. If in future, following in-depth market analysis of the impacts to the reduction in PAR, including the impacts from a system that is shorter and more likely to result in higher imbalance charges, a reduction in PAR is considered necessary, this should be achieved via a further modification proposal, rather than within this modification before the full impacts can be fully considered.
G4S Utility and Outsourcing Services (UK) Limited	**-**

Question 6: Do you agree with the Workgroup that the final LoLP value should be published as soon as possible after Gate Closure (Requirement C3)?

Responses

Respondent	Response
Western Power Distribution	We have no comment on this.
TMA Data Management Ltd	**Yes** This value can have a significant impact on Suppliers imbalance cost and should be provided as soon as possible after it is calculated.
IMServ Europe Ltd	No view at this time
APX Commodities Ltd	**Yes** The information should be published as soon as it is available as LOLP in one settlement period may be related to LOLP in a subsequent settlement period.
Northern Powergrid	-
Good Energy	**Yes** Publishing the data as soon as possible will allow the market to react to what the likely LoLP is for future periods slightly after the period in question, it will allow for better pricing signals to be present in the market.
SmartestEnergy	**Yes** We understand that the argument in favour of delaying publication until after the beginning of the settlement period in question is that earlier publication would give an advantage to participants who have flexible generation. We are not convinced this is the case as there will clearly be no surprises in terms of the overall likelihood and tweaking positions on the basis of a small revision to LoLP will be futile. On the other hand, it would be absurd to publish a value of a forecast when the reality is known.
National Grid	We are keen to make any meaningful market information available to the industry where doing so better enables them to reduce their imbalance risk and helps contribute towards a balanced Transmission System. However we have some concerns that publication of the final LoLP before the relevant Settlement Period has expired may incentivise market participants to deviate from their Final Physical Notifications (FPNs). We note that intentional FPN deviations are prohibited under the Grid Code and therefore this should not occur. In principle we are not opposed to publishing the final LOLPs at Gate Closure, however it may be necessary for increased monitoring of the accuracy of FPN submissions in periods

Respondent	Response
	where higher LOLPs have been notified.
Electricity North West	This is not applicable to the distributor
ScottishPower Energy management Ltd	**Yes** The final value of LoLP should be published as soon as possible after Gate Closure to enable BSC Parties to respond to the value by flexing their demand/generation plant or adjusting their contract position through the market. If Parties do not have sufficient time to respond to changes in LoLP values then the economic justification for P305 is reduced and the increased imbalance prices simply become a penalty rather than a signal to which Parties can respond by changing their behaviour.
First Utility Limited	**Yes** The actual level of LOLP is a key indicator of the value of LOLP in future periods and a useful element in the formation of hedging strategies.
Co-Operative Energy	**Yes** Yes, visibility of this value needs to be provided as soon as possible in order to allow affected parties to take the necessary steps.
Siemens Operational Services	**-**
EDF Energy	**Yes** Publishing information as early as possible should help market participants take efficient actions, and would be consistent with European initiatives for transparency in markets and operation. LoLP would be a constituent of the imbalance price, and advance notice should inform efficient participant behaviours. Licensed generators are restricted from certain actions after gate closure, but would be better informed to take efficient actions in relation to periods for which gate closure has not yet occurred. The market in general would have opportunity for further action to help resolve shortfalls efficiently. With single imbalance price, or explicit post-gate trading, there would be opportunity for bilateral trading. It could also be an effective or convenient signal for voluntary demand response. If NGET or regulators had evidence that actions were not being taken efficiently as a result of final LOLP being published soon after gate closure (for example additional costs incurred by NGET), this should be addressed separately.
E.ON	**Yes** Yes, we agree with the Workgroup, we cannot see any good reason for withholding final LOLP information from parties once it has been

Respondent	Response
	calculated.
SSE plc	**Yes**
Centrica	**Yes** There is no logical reason to not publish it as soon as possible following gate closure.
G4S Utility and Outsourcing Services (UK) Limited	**-**

Question 7: Do you believe that the 'bottom-up' calculation for correcting participants' imbalance positions (Requirements D4-D8) could be completed in time for the II Settlement Run?

