ASSESSMENT CONSULTATION for Modification Proposal P211
'Main Imbalance Price Based on Ex-Post Unconstrained Schedule'

Prepared by: P211 Modification Group

For attention of: BSC Parties and other interested parties
Responses due: **12:00** on **28 August 2007**
(to: **modification.consultations@elexon.co.uk**)

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This document has been distributed in accordance with Section F2.1.10 of the Balancing and Settlement Code.[1]

Proposed Modification P211 seeks to amend the calculation of the "main" imbalance price such that when the market is short (NIV>0), System Buy Price (SBP) will be based on the least expensive Offers that the System Operator (SO) could have utilised on an unconstrained system. Conversely, when the market is long (NIV<0), System Sell Price (SSP) will be based on the least expensive Bids that the SO could have utilised on an unconstrained system. PAR Tagging would then be applied to the new Ex-Post Unconstrained Schedule (EPUS) price stack to ensure that only the most expensive 500 MWh of Bids or Offers are used to set the main price. The 'reverse' price would remain unchanged.

Potential Alternative Modification P211 is the same as the Proposed Modification described above but using spot values and dynamic parameters to modify the Bid and Offer volumes that make up the EPUS stack. This aims to better reflect what Bid and Offer volumes are actually available to the SO. Whilst the Modification Group has developed this potential Alternative it has not yet been able to evaluate whether this better facilitates the Applicable BSC Objectives than the Proposed and thus whether it constitutes a formal Alternative. However, the Group did wish to consult the industry on the principles of this potential Alternative.

PURPOSE OF CONSULTATION

This consultation seeks respondents' views regarding P211 and, in particular:

- Do respondents have a view of the extent/impact of the perceived defect identified under P211?
- What are respondents views on 'simplicity' versus 'cost-reflectivity' on the calculation of the main imbalance price?
- Whether the Proposed Modification would better facilitate the achievement of the Applicable BSC Objectives[2] when compared to the current Code baseline;
- Whether the potential Alternative Modification would better facilitate the achievement of the Applicable BSC Objectives when compared to the Proposed Modification;
- Do respondents have any views on how these solutions will influence market participants' balancing behaviours and any subsequent impact on the SO?
- Do respondents support the approach of only building enough of the DAOV/DABV stack to calculate

[1] The current version of the Code can be found at http://www.elexon.co.uk/bscrelateddocs/BSC/default.aspx.
[2] A copy of the Applicable BSC Objectives is provided in Appendix 1.

Energy Imbalance Prices to ensure minimal impact on prompt prices (see section 3.5 below)?

- Whether there are any alternative solutions that the Modification Group has not identified and that should be considered; and
- Whether there are any substantive issues not considered by the Modification Group which should be brought to the Group's attention for inclusion in its assessment of P211.

You are invited to provide a response to the questions contained in the attached pro-forma.

Please send responses, entitled 'P211 Assessment Procedure Consultation', by **12:00** on **28 August 2007** to the following e-mail address: modification.consultations@elexon.co.uk.

Any queries on the content of the consultation pro-forma should be addressed to Chris Stewart (020 7380 4309), e-mail address chris.stewart@elexon.co.uk.

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SUMMARY OF IMPACTED PARTIES AND DOCUMENTS

As far as the Modification Group has been able to assess, the following parties/documents would be impacted by P211.

Please note that this table represents a summary of the full impact assessment results in Appendix 3.

Parties		Party Agents		BSC Agents		Other Agents	
Distribution System Operators	☐	Data Aggregators	☐	SAA	☒	Supplier Meter Registration Agent	☐
Generators	☒	Data Collectors	☐	FAA	☐	Unmetered Supplies Operator	☐
Interconnectors	☒	Meter Administrators	☐	BMRA	☒	Data Transfer Service Provider	☐
Licence Exemptable Generators	☒	Meter Operator Agents	☐	ECVAA	☐		
Non-Physical Traders	☒	ECVNA	☐	CDCA	☐		
Suppliers	☒	MVRNA	☐	TAA	☐		
Transmission Company	☒			CRA	☐		
				SVAA	☐		
				Teleswitch Agent	☐		
				BSC Auditor	☐		
				Profile Administrator	☐		
				Certification Agent	☐		

Sections of the BSC			
A	☐	P	☐
B	☐	Q	☒
C	☐	R	☐
D	☐	S	☐
E	☐	T	☒
F	☐	U	☐
G	☐	V	☒
H	☐	W	☐
I	☐	X	☒
J	☐		
K	☐		
L	☐		
M	☐		
N	☐		
O	☐		

Code Subsidiary Documents		Core Industry Documents		BSCCo		BSC Panel/Panel Committees		Other	
BSC Procedures	☒	Ancillary Services Agreement	☐	Internal Working Procedures	☒	Working Practices	☐	Market Index Data Provider	☐
Codes of Practice	☐	System Operator – Transmission Owner Code	☐					Market Index Definition Statement	☐
BSC Service Descriptions	☐	Data Transfer Services Agreement	☐					System Operator-Transmission Owner Code	☐
Party Service Lines	☐	Distribution Code	☐					Transmission Licence	☐
Data Catalogues	☒	Distribution Connection and Use of System Agreement	☐						
Communication Requirements Documents	☐	Grid Code	☐						
Reporting Catalogue	☒	Master Registration Agreement	☐						
		Supplemental Agreements	☐						
		Use of Interconnector Agreement	☐						

1 EXECUTIVE SUMMARY

The key conclusions of the P211 Modification Group ('the Group') to date are outlined below.

The Group:

- **AGREED** by majority an initial view that the Proposed Modification would not better facilitate the achievement of Applicable BSC Objectives (b), (c), or (d).
- **AGREED** that a Potential Alternative Modification should be developed in order to attempt to better reflect what the System Operator (SO) could have procured to meet the Half Hourly integrated value of the Net Imbalance Volume (NIV).
- **AGREED** by majority an initial view that the Potential Alternative Modification would not better facilitate the achievement of Applicable BSC Objectives (b), (c), or (d).
- **NOTED** that the implementation costs for the Proposed Modification were estimated to be £346,000 for ELEXON and BSC Central Systems and approximately £80,000 for the Transmission Company.
- **NOTED** that the implementation costs for the potential Alternative Modification were estimated to be £435,590 (for a reduced reporting option) or £454,960 (for a detailed reporting option) for ELEXON and BSC Central Systems and approximately £90,000 for the Transmission Company.
- **NOTED** that the Modification Group initially agreed that an implementation solution that required the Transmission Company to calculate the EPUS stack or main Energy Imbalance Price and provide this to BSC Central Systems was not to be pursued for either the implementation of the Proposed or potential Alternative Modification. This was due to the Transmission Company stating that it was not feasible in terms of both cost and timescales.
- **NOTED** the Implementation Date for Proposed Modification P211 should be 6 November 2008 if an Authority decision is received on or before 28 February 2008, or 25 June 2009 if the Authority decision is received after 28 February 2008 but on or before 16 October 2008.

A description of the P211 Proposed and potential Alternative solution is provided in Section 2. Further information regarding the Group's initial discussions of the areas set out in the P211 Terms of Reference is contained in Section 3.

A summary of the Group's initial views regarding the merits of the Proposed Modification and potential Alternative Modification can be found in Section 3.7. A copy of the Group's full Terms of Reference can be found in Appendix 2, whilst a summary of the responses to the impact assessment can be found in Appendix 3.

2 DESCRIPTION OF MODIFICATION

This section outlines the solution for the Proposed Modification and Potential Alternative Modification as developed by the Modification Group.

For a full description of the original Modification Proposal as submitted by EDF Energy ('the Proposer'), please refer to the P211 Initial Written Assessment (IWA).

2.1 Current Arrangements

Under the current baseline, actions taken by the SO to balance Supply and Demand for a Settlement Period set the main Energy Imbalance Prices (System Buy Price (SBP) when the system is 'short' and System Sell Price (SSP) when the system is 'long').

The current methodology for determining system length (whether the system is 'long' or 'short') was introduced under Approved Modification P78 'Revised Definitions of System Buy Price and System Sell Price'. Overall system imbalance (i.e. Net Imbalance Volume or 'NIV') is currently determined by summing the Pre-Gate Closure trades (reflected in Balancing Services Adjustment Data or 'BSAD') with the Bids and Offers accepted by the SO. The system is 'long' when Bids and / or Relevant Balancing Services predominate and the system is 'short' when Offers and / or Relevant Balancing Services predominate.

The following information contributes to the calculation of the main Energy Imbalance Price:

- Actions taken within the Balancing Mechanism to increase the total energy on the system (Accepted Offers), or actions within the Balancing Mechanism to decrease the total energy on the system (Accepted Bids); and
- Relevant Balancing Services provided outside the Balancing Mechanism, represented via BSAD.

When the system is estimated by the method above to be short of energy, the main price (i.e. SBP as the price applied to imbalances in the same direction as the system) is based on the volume weighted average of the most expensive 500MWh of priced balancing actions[3] (accepted Offers and BSAD) remaining, following the application of the following rules:

- **De Minimis:** Individual accepted Bid and Offer Volumes below a defined threshold (currently 1 MWh) are excluded from the price calculation completely. This approach is intended to remove 'false' actions created due to the finite accuracy of the systems used to calculate Bid and Offer Volumes;
- **Arbitrage:** Accepted Bids and Offers where no net energy has been delivered to the system but which have provided an overall financial benefit to the system are excluded from the price calculation completely (i.e. where the price of an accepted Offer Volume is less than the price of an accepted Bid Volume);
- **CADL:** Acceptance Volumes associated with Acceptances of short duration (below the Continuous Acceptance Duration Limit (CADL) currently 15 minutes) are treated as un-priced[4] in the price calculation;
- **BSAD:** NGET determines whether Relevant Balancing Services will be treated as priced or un-priced. BSAD is calculated net[5] and represents both priced and un-priced Relevant Balancing Services in aggregate form;
- **Emergency Instructions:** On the determination of NGET, Accepted Bids and Offers associated with Emergency Instructions may be tagged as Excluded Emergency Acceptances and therefore treated as un-priced for the purpose of Energy Imbalance Price Calculation;
- **NIV Tagging:** Following application of the rules outlined previously, the Net Imbalance Volume (NIV) tagging process is applied to determine which of the priced actions will be subject to PAR tagging; and

These processes are collectively known as the 'tagging mechanism'. The de-minimis, CADL, emergency instructions and NIV Tagging functions are the processes to remove what are deemed to be system balancing actions from the main price.