Responses

Respondent	Response
Western Power Distribution	We have no comment on this.
TMA Data Management Ltd	**Yes** The calculation could be done by II for HH sites. The calculation could be achieved by II for NHH sites as long as they are Smart or Advanced meter equipped.
IMServ Europe Ltd	**Yes** On the basis, in line with the Impact Assessment documentation, that states that the 'bottom-up' calculation is performed at SF Settlement Run and all subsequent Settlement runs, we are happy with this approach On the basis, in line with the Impact Assessment documentation, that states that the 'top-down' calculation is performed at II Settlement Run: • No comment at this time
APX Commodities Ltd	-
Northern Powergrid	-
Good Energy	This is a question specifically for LDSOs and IDNOs.
SmartestEnergy	**Don't know** We cannot comment on this but we are of the view that a top down approach does need to be followed up with a more bottom up approach.
National Grid	We do not have a view on this question.
Electricity North West	**No** We have concerns over the number of market participants involved in the process to meet the tight timescales of an II Settlement run, so it would be difficult to achieve such a tight timescale.
ScottishPower Energy management Ltd	-
First Utility Limited	We have insufficient information to determine this.

Respondent	Response
Co-Operative Energy	**Yes** Yes, we believe that this should be possible provided that enough resource is made available for this.
Siemens Operational Services	**No** See Requirement D4.6 – the LDSO to submit within 5WDs especially it is on a spreadsheet would not give time for the 'bottom-up' calculations to be completed for II Settlement Run. To achieve this target the LDSO/IDNO would have to provide the data earlier, and preferably in data flow format.
EDF Energy	This would depend on provision of data by DNOs and early processing by Supplier Agents. It may be possible to make initial estimates of participants' corrected imbalance positions for the II run, but as with current meter data handling and settlement, it is currently only practical for this to be indicative. More time, and more details of potential IT solutions, would be required to form a firm view on this.
E.ON	We are not in a position to answer this question.
SSE plc	**No** Given that the LDSO business has upto 5 WDs to provide the list of affected MPANs following the cessation of an event, we are not convinced that subsequent processes can be completed with sufficient assurance to meet the current II timetable, given the infrequency of the event and probable need to provide extra validation to ensure that outputs from calculation engines are robust.
Centrica	**Yes**
G4S Utility and Outsourcing Services (UK) Limited	**Yes (for NHH)** For NHH data our understanding from this document is that the imbalance position should be correct at the II run as it would be based entirely on EACs, it is for subsequent run that it would be incorrect.

Question 8: Would you like to make any further comments on P305?

Responses

Respondent	Response
Western Power Distribution	**No**
TMA Data Management Ltd	**No**
IMServ Europe Ltd	**Yes** In our HHDC and HHDA roles we would like to make the following observations: • We would like clarification on the volume and/or frequency of MPANs likely to be affected at any particular time. Will this be a large number of MPANs? • Section 4.5 - Sites registered as De-Energised are covered in this section however what will the approach be for Inactive Feeders? • How will retrospective Energisations be handled? E.g. where there is consumption on a site registered as de-energised that then subsequently is re-registered as Energised • Similarly how will change of agents be handled? For example if an agent is retrospectively appointed or de-appointed for an affected period how will they be notified and how will this data correction be handled? • Section 4.3 - Why can't the HHDC & HHDA be notified via DTC flows? Further, confirmation of acceptance or rejection of the request could be via flow also. • Will this apply to both Import and Export sites or Import only? • Will Reactive Data also need the Data Correction applied? • If a site is contributing to a Complex set up, with particular consideration to 3rd Party Private Networks, how will this be handled? Will the Data Correction be applied to all aspects? • Could there be a conflict with Demand Side Balancing Reserve? For example – a site reacts to a DSBR event and reduces load but then suffers a blackout. HHDC would estimate based on previous surrounding data which would be unlike a DSBR event day. • Section 6.1 suggests Estimating the Meter Advance. How will this work? The suggestion to estimate Meter Advance to the enable estimation of interval data is illogical and no rules exist in BSCP 502.