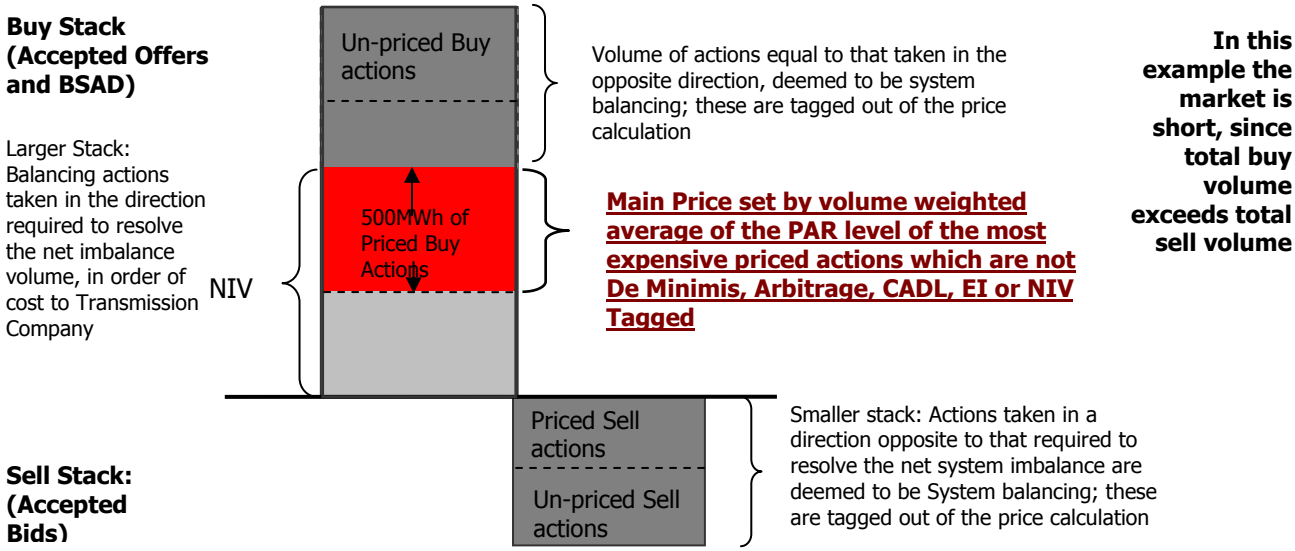
[3] This is known as the Price Average Reference (PAR) volume. PAR is currently 500MWh. When the system has excess energy (said to be 'long') then the main price (SSP) will be based on the volume weighted average of the most expensive 500MWh of priced balancing actions (accepted Bids and Energy BSAD) remaining following the application of the tagging mechanism rules. If the NIV is less than 500 MWh then no volumes will be PAR tagged.

[4] Un-priced volumes contribute to the determination of which actions set the main Energy Imbalance Price, however the costs of these actions are not included in the main Energy Imbalance Price.

[5] This means that in any Settlement Period there can only be one non-zero volume of Energy BSAD (EBVA or ESVA), and one non-zero volume of System BSAD (either SBVA or SSVA).

In addition, trades undertaken on power exchanges feed into market prices provided by Market Index Data Providers (or a single provider, as it currently stands). The reverse Energy Imbalance Price (i.e. the price applied to imbalances in the opposite direction to the system) is based on the market price derived from data submitted by Market Index Data Providers.

Figure 1. Example of the Existing Arrangements Main Imbalance Price Calculation (Short System)



2.2 Proposed Modification

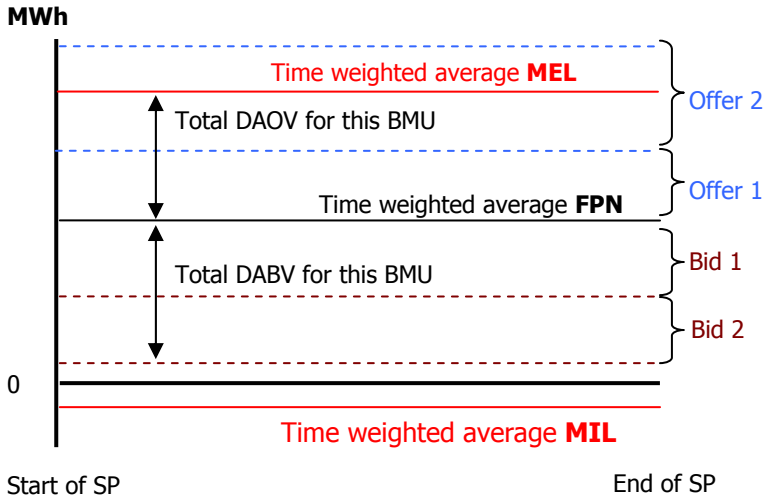
Under P211, the mechanism for calculating Energy Imbalance prices compares to the current baseline as follows:

- Rather than using actions taken within the Balancing Mechanism to increase the total energy on the system (Accepted Offers), or actions within the Balancing Mechanism to decrease the total energy on the system (Accepted Bids), the information that contributes to the calculation of the main Energy Imbalance Price in each Settlement Period will be Deemed Available Offer Volumes (DAOV) and Deemed Available Bid Volumes (DABV) for each price band for each BM Unit which submits bid-offer volumes;
- DABV and DAOV values in each period will be determined from the time weighted average Final Physical Notification (FPN) and the levels of submitted bid-offer bands capped by time weighted average Maximum Import Limit (MIL) and time weighted average Maximum Export Limit (MEL) where relevant. The FPN, MIL and MEL data are all sourced from the Grid Code and for the purposes of this Modification, the BSC will use the Grid Code definitions;
- Thus, for each BM Unit (BMU):
    - The total time weighted average DABV cannot exceed the difference between the time weighted average MIL less the time weighted average FPN;
    - The total time weighted average DAOV cannot exceed the difference between the time weighted average MEL less the time weighted average FPN; and
    - Any volumes between time weighted average MEL and time weighted average FPN plus the sum of all positive numbered offer volume intervals for that BMU or between time weighted average MIL and time weighted average FPN less the sum of all negatively numbered bid

volume intervals for that BMU shall be deemed to be 'unpriced' and will not enter the EPUS stack.

This is shown in Figure 2;

Figure 2. DAOV and DABV



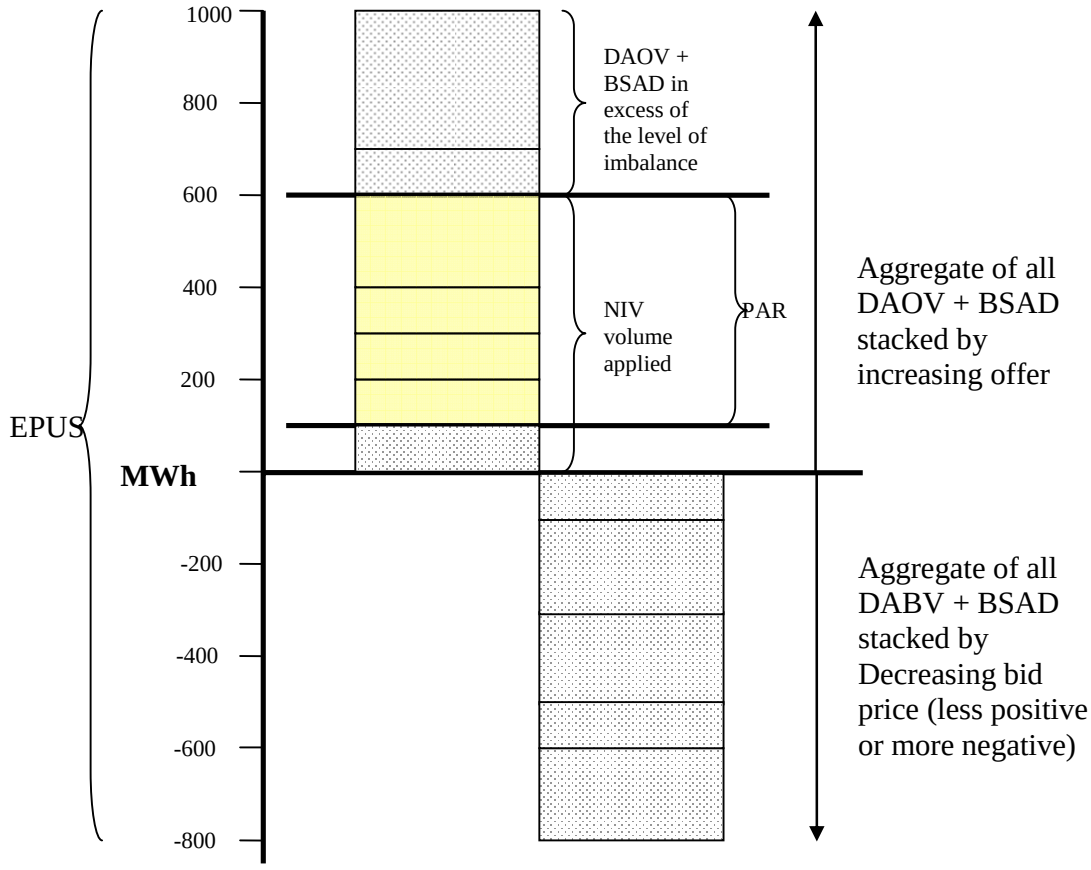
- The MIL and MEL used will be the latest available at the end of the relevant Settlement Period;
- The determination of Relevant Balancing Services provided outside the Balancing Mechanism, represented via BSAD, will not change;
- The existing process for determining whether SSP or SBP is the main Energy Imbalance Price (the existing NIV process) will not change.
- The existing process for determining the MWh size of the NIV (using accepted bids, offers and BSAD) will not change other than to remove De-minimis tagging. However, as the prices of actual acceptances making up NIV would not be used for the main Energy Imbalance Price calculation it should be noted that the existing process should be simplified as described in the P211 Requirement Specification[6].
- A new stack will be built from collating the available Bids (DABV) and Offers (DAOV) plus Energy BSAD[7]. This stack will form the Ex-Post Unconstrained Schedule (EPUS);
- De Minimis and Emergency Instruction tagging will not apply to the EPUS stack;
- EPUS Arbitrage tagging[8] will apply to the EPUS stack to remove any DAOV that are priced less than or equal to DABV. This process for EPUS Arbitrage tagging is the same as the current process for Arbitrage tagging except it is applied to the DABV and DAOV volumes instead of accepted Bid and Offer volumes;
- EPUS NIV tagging will be applied to the EPUS stack (after the EPUS Arbitrage tagging) to exclude the DABV, DAOV and BSAD that will not be required for determining the main Energy Imbalance Price such that:

[6] This includes the removal of CADL tagging, De-Minimus tagging and Emergency instruction tagging. The P211 Requirement Specification can be found here:
http://www.elexon.co.uk/ChangeImplementation/modificationprocess/modificationdocumentation/modProposalView.aspx?propID=231
[7] Energy BSAD excludes System Buy Price Volume Adjuster (SBVA) and System Sell Price Volume Adjuster (SSVA) which are not to be included in the EPUS stack.
[8] The terms 'EPUS Arbitrage tagging', 'EPUS NIV tagging' and 'EPUS PAR tagging' are used here to differentiate from the tagging that occurs in the determination of the NIV and under the main Energy Imbalance Price calculation under the current arrangements.

- When NIV is positive, starting from the least expensive, only priced buy volumes up to the volume of NIV are included; and
- When NIV is negative, starting from the least expensive, only priced sell volumes up to the volume of NIV are included.

- EPUS PAR tagging will be applied such that a volume weighted average of the PAR volume portion of the most expensive[9] priced un-(EPUS)-tagged volumes will set the main price;
- The PAR volume will not change from the existing value of 500MWh;
- Transmission Loss Multipliers will still be used in the main Imbalance Price Calculation as currently; and
- The method for calculating the reverse price will not change.

Figure 2. Example of the P211 Arrangements Main Imbalance Price Calculation when Short



2.2.1 Background to the Proposal

It has been shown that the current main Energy Imbalance Price calculation includes actions taken by the SO for reasons considered to be 'energy plus' even though a number of the current tagging mechanisms are used to try to remove some of these. Recent documentation available in support of the current tagging mechanism deficiencies has been provided in the Approved Modification P205 'Increase in PAR volume from

[9] It should be noted that 'least expensive' should, in this context, be considered in relation to the benefit of the System. Offers are bought by the System for an increase in energy, thus the 'least expensive' will be the Offer that cost the least to take. Since Bids are paid to the System by Parties for a reduction in energy, the least expensive Bid will be the one that pays the system the most. A negative Bid price will be expensive to the System, as the System is paying (rather than being paid) to reduce energy. Similarly, when using the term 'most expensive', it should be considered in this context.

100MWh to 500MWh' decision letter[10] and from within the Ofgem led Cashout Review[11]. It should be noted that some Modification Group members believe that a sufficient level of materiality of this defect has not yet been established. 'Energy plus' actions are intended to encapsulate all those actions taken by the SO for more than just energy reasons. An 'energy plus' action might be taken for energy balancing reasons, but would also include actions taken for any one or more of the following reasons:

- Frequency response;
- Reserve creation;
- Intra half-hour demand balancing (including events such as TV pickup); and
- Constraint activities (including resolving locational issues).

The Proposer suggests that P211 would remove the impact of imperfections of the tagging mechanism on the main Energy Imbalance Prices. Thus Parties would be exposed to cash out prices that are reflective of the true costs of energy balancing the system (i.e. non 'energy plus' actions) and this would more appropriately target the costs of energy balancing the system. Additionally, it is suggested that liquidity in the short term market would increase as Parties are more likely to sell volume rather than using it to self-hedge. Finally, it is believed that P211 would simplify the current BSC arrangements by making it easier for both existing Parties and new entrants to understand the imbalance pricing mechanism. It is therefore suggested that these three points have a positive impact on Applicable BSC Objective (c) "Promoting effective competition in the generation and supply of electricity, and (so far as consistent therewith) promoting such competition in the sale and purchase of electricity".

As P211 would remove much of the complex tagging mechanisms, it is also put forward by the Proposer that this simplification will positively impact Applicable BSC Objective (d), "Promoting efficiency in the implementation and administration of the balancing and settlement arrangements".

The Proposer suggests that P211 will reduce the volatility and improve the predictability of the main Energy Imbalance prices, thus reducing the incentive for Parties to take a longer position into cash out to avoid the risk of a high SBP. This will better facilitate Applicable BSC Objective (b) "the efficient, economic and co-ordinated operation of the Transmission System by the Transmission Company" by reducing the level of balancing required by the SO.

The Group discussed whether arbitrage tagging should be retained for the EPUS stack as this was not identified in the original proposal. It was agreed to include this as the Group felt that this would make the market more efficient by removing trades that would have otherwise been made prior to Gate Closure. Additionally, the Group concluded that retaining arbitrage tagging would limit the ability for price manipulation.

2.3 Potential Alternative Modification

The Group developed a potential Alternative for P211 but as yet have not been able to analyse and develop this to the extent that the majority of the Group believes it would better facilitate the Applicable BSC Objectives than the Proposed Modification. The potential Alternative is the same as the Proposed Modification described above with two changes. First, rather than using Period FPN, MIL and MEL data as described in Figure 2 above, spot values for each will be used to better represent the actual volumes

[10] Available from Ofgem's website at:
http://www.ofgem.gov.uk/Pages/MoreInformation.aspx?docid=86&refer=Markets/WhlMkts/CompandEff/CashoutRev

[11] See:
- NGET presentation to Cash Out Review ' What is the Impact of Non Exclusive Energy Actions on Imbalance Pricing', 30 March 2007;
- Cash-out Review 2007 'An Independent Perspective', Nigel Cornwall, published 22 March 2007.

Ofgem documentation of the Cash Out Review can be found at:
http://www.ofgem.gov.uk/MARKETS/WHLMKTS/COMPANDEFF/CASHOUTREV/Pages/CashoutRev.aspx

available. Secondly, an additional set of rules using dynamic parameters to modify the Bid and Offer volumes that are used to make up the EPUS stack. This is an attempt to better reflect what Bid and Offer volumes are actually 'available' to the System Operator, given that certain volumes cannot be accessed for energy balancing purposes, due to the dynamics of the plant (such as the time required to begin generating from a zero output position). There is also a second option within the potential alternative that uses Half Hourly values, and these potential rules are also included below.

For the purposes of this Potential Alternative, it is assumed that the SO can start instructing plant from Gate Closure and this is why Gate Closure is used as the starting point within these additional rules. The reason for choosing Gate Closure is because there is relative price and volume certainty at each BMU at this time. Additionally, it is at this point that the SO carries out its final assessment of its operating plan.

These rules utilising dynamic parameters can either be applied on a minute resolution basis (more accurate but potentially more complex) or using Half Hourly resolution values.

The dynamic parameter rules are:

1. DAOV and DABV qualifying rule when NDZ is greater than 89 minutes and FPN is equal to zero;
2. DAOV and DABV qualifying rule when NDZ is less than or equal to 89 minutes and FPN is equal to zero with Run Up Rate (RUR) applied;
3. Applying RUR and Run Down Rates (RDR) when FPN is not equal to zero;
4. Where FPN is less than the Stable Export Limit (SEL) at Gate Closure (broken into minute and half hourly resolution);
5. Re-pricing Bid-Offer pairs that exist between 0MWh and SEL or between 0MWh and Stable Import Limit (SIL); and
6. The minimum of MEL at Gate Closure or end of the Settlement Period should be used.

Note that the SEL, SIL, RUR and RDR data will all be sourced from data provided to the SO under the obligation in the Grid Code and, for the purposes of this potential Alternative, the BSC will use the Grid Code definitions of these parameters.

These rules are described in more detail below.

For both minute and half hour resolution:

Rule 1. DAOV and DABV qualifying rule based on NDZ > 89 minutes. This rule excludes all potential DAOV or DABV for a BMU where the Notice to Deviate from Zero (NDZ) at Gate Closure is greater than 89[12] minutes and the FPN for the Settlement Period is equal to zero for the entire Settlement Period.

This rule removes from the EPUS stack volumes that would have potentially otherwise appeared but would be considered not practical for the SO to obtain without perfect foresight prior to Gate Closure.

Rule 2. DAOV and DABV qualifying rule based on NDZ > 89 minutes NDZ, RUR and FPN = 0.

Similarly to Rule 1, this rule would remove from the EPUS stack volumes that would have potentially otherwise appeared but would be considered not possible for the SO to obtain without perfect foresight prior to Gate Closure. It was argued that this rule better reflects the physical capabilities of a generation unit to provide the MWh offered, i.e. NDZ and RUR.

[12] Note that currently Gate Closure is one hour prior to the start of the Settlement period and the Settlement Period is thirty minutes in duration. Hence cut–off is one minute less this total time, i.e. 89 minutes.

Therefore, after the application of Rule 1, by definition those remaining BMUs with an FPN equal to zero will have an NDZ at Gate Closure of less than or equal to 89 minutes. This Rule 2 then applies to all BMUs not excluded under Rule 1 but which still have an FPN equal to zero.

The Group first developed Rule 2 as described in Rule 2a below. However, the analysis for the potential alternative (presented in Figures 25 to 27 of Attachment 1) shows that for periods of system stress this could lead to extremely high prices of £1,136/MWh in Settlement Period 35 on 29 December 2005 and £20,752/MWh in Settlement Period 38 on 13 March 2006. This was caused by the application of Rule 2a which excluded units (with an FPN of zero) that were on at Gate Closure and were used by the SO to resolve the market imbalance. This is because Rule 2a takes into account the minutes notified in the NDZ from Gate Closure and then applies the ramp rates (i.e. if a unit with an FPN of zero had an NDZ of 89 minutes, then it would only start ramping 1 minute before the end of the Settlement Period).

Therefore the Group determined to modify the rule as in Rule 2b (see below) for the potential Alternative. This would start a unit ramping up from 0MWh from Gate Closure and would not apply the minutes notified in the NDZ (i.e. it was assumed that the plant was effectively warmed earlier and then synchronised at gate closure). For this reason, the analysis of this potential Alternative will only be available to industry during the first week of this consultation.

The reason for including Rule 2a here is to provide industry with the full set of information considered by the Group.

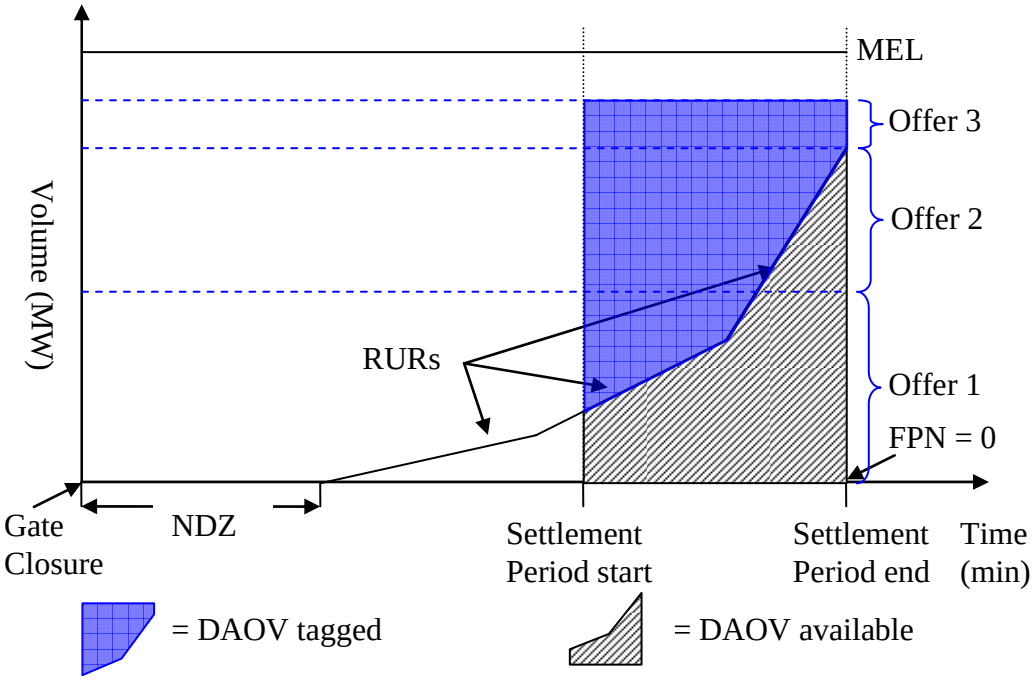
Rule 2a (Not part of the potential alternative)

When an FPN is zero at the beginning of the Settlement Period in question, and NDZ is less than or equal to 89 minutes, start profiling each BMU at a time from 'Gate Closure plus NDZ' using the declared Run Up Rates (RURs)[13]. Then the available volume (for the Settlement Period in question) below this profile can be included as DAOV (providing there are existing Bid/Offer pairs submitted for that BMU in that Settlement Period).

Rule 2a will add the time notified in the NDZ from the instant of Gate Closure to represent the expected synchronisation time of the unit. It will then profile the BMUs ramp up in generation according to the RUR supplied for the BMU[14] in the Settlement Periods from Gate Closure up until the end of the Settlement Period in question. Only DAOV that lies beneath the RUR (as determined by linear interpolation from the RURs and elbow points submitted) will be included as DAOV. The available DAOV is represented in Figure 3.

[13] This will require the RURs that are valid from Gate Closure to end of the Settlement Period in question (three Settlement Periods including the two Settlement Periods after Gate Closure but before the start of the Settlement Period in question).
[14] RUR and RDR are defined terms in the BSC. The definition is 'Has the meaning given to that term in BC1 of the Grid Code'. Note that 3 RURs or RDR can apply for any BMU within the range of 0.2-40MW per minute.

Figure 3. Rule 2a – Minute and half hourly Resolution



The DAOV that is tagged is shown as the blue shaded area in the above Figure 3 above the RUR and will not be included in the EPUS stack of P211 Potential Alternative.