Respondent	Response
	• How will partial intervals be handled as presumably the Demand Cessation will not be on strict interval boundaries?
APX Commodities Ltd	**Yes** The consultation document asks whether the Market Index Data should be removed. We agree with the views of the workgroup that the cost savings under the BSC may be dwarfed by the consequential cost to industry. There may also be value in a reference price where the method to calculate it is determined by industry and subject to regulatory approval. We understand that the Market Index Price is used in the following calculations: (i) when seeking to calculate value at risk on forward positions (ii) to value structured contracts such as tolling agreements or those with within day flexibility (iii) to plan outages for generation plant and to assess whether flexible plant should be maintained or mothballed, and as part of investment decisions in new plant (iv) to shape products for retails customers using the standard load profiles and to price half hourly metered I&C customers profiles (v) as an acceptable substitute for GB Pool prices where they are still referenced in old contracts (vi) in the calculation of interruption payments and response energy payments under the CUSC.
Northern Powergrid	**No**
Good Energy	**Yes** Comparison to Baseline • Good Energy suggests it is important to ask responders whether they believe that the proposed changes in P305 better facilitate the objects compared to the baseline. This question has not been asked within the Impact Assessment for P305. Voltage Reduction • At Ofgem's insistence Demand Control actions related to voltage reduction are to be included in cash out prices. However, a method for adjusting volumes in response to Voltage Reduction actions has not been developed (as it was considered too difficult) and it is proposed this be progressed separately to P305. GE suggests that it is not sensible to price Voltage Reduction actions at £6,000/MWh for events customers generally do not notice.
SmartestEnergy	**No**
National Grid	**No**
Electricity North West	**Yes** The references to IDNOs in D4 and D5 are misleading. It should

Respondent	Response
	refer to all upstream LDSOs and downstream LDSOs since there can be instances where a LDSO is operating in another LDSO's area as well as IDNOs operating in a LDSOs area. So the requirement will be on the upstream LDSO to notify all downstream LDSO's of such occurrences and not just IDNOs. Whilst it is recognised that a 'bottom up' approach is likely to improve the accuracy of calculation, this seems to be at a significant upfront cost to the industry and impact a number of market participants. It would be worth understanding what granular improvement in the level of accuracy, when measured against the 'top down' approach, is likely to be attained to see if such costs are justified.
ScottishPower Energy management Ltd	**No**
First Utility Limited	**Yes** The high-level impact assessment carried out by OFGEM during the EBCR process illustrates the high-level impact of the proposals. We believe the IA was inadequate and insufficient as there was no evidence to suggest that these changes will improve any BSC objectives. In particular the analysis needs to be done at participant level and smaller sub groups. With sharpening prices, the ability of parties to hedge their position is essential. Appropriate liquidity in wholesale product must exist to allow parties to manage their electricity volume positions. At present we have strong concerns that the requisite liquidity may not be present at times of scarcity. Prices should not be sharpened if the tools available to all participants to manage the risk are not present. No hard evidence has been produced to determine that PAR 1 is the optimal value for the market against the BSC objectives. The market is complex and has many facets and it is impossible to foresee all outcomes. In addition many other changes are occurring in the market that may interact with the issues that P305 is addressing, such as EMR, DSBR, etc. The effectiveness of these may negate the need for the full implementation of P305. We therefore suggest a staged process of change, review and change again. At each stage of reduction, the BSC Panel needs to check that the previous reduction achieved the desired outcome before continuing to the next stage. If at any point the BSC objectives are not met the PAR reductions must stop and revert to the prior value. We do not believe that the inclusion of market signals connected with the value of lost load will be sufficient in terms of reliability and persistence to encourage any significant new investment. We believe the capacity mechanism and the DSR mechanisms run by