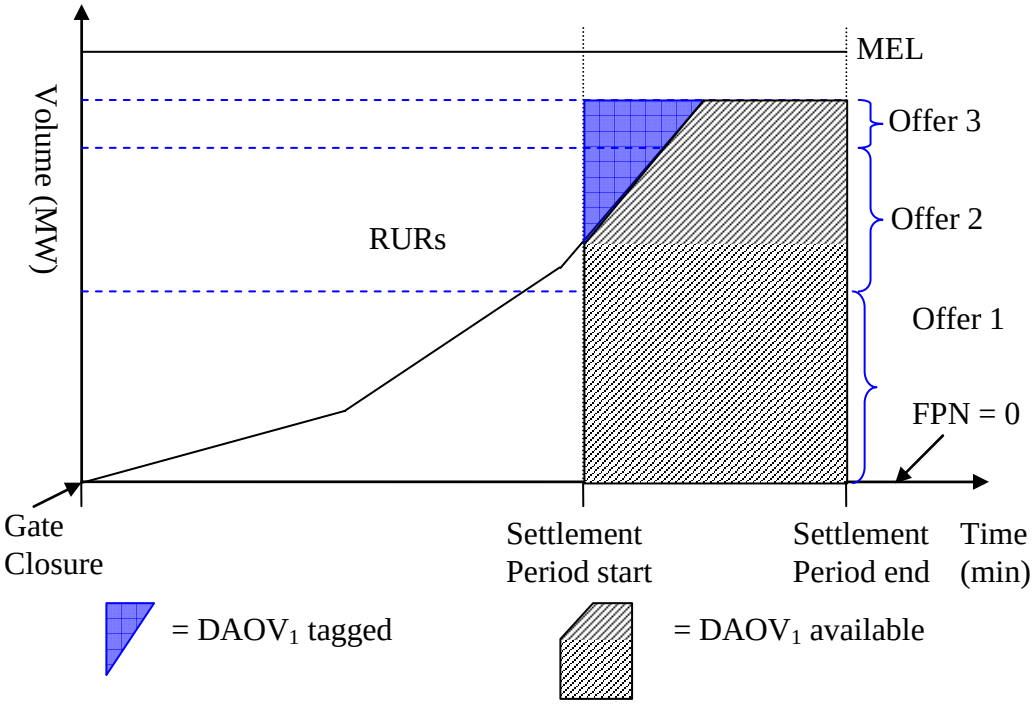
Rule 2b. (Forms part of the potential alternative)[15]

When an FPN is zero at the beginning of the Settlement Period in question, and NDZ is less than or equal to 89 minutes, start profiling each BMU at Gate Closure using the declared Run Up Rates (RURs). Then the available volume (for the Settlement Period in question) below this profile can be included as DAOV (providing there are existing Bid/Offer pairs submitted for that BMU in that Settlement Period).

Rule 2b assumes that Gate Closure represents the expected synchronisation time of the unit. It will then profile the BMUs ramp up in generation according to the RUR supplied for the BMU in the Settlement Periods from Gate Closure up until the end of the Settlement Period in question. Only DAOV that lies beneath the RUR (as determined by linear interpolation from the RURs and elbow points submitted) will be included as DAOV. The available DAOV is represented in Figure 4.

[15] Note that this means that Rule 2 could effectively be covered by Rule 3 if the condition that FPN must not equal to zero was removed. The separation of Rule 2 and Rule 3 is retained in this consultation document for clarity.

Figure 4. Rule 2b – Minute and half hourly Resolution



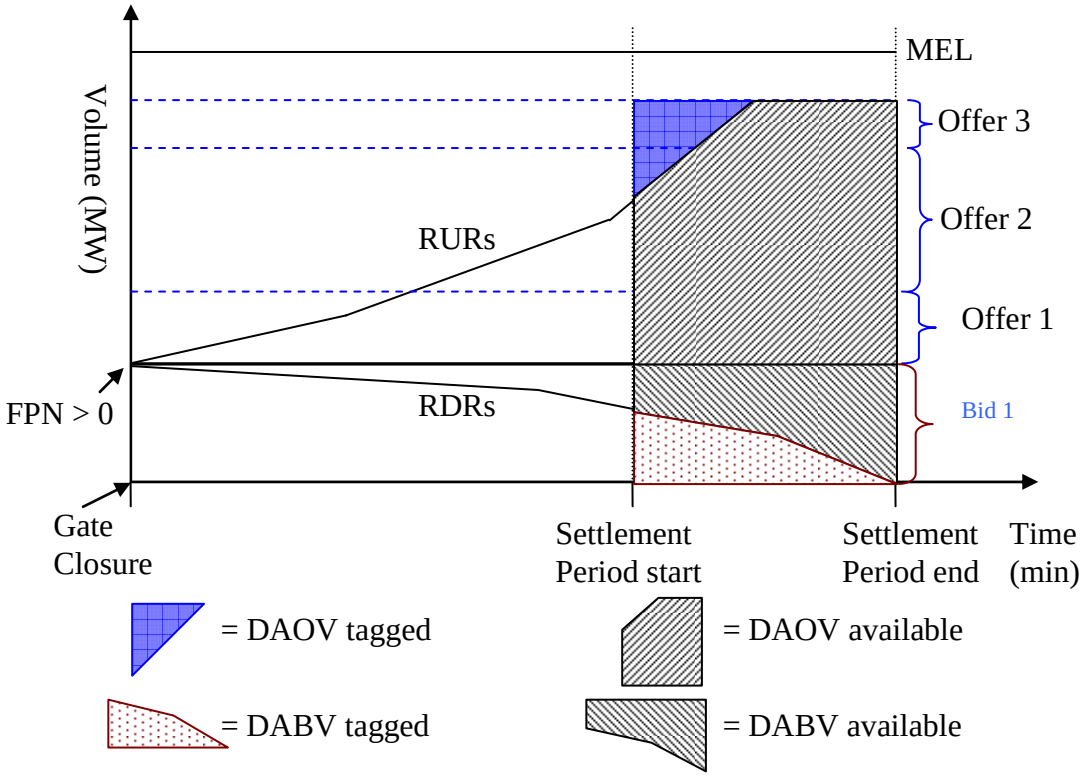
Rule 3. RUR and run down rates (FPN ≠ 0). The volume of DAOV and DABV that should be included for a BMU should be restricted by the RUR or Run Down Rates (RDR) of that BMU. If the submitted Bid/Offer pair, or a proportion of it, can be accessed from Gate Closure with the submitted ramp rates applied then this volume can be included as DAOV or DABV.

Rule 2 dealt with the special case of FPN = 0. However RURs and RDRs should be applied to all BMUs to reflect the time it takes for a unit to get to the level of its Bid or Offer. It is assumed that the SO has the foresight to request a BMU to start ramping from the instant of Gate Closure, if it is required to balance the system. Note that the BMU is considered to ramp from the FPN at Gate Closure (as opposed to any SCADA[16] snapshot of what the BMU was actually doing at Gate Closure).

The available DAOV and DABV is shown in Figure 5.

[16] Supervisory Control And Data Acquisition. SCADA systems are used for collecting real time data for what MWh a BMU is importing or exporting.

Figure 5. Rule 3 – Minute and half hourly Resolution



Similarly to Rules 1 and 2, this rule would remove from the EPUS stack any volumes that would have potentially otherwise appeared, but would be considered not possible for the SO to obtain without perfect foresight prior to Gate Closure. This rule better reflects the physical capabilities of BMUs to provide (or remove) the MWh offered (or bid).

Rule 4. Where FPN is less than SEL

Rule 4 can be applied on a minute or half-hourly resolution and was discussed by the Group. Minute resolution will represent a more accurate solution, whereas half-hour resolution is believed to be simpler to implement and understand by participants. This rule seeks to exclude any volume that would not be accessible due to a generation unit desynchronising. It reflects that once a unit is below its declared SEL at Gate Closure that the unit could not be requested to increase load again (until it can re-synchronise).

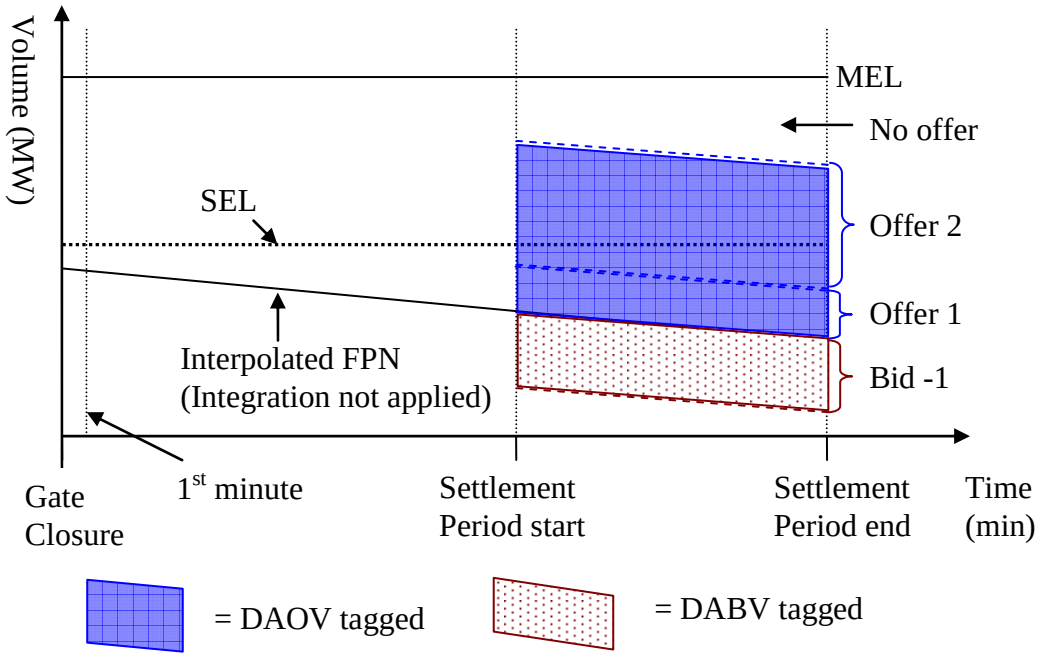
For minute resolution:

Rule 4. Where FPN is less than SEL. If a BMU is operating at less than SEL (between 0 and SEL) in the first minute past Gate Closure (for the Settlement Period in Question) indicated by the FPN[17] for that minute, and the FPN is decreasing in the SP after Gate Closure[18] (i.e. the FPN for the Settlement Period in Question is less than the FPN for the first Settlement Period past Gate closure), then no volume can be accessed for the Settlement Period in question.

This is shown in Figure 6.

[17] Use the point variable where one exists for this minute or use the point variable discovered by linear interpolation.
[18] This is to differentiate between a unit that is synchronising and desynchronising.

Figure 6. Rule 4 – Minute Resolution – FPN less than SEL at one minute past Gate Closure



For half hourly resolution:

Rule 4. Where FPN is less than SEL. If the FPN for the first Settlement Period past Gate closure (for the Settlement Period in Question) is less than SEL (that is, between 0 and SEL), and the FPN for the Settlement Period in Question is less than the FPN for the first Settlement Period past Gate closure, then no volume can be accessed for the Settlement Period in question.

In addition to the above four dynamic rules above there are two further rules that will be applied in each half hour. These are:

Rule 5. Re-pricing Bid-Offer pairs that exist between 0MWh and SEL or between 0MWh and SIL.

P211 Potential Alternative seeks to provide a proxy for the price of DAOV and DABV that exists between SEL and zero or between SIL and zero. This is because, once a BMU is dispatched within these ranges, the whole volume has to be taken by the SO, as the BMU in reality would have to run all the way to zero.

Therefore, for any Bid-Offer pairs that exists between 0MWh and SEL or between 0MWh and SIL, the price that the volume should appear as in the EPUS stack is the volume weighted average of the Bid-Offer bands below SEL (or above SIL)[19].

For the avoidance of doubt, the price associated with DAOV and DABV will be equivalent to the price submitted for the Bid-Offer pair number except where DAOV or DABV exists below SEL (or above SIL).

As a simplified example, consider period values for FPN and SEL as below. If:

FPN = 200MW

SEL = 100MW

[19] It should be noted that when FPN is between zero and SIL (negative, therefore importing) that the average of the Bids will be the volume between FPN and SIL.