Respondent	Response
	NGC will be far more effective tools and much simpler to implement. We think these mechanisms add unnecessary complexity to already very complex systems and that the marginal benefit of this against all the other mechanisms is unproven. In Summary: 1) The analysis is lacking with respect to understanding the adverse distributional impacts by market participant type, we are concerned about the impact of these changes on supply competition. 2) We believe that a final PAR value of 1 is likely too low and that a phased approach should be taken. At each phase the impact of the previous reduction on competition should be investigated.
Co-Operative Energy	**Yes** We would like to reiterate our view that reduction of PAR to the very low levels proposed is likely to create unmanageable levels of imbalance risk for non-vertically integrated smaller suppliers, a serious detrimental effect on competition and market entry and likely exacerbation of the issue that the modification is seeking to correct in the short term. As stated, we support the introduction of single-priced cash-out as we believe this will remove a great deal of the current incentive to vertically integrate which dual-priced cash-out creates. However, we feel that this needs to be linked to a reasonable level of PAR as a very low level (and, in particular, 1MWh as proposed) will create a separate strong incentive to hold back generation as an imbalance hedge and thus cancel out the value of the introduction of single-priced cash-out.
Siemens Operational Services	**Yes** 1) In Requirement D4.3 it states the LDSO will notify the HHDA, HHDC and NNHDA of disconnected mpans via the use of a spreadsheet. This is approach is disappointing as the data is then transmitted between the other participants in the process via the use of (new) data flows – Requirements 6 and 7. Not using DTA flows will make an automated solution more difficult to implement, with the potential for more errors especially if the spreadsheets have to be manually handled which will consume additional staff resource. It appears to be inconsistent with the rest of the outlined process to be using spreadsheets, especially as the LDSOs are already familiar with the use of data flows. 2) The Workgroup needs to consider the situation where NHHDA does not hold a valid EAC for the settlement date. In the aggregation process a default value is used, but this is calculated in one of 2 ways, either a GSP Group Class average value, or an average value based on the mpans in that Settlement Class, which is calculated by the application on the fly and not retained in the NHHDA database.

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	How will this be accounted for in the new process and which party (SVAA or NHHDA) will be responsible for calculating the adjusted volume from such a default value? 3) What about disconnection events that span Change of Supplier? 4) Have Erroneous Transfers been considered? 5) How will the SVAA be sure it has received all required files from all DA's? 6) Impact on NHHDC/NHHDA reporting - we may need to rewrite existing % AA reports etc 7) Possible increase in exception handling for NHHDA's, with associated costs, and investigation requested by the Supplier of the values used in a given aggregation run. While a report option does exist to output the mpan values used in aggregation (the L0038 report), this is not produced as standard for all runs because the size of the files is prohibitively large. More sophisticated reporting within the NHHDA application would be desirable if D7x is selected.
EDF Energy	**No**
E.ON	**No**
SSE plc	**Yes** NHHDA SSE have raised the following questions with Elexon and STAG with regard to the process that should apply in the event of an involuntary demand disconnection. Elexon and the workgroup should consider these issues when formulating an agreed solution :- 1. How will the process be initiated? What will cause the NHHDA to take action? Triggered by a DTC flow or requiring manual intervention? 2. Would null flows be sent at all other times to understand that no action is expected? 3. How will NHHDA handle and read a spreadsheet file format? Would it not be preferable to create and use a DTC flow? 4. What error handling rules will apply for registration mismatches (e.g. MPAN not held by NHHDA)? 5. Would impacted Suppliers receive copies of new flows from NHHDA to support independent verification? 6. How will the settlement period impacted be communicated - NHHDA deals in settlement days rather than half-hourly intervals?