Bid-Offer pair -1 (n = -1) is a 70MW band at £20/MW,

Bid-Offer pair -2 (n = - 2) is a 60MW band at £10/MW,

Bid-Offer pair -3 (n = - 3) is a 30MW band at £5/MW,

Then the average volume weighted cost for the DABV below SEL is £7.5/MW. (Given that the Bid Offer pairs run parallel to the FPN and therefore the volume below SEL is 30MW of Bid-Offer pair -2 and 30MW of Bid-Offer pair -3).

Conversely for the example where:

FPN = 10MW

SEL = 100MW

Bid-Offer pair 1 (n= 1) is a 70MW band at £10/MW,

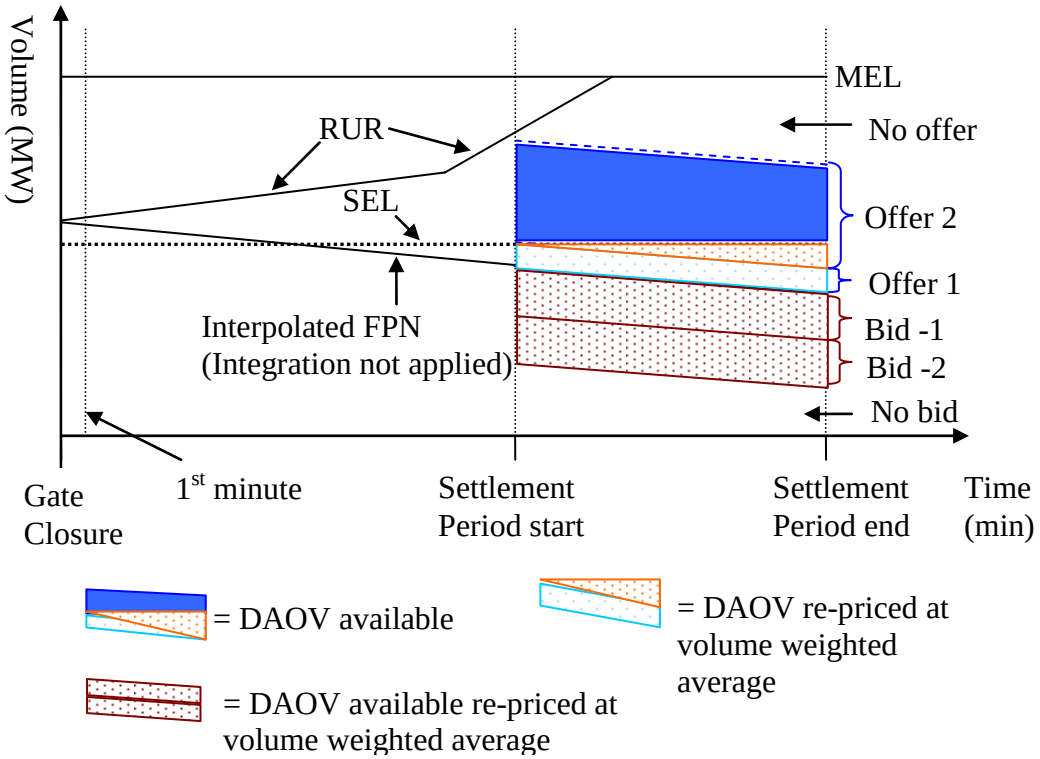
Bid-Offer pair 2 (n = 2) is a 60MW band at £20/MW,

Bid-Offer pair 3 (n = 3) is a 30MW band at £25/MW,

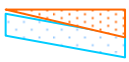
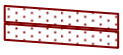
Then the average volume weighted cost for the DAOV between FPN and SEL is £12.2/MW. (Given that the Bid Offer pairs run parallel to the FPN and therefore the volume below SEL is 70MW of Bid-Offer pair 1 and 20MW of Bid-Offer pair 2).

The concept of this Rule 5 can also be shown in Figure 7 below.

Figure 7. Rule 5 – Minute Resolution – FPN greater than or equal to SEL at one minute past Gate Closure



Where:

- the DAOV below SEL represented by the area  should be priced at the volume weighted average price of the DAOV in this area; and
- the DABV below SEL represented by the area  should be priced at the volume weighted average price of the DABV in this area.

Rule 6. Minimum of MEL at Gate Closure or end of the Settlement Period.

The MEL used for each BMU in each Settlement Period will be the lower of the MEL submitted by and existing at Gate Closure or the MEL declared before the end of the Settlement Period.

This rule will remove the possibility of Parties changing MEL after Gate Closure for any potential gain[20].

Note that the MIL used will be the latest available at the end of the relevant Settlement Period.

3 AREAS RAISED BY THE TERMS OF REFERENCE

This section outlines the initial conclusions of the Modification Group (the 'Group') regarding the areas set out in the P211 Terms of Reference. This covers the following areas:

- Derivation of the Ex-Post Unconstrained Schedule;
- Impact on Energy Imbalance Prices;
- Cashflow Analysis;
- Incentives;
- Impact on Settlement;
- Default Rules; and
- Implementation.

3.1 Derivation of the Ex-Post Unconstrained Schedule

3.1.1 The effect of dynamic parameters

Under the Proposed Solution, the derivation of the EPUS was well defined. This definition specifically excludes the consideration of any dynamic parameters. The Proposer suggested that the inclusion of dynamic parameters could potentially overcomplicate the solution and necessitate the inclusion of assumptions that could exclude volumes that might have actually been available to the SO. For the Proposed solution, the only limitation for Bids and Offers submitted by Parties to enter the EPUS stack is the capping by time weighted MIL and time weighted MEL.

The majority of the Group considered that this Proposed Solution would not be representative of what was actually available to the SO to use given the various real time and dynamic constraints they operate under. The majority of the Group therefore preferred a potential Alternative that incorporates some element of dynamic parameters that reflected those imposed on the SO when balancing the system. The effect that including the dynamic parameters as drafted for the potential Alternative (but including Rule 2a) is shown in Attachment 1 (Figure 28) for 29 December 2005. This shows that including the set of dynamic parameters (with Rule 2a) led to an average 55% reduction in the size of the DAOV stack and a 13% decrease in the size of the DABV stack.

Additionally some Group members felt that the set of rules in the potential Alternative still did not represent the full set of constraints applicable to the SO. This is because the potential Alternative looks at each Settlement Period in isolation. The SO however has to take a wider view across a number of Settlement Periods. For example, if a unit is required only for 1 hour of the peak but has a minimum non-zero time (MNZT) of 4 hours then the SO has to bring that unit on for the full 4 hours or not at all.

[20] Note that Grid Code provisions BC1.4.2 (a), (c) and (e) refer to Parties obligations for submitting physical and dynamic data.

One group member noted however that the current cash out rules do not try to re-create the physical system as certain trades are removed. The Proposed and the potential Alternative are simply different ways of providing a proxy for the cost of energy imbalance.

The impact of including and excluding dynamic parameters is also represented by the price differentials that are discussed in Section 3.2 below.

How Balancing Services Adjustment Data (BSAD) would enter the EPUS was also discussed by the Group. The Proposed solution was clear that the methodology for calculating BSAD should not change and that this would enter the EPUS stack at the price and in the manner that BSAD is currently determined.

Some Group members felt that this was not consistent with the concept of the Proposed solution to include actions taken for energy only reasons (and therefore not 'energy plus') due to the fact that BSAD includes contracts procured by the SO and these might include services such as reserve provision. The SO currently decides which items are included in BSAD by determining whether the actions are considered for 'energy' or 'system' purposes (see BSAD Methodology Statement[21]). Also, the Group noted that BSAD included actual buy and sell volumes 'accepted' by the SO whereas the EPUS was based on offers/bids 'available' to the SO. However, the Group recognised that reviewing the calculation of BSAD for the purposes of this Modification is outside the scope of the BSC and agreed to note this point in their assessment.

The Group also considered the application of De-Minimis Bids and Offers in the EPUS stack. It was noted that the current practice of removing Bids or Offers of 1MWh or less is used to remove 'false' actions created due to the finite accuracy of the SO and BSC Systems. However, the Group did not believe this to be a substantial issue due to the nature of the size of De-Minimis volumes. Thus the Group believed that, in line with the principle of the Modification to include all submitted Bids and Offers in an EPUS, that the De-Minimis tagging rule should be removed from the NIV calculation and also no De-Minimis tagging would be applied when constructing the EPUS.

3.1.2 Other Markets

The Group investigated the Single Electricity Market (SEM) in Ireland and the Australian Electricity Pool that were identified as using an EPUS based approach. The similarities and differences between the BSC arrangements and those in the other markets were identified. The Group noted that there were no other markets identified that would have a similar arrangement as that of the Proposed or potential Alternative. That is, there are no markets that use an ex-post unconstrained schedule for calculating imbalance prices.

3.1.2.1 Irish Market

The SEM in Ireland was due to go live in July 2007 but this has been delayed. This will be a central commitment market with a single clearing price for each trading period and an explicit capacity payment mechanism. This single price will be set ex-post on an unconstrained (in terms of network constraints but not generator constraints) basis[22]. The SEM will have a single system marginal price (SMP) that is set for each half hour, based on an ex post optimised schedule for the whole trading day.

The ex-post SMP for each half hour trading period will be based on an unconstrained stack of available generation optimised over the 'optimisation time horizon' which runs from 6am on the trading day until (but not including) midday on the day after the trading day. The optimisation takes into account the plant on the system at the end of the previous trading day as well as the actual demand and renewable generation which occurred during that trading day.

A SMP is produced for each half hour trading period. Uplift is applied to the SMP to ensure that energy prices should reflect underlying market dynamics. The purpose of the uplift is to ensure that the production cost for each generator is recovered through the SMP within that period of operation in the optimisation time

[21] Available on National Grid's website at http://www.nationalgrid.com/uk/Electricity/Balancing/transmissionlicensestatements/BSAD/
[22] Constrained on and constrained off payments will be made to participants in well defined circumstances.

horizon. A price cap and price floor is set by the regulator from time to time, and is applied if the software calculates SMP outside these limits.

A full set of all available dynamics considered was not available. However, the current draft of the rules highlights the following areas. The objective of each price calculation run is to minimise the aggregate sum of schedule production costs over the optimisation time horizon subject to:

a) Scheduling generation to meet demand in each trading period within the optimisation time horizon;

b) Scheduling each generation unit to be at an output level between its minimum and its availability; and

c) Schedule each generation unit within its technical capabilities including (but not limited to) its minimum stable limit, ramp rates, and minimum on and off time. Additionally, consideration is given to restarting a unit if it is to be taken off.

The Group noted that there was a fundamental difference between the SEM and the BSC arrangements in that the SEM is optimised over an entire day and uses an ex-post unconstrained schedule with a full set of dynamic parameters. Additionally, SEM final prices will be published significantly later after the Settlement Period (4 days after the trading day although indicative prices are available earlier) and thus prompt pricing signals would be lost. Finally, the Group noted that the move toward an EPUS solution in the SEM has been part of substantial change in that market that has been subject to much consideration and developed over a long period of time.

3.1.2.2 Australian market

The National Electricity Market (NEM) in Australia is a physical energy only spot market traded through a gross pool in which 'spot' prices are produced for every five minute period. A complex linear program produces a dispatch instruction for each unit every five minutes and also produces location based prices. Prices are calculated at the marginal price although these are capped at A$10,000/MWh. The Group concluded that the market was significantly different from the BSC arrangements. The NEM does not have any imbalance cash out mechanism unlike the BSC and does not use an EPUS. Therefore, it was not considered comparable for this Modification.

3.1.2.3 Historical Pool arrangements

How an unconstrained Schedule was used under the pre NETA arrangements (the Pool) was also discussed by the Group. However, the Group noted that the Irish SEM was partly based on the arrangement under the Pool and felt that the same considerations also applied to the Pool. Therefore, it was not considered useful for the assessment for this Modification.

The Group noted the operation of an EPUS in other markets but did not conclude that there are any significant benefits or parallels that they felt could be used in the solutions for P211 Proposed and potential Alternative or in the Group's assessment thereof.

3.2 Impact on Energy Imbalance Prices

3.2.1 Evaluating the Defect

It is suggested by the Proposer that the Energy Imbalance Prices under the current arrangements are impacted by imperfections in the tagging mechanism (further details are contained in Attachment 2 – Proposer's Presentation). This is considered to be a concern due to the negative impacts of exposing Parties to cash out prices that are not reflective of the true cost of energy balancing of the system. The Proposer confirmed that his definition of "system balancing actions" includes any action that has a dual purpose (i.e. the action was not taken purely for the purpose of the resolution of Half Hourly energy imbalance).

The Proposer has provided some further analysis to supplement the information already in the public domain (as noted in section 2.2 above) on the degree to which system balancing actions enter Energy Imbalance Prices under the existing arrangements (See Attachment 3). The Proposer noted that it is difficult to assess the degree of the defect as only the SO can say why any individual action was taken. However, the Proposer suggests that Bids or Offers taken out of merit order is a good indication that an action is 'energy plus'. Additionally it is suggested that where SSP in a long market falls significantly below the cost of generation (and of other, unaccepted, Bids present at that time), that this also provides likely evidence of the defect.

The Proposer provided an example of a specific Settlement Period (SP 19 on 26 September 2005) in which the buy and sell stacks were analysed. This was when the SO took actions to resolve an export constraint in Scotland. These actions also had the effect of reducing the supply/demand imbalance. The Proposer notes that there were no opposing actions to 'tag' out the accepted constraint actions. This therefore represents one Settlement Period in which constraint activity was shown to impact Energy Imbalance Prices.

One member noted that the strongest examples of constraint activity affecting Energy imbalance Prices were concentrated in a period not long after the start of the British Electricity Trading and Transmission Arrangements (BETTA) in April 2005.

Some Group members noted this occurrence and noted further examples may have occurred since BETTA go live but did not feel it has been proven to be a significant issue.

The Group have considered the extent to which the current Energy Imbalance Prices reflect the true energy costs of the SO balancing the system. However, the Group noted that this would not be an easy exercise due to the difficulty in working out whether each action taken by the SO should be included, or not, in the Energy Imbalance Price calculation. Furthermore, for any action considered to be 'energy plus', a portion of that action could have been required for energy purposes by the SO. Therefore, this portion should theoretically be included in an Energy Imbalance Price that is not impacted by tagging imperfections.

The Group considered that determining an Energy Imbalance Price that reflects the true energy costs of the SO balancing the system would be too difficult to do on any large scale, because each Settlement Period would have to be scrutinised in detail. Furthermore, when scrutinising each action, there would need to be a potentially subjective method by which each action taken by the SO can be categorised as one that should, partially should, or should not be included in Energy Imbalance Prices. This applies equally to the Proposed as to the potential Alternative Modification.

Some Group members expressed the view that the overall objective of any cash out regime, is that the cash out prices should be a proxy of the short term costs of the SO in balancing the system. The cash out prices should reflect the opportunity costs of energy balancing. Therefore, any solution should ensure that the BSC arrangements do not move away from reflecting the costs faced by the SO in energy balancing.

Whilst there was a unanimous view that a defect has been shown to exist in certain Settlement Periods, some Group members were still not satisfied that evidence proving significant materiality of the defect existed.

3.2.2 Recalculated Energy imbalance prices

The Modification Group considered the analysis illustrating the difference between the Energy Imbalance Prices calculated under the current baseline and those of the Proposed Solution. The analysis is included as Section 2 of Attachment 1. On consideration of this analysis the Group noted that:

- The P211 Proposed prices are only directly comparable with the current live prices after 2 November 2006 in which PAR500 was introduced. (Prior to this a volume weighted average price of balancing actions not removed via the Tagging Mechanisms was used and thus prices were by definition equal to or lower than a PAR500 price). For the period 2 November 2006 until 31 March 2007:

- When the system was short, the P211 Proposed SBP was on average £10.25/MWh (or 16%) lower than the current arrangements (with a maximum decrease of £193/MWh);
- When the system was long, the P211 Proposed SSP was on average £1.20/MWh (or 7%) higher than the current arrangements (with a maximum increase of £20.50/MWh);
- There were 258 out of 7,197 Settlement Periods in which either P211 SBP was greater than the current arrangements or P211 SSP was less than the current arrangements. The Group identified three Settlement Periods (SP 1 to 3) on 2 September 2005 (See Figure 13 in Attachment 1) in which this was the case. The reason for this is that NIV was very small and negative (so the system was long and SSP was the main Energy Imbalance Price). P211 SSP is higher than PAR500 SSP as expected intuitively. P211 SSP is also higher than the market price. Therefore, P211 SBP defaulted to P211 SSP (as defined in the BSC, T4.4.6(b)) and this caused P211 SBP to be higher than PAR500 SBP.

- Recalculated Prices for known periods of constraint activity (2 September 2005 and 18-20 October 2005) and also for periods of system stress (29 December 2005 - Notice of Inadequate Margin (NISM) notice issued, 13 March 2006 – Gas Balancing Alert (GBA), and 18 July 2006 – High Risk of Demand Reduction (HRDR) notice issued), can be seen in Attachment 1 (Figures 13 to 19).
- Indicative prices[23] for the potential option that included Rule 2a are only available for the Periods of constraint activity and system stress noted above. These can be seen in Figures 21 to 27 of Attachment 1. Indicative prices for the potential Alternative that included Rule 2b had not been calculated at the time of publication of this document. These should be available on Friday 17 August 2007 although it should be noted that the Modification Group will not have reviewed or commented upon this data.

Therefore, the Group concluded that there is, on average, a divergence between the Energy Imbalance prices calculated from the current arrangements and those calculated under P211 Proposed. The Group noted that this divergence appeared to be more substantial in periods of system stress. However, without any benchmark for where an optimal price (without any tagging imperfections) would lie (and acknowledging that this was unlikely to be achievable), the Group could not conclude whether the P211 Proposed or potential Alternative were better estimates of the true energy costs of the SO balancing the system than the current arrangements. The Proposer noted that it was their belief that a benchmark for an optimal price did exist, particularly in periods where the SO had identified that constraints had impacted imbalance prices. In these periods, both the Proposal and potential Alternative produced similar prices that better represented the cost of energy imbalance.

3.3 Cashflow Analysis

For otherwise identical conditions, the Group believe that P211 Proposed will generally decrease Energy Imbalance Prices as compared to the current baseline and have done so (on average) throughout the whole period of analysis conducted. It therefore follows that under otherwise identical conditions, P211 Proposed will decrease the Residual Cashflow Reallocation Cashflow (RCRC). However, if the prices are lower and this leads to less incentive to balance, this may result in upward pressure on RCRC. The impact on RCRC in otherwise identical conditions for the Proposed solution can be seen in Figure 20 of Attachment 1.

Some members of the Group noted under P136 'Marginal Definition of the 'main' Energy Imbalance Price', P137 'Revised Calculation of System Buy Price and System Sell Price' and P194 'Revised Definition of the Main Energy imbalance Price', the impacts of RCRC on incentives to balance had been well documented. It was those members belief that analysing RCRC could be considered of little value as it is a side effect to the Settlement calculations. The Settlement calculations can produce unpredictable prices as the relative sizes of

[23] Due to time restrictions, the prices are indicative only because they do not have Rule 4 and Rule 6 applied. Additionally, the modelling has not been verified and tested.

SBP and SSP could lead to the RCRC being either a debit or a credit. The inability to predict RCRC means that it would have little or not influence on Parties incentives and will not cause any change in their behaviour. Therefore those members concluded that RCRC does not distort the incentive to balance provided by Energy Imbalance Prices.

3.4 Incentives

The Group noted that under identical conditions, because the P211 Proposed solution prices are on average weaker, those Parties exposed to Energy Imbalance prices would be the same or less liable (on average) to Energy Imbalance Charges as compared to the current baseline. Therefore it was noted that P211 proposed would provide less incentive to avoid being in imbalance in the same direction of the system. However, some members felt that because the prices would be more cost reflective that this would decrease the likelihood of Parties being consistently long (to avoid what in their view might be penal SBP). Thus this would create greater incentives to balance by being less long. One Group member noted that whilst on average there is a tendency for parties to be long, that there is also evidence that Parties are short during peak stress periods. Some members of the Group noted that Parties make rational decisions based on the opportunity cost of being in imbalance (i.e. the forward price). The fact that Parties are long on average reflects the asymmetric risks associated with being long compared to being short. SBP is more volatile and thus it should be expected that it would be rational for Parties to be more likely to be long than short. For Parties to be balanced on average, this would assume identical risks and symmetrical bid and offer curves, which is not a likely outcome under either P211 or of the current baseline.

Some members of the Group recognised that there would be a step change in Parties trading strategies that would be likely to occur with the introduction of a P211 Proposed or potential Alternative solution and that these strategies would be developed over time. This would be based on rational decisions that arise from the incentives faced by Parties and whether it would be more beneficial to go into imbalance or trade out their positions in the forward market. The Proposer believed that the majority of the time the incentives will be the same as currently exists to ensure that people balance.

Some members believed that the current arrangements are predictable and volatile. Predictable because if you are aware that an expensive generator is being warmed to provide peak generation then you can expect to see a high and potentially volatile Energy Imbalance Price that reflects the costs to the SO of accepting an offer from that unit. It was the view of those members that the P211 Proposed solution would reduce the volatility and also create a situation where it would no longer be predicable that having a high priced unit on (for whatever reason) will actually lead to a high Energy Imbalance Price. Without volatility, trading opportunities are lost and there is reduced incentive for a Party to trade out its imbalance. A minority of the Group disagreed that volatility would be significantly reduced highlighting that the recalculated prices (seen in Attachment 1 – particularly Figures 18 and 19) still display elements of volatility and price increases during peak demand periods.

Additionally, some Group members believed that the P211 Proposed solution will lead to a greater amount of actions having to be taken by the SO because the feedback loop to the SO costs to balance the system have been removed, thus reducing cost reflectivity and reducing the incentive to balance. This in turn increases the SO costs which, as the P211 Imbalance Price was unlikely to reflect the SO's costs, would not be targeted to those Parties who are out of balance.

The Group noted that the exclusion of dynamic parameters in the Proposed solution provides a set of rules in which Parties' legitimate behaviour can affect prices. The main concern raised was that Bids or Offers would be included in the EPUS stack even if their dynamics prevented the SO from using them in reality. This would have the effect of unduly suppressing imbalance prices leading to an inappropriate reduction in incentives for Parties to balance. This issue was of most concern under the original modification, but could also be an issue under the potential Alternative.

Another concern was that Parties may seek to influence prices. An example would be where a Party re-submits prices for a BMU that cannot be accessed by the SO due to either ramp rates or NDZ. Whilst the BMU would effectively be excluded (by the dynamics) from being accepted in the balancing mechanism (from being paid at its Bid price) it could still be used by that Party to make cash out prices unduly low if the BMU were priced so low as to fall within the EPUS stack. It was argued by some members that Parties might seek to reduce the main Energy Imbalance Price to their advantage. One member noted that any behaviour of this nature by Parties could be in breach of the FSA's market abuse rules, since this would be distorting the market (cash out prices are an important applied index, and can affect forward prices) and could also be viewed as a "manipulating device" under the changes to the Market Abuse Regime that were brought in under the Market Abuse Directive. The FSA has in place a formal Concordat whereby it can exchange data freely with Ofgem. However, it was noted by the Group that because of the numerous actions taken by numerous Parties every day that it could be a very difficult exercise to identify and then prove, any anti-competitive behaviour. To provide some data volume context to this issue, there are approximately 200 active BMU in the balancing mechanism, all of whom have the ability to submit 5 Offer and 5 Bid price pairs per Settlement Period. These prices can be resubmitted by the BMU for every Settlement Period in the day. Therefore the number of prices that would potentially have to be scrutinised on a daily basis is 48*200*10 = 96,000 prices. Each of these prices may have been resubmitted several times in one day.