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	LDSO Requirement D5.2 requires LDSO or IDNO to submit BM Unit ID and affected settlement periods to CDCA for further processing. Our LDSO systems recognise MSIDs rather than BM Units, which we suspect may also be the case for other LDSOs. We would prefer the terminology to change to refer to MSID rather than BM Unit. It would then be upto CDCA to determine how to aggregate any volumes estimates in accordance with submitted aggregation rules.
Centrica	**Yes** As the risks of incurring very high imbalance charges will increase with the implementation of P305, the current settlement processes should be upgraded to ensure imbalance volumes are accurately calculated. This is especially the case in relation to non-half hourly (NHH) metered customers. The current settlement processes associated with NHH metered customers has inherent inaccuracies in determining suppliers' actual imbalance volume as opposed to the calculated imbalance volume. Further changes and improvements should be made to the NHH settlement process to improve the accuracy of imbalance volumes, this should include: • half hourly settlement for customers with smart meters • improving the accuracy of allocation for customers without smart meters • accurate measurement of micro generation volumes • measuring unmetered supplies (UMS) • Improvements in the settlement performance. Further work should also be carried out to determine the impact on intraday liquidity as a result of single cash-out prices being adopted, especially when the system is under stress.
G4S Utility and Outsourcing Services (UK) Limited	**Yes** 1. D4.5 – excluding mpans trading as de-energised from the notification list will introduce in-accuracies. Notification of a successful de-energisation can take a number of days to reach all industry parties so at the time the notification list is created the energisation status may not be correct in the SMRS/LDSO/IDNO. 2. D7x.1 – it is not clear when the DYYYY flow would be sent for a disconnection event. We believe it would have to be sent at a minimum every time the eac/aa changes. 3. D7x.1 – assume the DYYYY would contain all the data items required for SVAA to produce a DZZZZ flow eg SSC, TPR. 4. D7x.2/D7x.4 – it is not clear what the mpan disconnection volume estimate is, we assume this is an estimate of the

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	consumption during the disconnection event. 5. D7x.4 – it is not clear if the adjusted AA is just for the settlement day(s) of the disconnection event or the original AA period. We assume it is for the original AA period from Appendix 3. 6. If our assumptions in 4 and 5 are correct we believe a more accurate calculation could be made if the adjusted AA was the sum of the original AA and an annualised mpan disconnection volume. 7. D7x.6 – we assume equivalent NHHDA validation would be applied to the DZZZZ as is currently applied to the D0019. Therefore the process would need to allow for D0023s from NHHDA to SVAA. They may also need to be some new D0095 error codes. 8. D7x.8-D7x.10 – how does SVAA know if 'corrected' AA data is included in the D0041, we assume it would not be desirable to subtract the disconnection volume estimate from the AA data if the adjusted AA has not been included in the D0041 calculations. 9. D7x - We are surprised there is no step to pass the disconnection volume estimate to the supplier, we assume this information would be useful for forecasting and reconciliation. 10. D7x - Disconnection events may cover more than one AA/EAC/SSC/PC/ES/Supplier therefore we assume this process would have to handle these scenarios. 11. D7x.11 – an EAC (and AA) can be replaced between settlement runs, eg following a change of profile class, as a result of reading history review after a subsequent reading, therefore we assume all steps of D7x would need to be repeated as data changed if the intention is to use accurate estimates. But we also highlight that usually NHHDA holds an EAC or and AA for a settlement day so the DYYYY flow will not usually contain both and EAC and an AA for a single mpan. 12. D7y – we do not believe there is any need send AAs on the DYYYY flow. As for D7x the EAC sent on the original DYYYY flow may be changed by standard processes between NHHDC and NHHDA so it may be desirable to repeat the sending of this flow if the EAC changes in NHHDA. However we note this adds complexity to this option.