A number of Group members believe that the Proposed and (to a lesser extent) the potential Alternative solutions do not reflect the costs of post Gate Closure plant loss. Parties who have plant that would receive a depressed signal as potentially very expensive short term actions taken to alleviate the trip would be lost from the calculation.

These group members also felt that there could be a reduced incentive for Parties to trade out the imbalance created by such plant failures given that the Energy Imbalance Prices would be less material than at present, being set based on submitted bids and offers (DAOV and DABV) rather than potentially very expensive actions that would be taken in such short timescales. This would also decrease the long term incentive on Parties to maintain their plant to ensure an efficient level of plant reliability. Less reliable plant would create greater potential for future plant failure and would increase the costs for the SO to balance the system. A Group member noted that this would also lead to long term security of supply issues.

The Group as a whole noted that although Parties face uncertainty as to whether the overall imbalance of the system will be long or short, the incentive for Parties to be in imbalance in the opposite direction to the overall imbalance of the system will remain unchanged (since the derivation of the market price will be the same).

3.5 Impact on Settlement

The requirement to build an EPUS stack of all DAOV and all DABV for every Settlement Period would be a significant increase to the amount of computation required by the BSC Central Systems. This would have a potentially large impact on the ability for prompt prices to be produced within current timescales.

The Group agreed that it may be inefficient to require BMRA and SAA to calculate MIL, MEL, DAOV and DABV for all BM Units, when many of these values will then be EPUS NIV Tagged (and hence have no impact on Energy Imbalance Prices). This would be a particular concern in the context of BMRS, where prompt price reporting is of the essence. This issue was addressed by only requiring the BMRA and SAA to build enough of the DAOV/DABV stack to calculate Energy Imbalance Prices (i.e. allow them to start building the stack with the cheapest Bids and Offers, and to stop when a sufficient volume of stack has been constructed in order to complete EPUS Arbitrage tagging and then ensure that all remaining DAOV and DABV volumes would be NIV tagged).

In doing so it has been confirmed that the P211 Proposed Solution would not have any detrimental impact on prompt prices.

Views are being sought from Parties on whether the above approach of only building enough of the DAOV/DABV stack to calculate Energy Imbalance Prices would be acceptable (given that it would prevent the reporting of MIL, MEL, DAOV and DABV for those Bids and Offers that were wholly EPUS NIV Tagged).

The P211 potential Alternative does require more computation to apply the additional set of dynamic parameters. To ensure that this has no impact on prompt prices this would require additional investment of £23,000. There are two options for implementing the potential Alternative. One in which the DAOV and DABV that is tagged is reported after the set of dynamic rules is applied and then also reported after each step of EPUS Arbitrage tagging, EPUS NIV tagging and EPUS PAR tagging. A potentially more cost effective solution is to not report the DAOV and DABV tagged after the application of the dynamic rules. Thus only the total DAOV and DABV tagged would be reported. See section 3.7 for more details on these reporting costs.

3.6 Default Rules

The Proposer suggested that the default rules may require review. Therefore the Group undertook to identify the likelihood of there being insufficient volume in the EPUS to resolve the NIV. The analysis of the EPUS stacks identified that there is normally substantial volumes of DAOV and DABV to resolve NIV. This is included in the analysis in Figure 1 and Table 1 of Attachment 1 where the lowest margin between the EPUS stack and NIV was 1,249MW in Settlement Period 33 on the High Risk of Demand Reduction (HRDR) day of 18 July 2006.

The Group noted that a default rule is still required in the event that NIV exceeded the volume in the EPUS stack[24]. The Group agreed to retain the existing rules such that in the event of not enough EPUS volume, the main Energy Imbalance Price will be the volume weighted average of the most expensive DAOV or DABV that is available[25] (whilst also remaining subject to the existing set of default rules).

3.7 Implementation Approach and Costs

3.7.1 Modification Group's Initial Discussions

The Modification Group has identified indicative costs and implementation lead times for P211 Proposed and P211 potential Alternative.

Two options were identified for implementing the P211 Proposed and potential Alternative solutions based on the level of involvement of the Transmission Company in producing either the raw data to BSC Central Systems or producing the EPUS stack or the Energy Imbalance prices and providing these to BSC Central Systems.

The Transmission Company was therefore requested to provide an estimate of the development, capital and operating costs (broken down in reasonable detail) which the Transmission Company anticipates that it would incur in, and as a result of, implementing the Proposed Modification if the Transmission Company were also to produce:

a) Providing the raw data to BSC Central Systems (no change from current arrangements);

b) the EPUS stack (as defined in section 2.1-2.4 of the P211 Requirement Specification), after the application of EPUS Arbitrage Tagging, required to resolve NIV and provide this to BSC Central systems; or

c) the main Energy Imbalance Price as derived in the P211 Requirement Specification (section 2) and provide this to BSC Central systems (BMRA) such as to enable prompt price reporting in the same (or similar) timescales as present.

[24] Although the Group did not conclude whether such a scenario could occur.
[25] For example, if NIV is 500MWh and the amount of DAOV is 400MWh then the price is calculated from the volume weighted average of the 400MWh of DAOV.

Two estimates for the changes to BSC Central Systems were therefore provided:

d) Producing the main Energy Imbalance Price based; or

e) Publishing the main Energy Imbalance Price as provided by the Transmission Company or producing and publishing the main Energy Imbalance Price based on the EPUS stack provided by the Transmission Company.

The Transmission Company indicated that to provide the requested estimates for (b) and (c) above would be a significant piece of work and they regrettably could therefore not provide any meaningful estimates within the timeframe of the Assessment of P211.

On getting the costs for changes to the BSC Central Systems, the Group noted that the savings in costs for having the Transmission Company produce the Main Energy Imbalance prices or the EPUS stack was £35,000. Given the indication of the Transmission Company above, the Group agreed that there was no value in pursuing options (b) or (c) above as the work required to implement the solution (as well as resource required to produce the estimates) by the Transmission Company would not have been under £35,000.

3.7.2 Results of Proposed Modification Impact Assessment

Option (d) PROPOSED MODIFICATION IMPLEMENTATION COSTS[26]

		Stand Alone Cost	Tolerance
Service Provider[27] Cost			
	Change Specific Cost	£ 133,650	+/- 0%
	Release Cost	£ 51,850	+/- 0%
	Total Service Provider Cost	£ 185,500	+/- 0%
Implementation Cost			
	External Audit	£ 0	+/- 0%
	Design Clarifications	£ 9,275	+/- 0%
	Additional Resource Costs	£ 0	+/- 0%
	Additional Testing and Audit Support Costs	£ 5,000	+/-20%
	TOMAS changes	£ 50,000	+/-20%
Total Demand Led Implementation Cost		£ 249,775	+/- 10%

[26] An explanation of the cost terms used in this section can be found on the BSC Website at the following link: http://www.elexon.co.uk/documents/Change_and_Implementation/Modifications_Process_-_Related_Documents/Clarification_of_Costs_in_Modification_Procedure_Reports.pdf

[27] BSC Agent and non-BSC Agent Service Provider and software costs.

Port and Migrate Costs

Service Provider Cost	Port and Migrate[28]	£ 45,000	+/- 0%

ELEXON Implementation Resource Cost		231 man days £ 50,820	+/- 5%
Total Implementation Cost		£ 345,595	+/- 20%

Note that for Option (e) the only difference is to the Total Service Provider Cost (and Total Implementation Cost) which would be £150,500 (and £310,595 respectively). That is, a difference of £35,000.

3.7.3 Results of Potential Alternative Modification Impact Assessment

This IA identifies two options for Reporting; A reduced reporting option and a detailed reporting option (as discussed in 3.5).

Option (d) Potential Alternative MODIFICATION IMPLEMENTATION COSTS

		Stand Alone Cost	Tolerance
Service Provider Cost			
	Change Specific Cost Reduced Reporting	£ 194,800	+/- 0%
	Change Specific Cost Detailed Reporting	£ 204,150	+/- 0%
	Release Cost	£ 51,850	+/- 0%
	Total Service Provider Cost (reduced reporting)	£ 246,650	+/- 0%
	Total Service Provider Cost (detailed reporting)	£ 256,000	+/- 0%
Implementation Cost			
	External Audit	£ 0	+/- 0%
	Design Clarifications (reduced reporting)	£ 8950	+/- 0%
	Additional Resource Costs	£ 0	+/- 0%

[28] The Port and Migrate costs are an indicative cost related to Project Isis interaction. This cost covers the porting and migrating of the P211 changes from Tru-64 and Oracle 9i to HP-UX and Oracle 10g. This cost assumes that LogicaCMG is doing all calculations and also it is assumed that this work follows the main CVA Port and Migrate project. Note that the optional BMRA reporting was ignored for this indicative cost

	Additional Testing and Audit Support Costs TOMAS changes	£ 5000 £ 79,310	+/-20% +/-20%
Total Demand Led Implementation Cost (reduced reporting)		£ 339,910	+/- 10%
Total Demand Led Implementation Cost (detailed reporting)		£ 349,260	+/- 10%

Port and Migrate Costs

Service Provider Cost	Port and Migrate	£ 50,000	+/- 0%

ELEXON Implementation Resource Cost		Reduced Reporting: 259 man days £ 56,980 Detailed Reporting 315 man days £ 69,300	+/- 5%
Total Implementation Cost Reduced Reporting		£ 435,590	+/- 20%
Total Implementation Cost Reduced Reporting		£ 454,960	+/- 20%

Implementation Approach for Proposed and Potential Alternative:

Due to the size of the changes required for P211 Proposed Modification it is recommended that P211 should form a complete Release on its own; no P211 cost benefits would be derived from the inclusion of other Change Proposals or Modifications in the same release as P211 (although there may be cost benefits for the other items included).

a) BSC Agent Impact

Work required includes:

- Expand BMRA and SAA Settlement data checking functions to include MIL/MEL data.
- Defining a new database table to hold DAOV and DABV data.
- Modifying the F009 functionality to include P211 functionality for P211 effective Settlement Dates.

For SAA reporting, a new DTC version of the SAA-I014 flow will be defined. The SAA-I014 module will be modified so that for P211 effective Settlement Dates additional data reporting will be included in the report. Where a Bid-Offer Pair has associated DAOV or DABV data defined by the Settlement Calculation Process

then this data will be reported against the Bid-Offer Pair. Some existing fields will not be reported for post-P211 dates as they will no longer be relevant.

The lead time is 26 weeks and all prices assume a November 2008 target release.

b) Transmission Company Impact

The Transmission Company will be required to modify systems receiving SAA data and business processes to cope with the new SAA-I14 variables. The initial cost estimate for implementing this P211 Proposed is approximately £80K with a lead time of approximately 7 months.

c) BSCCo Impact

ELEXON acceptance testing (4 weeks), new service provide acceptance testing (4 weeks) and go-live decision and deployment (2 weeks) will take a total of 10 weeks from the conclusion of the changes to the BSC Central Systems identified above (26 weeks). It is therefore proposed the Implementation Date for Proposed Modification P211 should be 6 November 2008 if an Authority decision is received on or before 28 February 2008, or 25 June 2009 if the Authority decision is received after 28 February 2008 but on or before 16 October 2008.

Due to the size of the changes required for P211 Proposed Modification it is recommended that P211 should form a complete Release on its own; no P211 cost benefits would be derived from the inclusion of other Change Proposals or Modifications in the same release as P211 (although there may be cost benefits for the other items included).

4 ASSESSMENT OF MODIFICATION AGAINST APPLICABLE BSC OBJECTIVES

This section outlines the initial views of the Modification Group regarding the merits of P211 against the Applicable BSC Objectives.

4.1 Proposed Modification

The initial **MAJORITY** view of the Modification Group was that the Proposed Modification **WOULD NOT** better facilitate the achievement of Applicable BSC Objectives (b), (c) or (d) when compared to the current Code baseline, for the following reasons:

Applicable BSC Objective (b)

- Cost reflectivity will be reduced as the Proposed solution moves away from what the SO actually did to resolve the imbalance on the system. Cost reflective Energy imbalance prices are essential to provide the correct incentives for parties to balance. These costs should then be appropriately targeted on those who are out of balance. As P211 will reduce the level in which the SO's costs are reflected in Energy Imbalance Prices it follows that these costs will not be appropriately targeted and the incentives for Parties to balance will decrease. This in turn increases the actions required to be taken by the SO and increases the costs faced by the SO. This would be detrimental to efficiency;
- The Modification creates a trade-off where more cost reflective Energy Imbalance Prices are sacrificed in all Settlement Periods for removing a defect that has only been shown to occur from time to time. It is accepted that transmission constraints have an impact on the Energy Imbalance Price but there is currently a tagging mechanism to deal with these (even if it can be shown to occasionally be defective). The issue of transmission constraints should arguably resolved in a different manner such that it is not at the expense of cost reflective prices;
- The increase in SO activities is in conflict with NETA principles in which it is assumed that it is more efficient for Parties to balance than the SO. With less incentives to balance then this is moving away from Parties balancing and puts this cost onto the SO; and

- Parties will not respond appropriately in periods of system stress if the signals are distorted due to prices not being reflective of actual SO costs of balancing the system. If, on average, Parties expect a more benign Energy Imbalance Price due to the EPUS stack including volumes that the SO cannot feasibly access then they will make a rational decision to only trade in the forward market at a price lower than the forward price under the current arrangements. The reduced incentive to trade results in more imbalance and higher costs for the SO.

One Group member stated that the Modification did better facilitate the objective for the following reasons:

- Prices will be more cost reflective because the proposal will remove the impact of system balancing actions which, it was argued, has a significant impact on the main imbalance price. The analysis also shows that prices do rise at times of system stress therefore retaining appropriate signals to balance; and
- There is a reduced incentive for Parties to go long on average. Therefore the actions the SO needs to take to balance the system will decrease resulting in lower costs and greater efficiency to balance the system.

Applicable BSC Objective (c)

- All Parties contribute proportionately to the costs of balancing via the Balancing Services Use of System (BSuOs) charge and those that are out of balance via SBP and SSP. The Proposal moves away from reflecting the costs incurred by the SO to resolve the net imbalance on the system. This results in a greater proportion of balancing costs being socialised across all Parties rather than being targeted at those in imbalance. This cross subsidy will be detrimental to competition.
- There will be changes to Parties behaviour based on the P211 arrangements. Parties would be able to take advantage of the rules that exclude dynamic parameters to influence the Energy Imbalance Price. Similarly, Parties may inadvertently impact (or, due to competition or market abuse issues be very wary of inadvertently impacting) the Energy Imbalance Price whenever they update their data. This would create distortions in the Energy Imbalance Prices that would not reflect the true costs of balancing. As the forward price is driven by the Energy Imbalance prices this will create the wrong signals to the market and therefore hinder competition. Where any attempt to take advantage of the P211 rules occurs, this will be very difficult to track;
- Appropriate signals to the market are distorted if the costs of high priced plant being used to balance the system are not reflected in the Energy Imbalance Prices. This would occur when the EPUS stack contains many offers which the SO cannot actually use; and
- The prices will be benign most of the time with a decreased level of volatility. Thus there is less incentive to balance or trade.

One Group member stated that the Modification did better facilitate the objective for the following reasons:

- It is simpler to understand encouraging new entrants as well as encouraging existing Parties to trade;
- Liquidity will increase as Parties are more likely to sell available volume in the forward market than hold it to self-hedge;
- Parties will pay a better cost of energy imbalance and not a price that contains actions taken for system balancing reasons.

Applicable BSC Objective (d)

- It has not been proven that there is a case for change in that the perceived defect has been shown to occur but is not shown to be a substantive issue. Therefore there is no justification for the costs of this change;
- P211 introduces a new and approximate arrangement for cash out, there is no evidence that it would be administered more efficiently; and
- The current arrangements are based on a simple concept; to reflect the costs of the SO when balancing the system. P211 would move away from this simple concept.

One Group member stated that the Modification did better facilitate the objective for the following reasons:

- Current actions taken by the SO for system balancing are impacting Energy Imbalance Prices and P211 provides a better reflection of the actions that could have been taken so the price is more cost reflective; and
- The Proposed solution is simpler for Parties to understand and for the industry to implement and operate.

One Group member additionally argued that potential issues arising from security of supply would not better facilitate the achievement of Applicable BSC Objectives (a).

4.2 Potential Alternative Modification

The Modification Group were unconvinced that the potential Alternative Modification would better facilitate the achievement of Applicable BSC Objectives (b), (c) or (d) when compared to the Proposed Modification.

A number of members felt the potential Alternative went some way to addressing their concerns that the solution should seek to only include those Bids and Offers that can be 'accessed' by the SO and was therefore more accurate than the Proposed. However, this increases the complexity of the solution. Those members further commented that the potential Alternative had already had to be modified by the Group to account for anomalous results on certain stress days and there was a concern that there were other anomalies associated with the rules that would require further Modification if this potential Alternative was approved.

Further comments were made in relation to the lack of transparency of the Potential Alternative in that data would be available to view, but it would be more difficult to validate how the Energy Imbalance Price was calculated. This reduces the predictability of Energy Imbalance Prices.

The Group member who believed that the Proposed Modification did better facilitate the objectives did not believe the potential Alternative better facilitates the objectives due to the complexity and noted that the prices obtained as a result of the rules being applied were (save for the stress days identified) not very different.

On group member was undecided as to whether the potential Alternative proposal better facilitated the objectives. They recognised that this option presented a trade off between a generally less cost reflective price but one that would not be impacted by any actions taken to resolve constraints. This group member felt that the further price analysis that is scheduled to be published later on in this consultation would enable them to take a better view on this question.

The Group therefore concluded that the Potential Alternative would not facilitate the objectives better than the current baseline.

5 TERMS USED IN THIS DOCUMENT

Other acronyms and defined terms take the meanings defined in Section X of the Code.

Acronym/Term	Definition
BMRA	Balancing Mechanism Reporting Agent
BSAD	Balancing Services Adjustment Data
DABV	Deemed Available Bid Volumes - Determined by the difference between the time weighted FPNs and time weighted MILs
DAOV	Deemed Available Offer Volumes – Determined by the difference between the time weighted FPNs and time weighted MELs
EPUS	Ex-Post Unconstrained Schedule – The stack of all Bids and Offers that are available to the SO. The EPUS is made up of the differences between FPN and MEL and FPN and MEL for all relevant BMUs.
FPN	The Final Physical Notification is the level of generation or demand that the BMU Trader expects to generate or consume. Submitted as a ramped profile to NGC prior to Gate Closure.
Main Energy Imbalance Price	The Energy Imbalance Price applied to imbalances in the same direction as the system.
MIL	Minimum Import Limit
MEL	Maximum Export Limit
MNZT	The minimum time in minutes that a BM Unit can operate at a non-zero level as a result of a Bid-Offer Acceptance
NISM	
NIV	Net Imbalance Volume
PAR	Price Average Reference
PAR Tagging	The process of removing Acceptance Volumes from the calculation of Energy Imbalance Prices
PAR Volume	Price Average Reference Volume, the volume of actions that are used to set the Main Energy Imbalance Price
RCRC	Residual Cashflow Reallocation Cashflow
Reverse Price	The price applied to imbalances in the opposite direction to the system. This is based on the market reference price derived from data submitted by Market Index Data Providers.
RDR	Run Down Rate
RUR	Run Up Rate
SBP	System Buy Price
SEL	Stable Export Limit
SIL	Stable Import Limit
SO	System Operator
SSP	System Sell Price

6 DOCUMENT CONTROL

6.1 Authorities

Version	Date	Author	Reviewer	Reason for Review
0.1	01/08/07	Chris Stewart	David Jones/Justin Andrews	For technical/peer review
0.2	06/08/07	Chris Stewart	David Jones	For Quality Review
0.3	06/08/07	Chris Stewart	P211 Modification Group	For Modification Group review
0.4	14/08/07	Chris Stewart	P211 Modification Group	For Modification Group review
1.0	15/08/07	P211 Modification Group		For industry consultation

6.2 References

Ref.	Document Title	Owner	Issue Date	Version
1	Ofgems Cash Out Review – Independent Consultants' Reports http://www.ofgem.gov.uk/MARKETS/WHLMKTS/COMPANDEFF/CASHOUTREV/Pages/CashoutRev.aspx	Ofgem	22/03/2007	
2	P205 'Increase in PAR volume from 100MWh to 500MWh' - Decision Letter http://www.ofgem.gov.uk/Pages/MoreInformation.aspx?docid=86&refer=Markets/WhlMkts/CompandEff/CashoutRev	Ofgem	22/03/2007	

APPENDIX 1: APPLICABLE BSC OBJECTIVES

For reference the Applicable BSC Objectives, as contained in the Transmission Licence, are:

(a) The efficient discharge by the licensee [i.e. the Transmission Company] of the obligations imposed upon it by this licence [i.e. the Transmission Licence];

(b) The efficient, economic and co-ordinated operation of the GB transmission system;

(c) Promoting effective competition in the generation and supply of electricity, and (so far as consistent therewith) promoting such competition in the sale and purchase of electricity;

(d) Promoting efficiency in the implementation and administration of the balancing and settlement arrangements.

APPENDIX 2: PROCESS FOLLOWED

Copies of all documents referred to in the table below can be found on the BSC Website at: http://www.elexon.co.uk/ChangeImplementation/modificationprocess/modificationdocumentation/modProposalView.aspx?propID=231

Date	Event
16/04/07	Modification Proposal raised by EDF Energy
10/05/07	IWA presented to the Panel
15/05/07	First Assessment Procedure Modification Group meeting held
22/05/07	Second Assessment Procedure Modification Group Meeting held
06/06/07	Third Assessment Procedure Modification Group Meeting held
13/06/07	Fourth Assessment Procedure Modification Group Meeting held
18/06/07	Request for Transmission Company analysis on Proposed Solution issued
18/06/07	Proposed Requirements Specification issued for BSC Agent impact assessment
19/0607	Proposed Modelling exercise undertaken
2/07/07	Party Agent Proposed impact assessment responses returned
2/07/07	Transmission Company analysis for Proposed returned
4/07/07	Fifth Assessment Procedure Modification Group Meeting held
18/07/07	Modelling Exercise Results
23/07/07	Sixth Assessment Procedure Modification Group Meeting held
24/07/07	Potential Alternative Modelling exercise undertaken
27/07/07	Potential Alternative Requirements Specification issued for BSC Agent impact assessment
27/07/07	Request for Transmission Company analysis on Potential Alternative Solution issued
8/08/07	BSC Agent Proposed impact assessment responses returned
8/08/07	Transmission Company analysis for Proposed returned

Date	Event
13/08/07	Seventh Assessment Procedure Modification Group meeting held
15/08/07	Issue Consultation Document
17/08/07	Potential Alternative Modelling results

ESTIMATED COSTS OF PROGRESSING MODIFICATION PROPOSAL[29]

Meeting Cost	£ 2,250
Legal/Expert Cost	£ 5,000
Impact Assessment Cost	£ 10,000
ELEXON Resource	130 man days £41,390

Note that the number of ELEXON man days (and cost) will need to be updated to represent the additional analysis requested by the Group.

[29] Clarification of the meanings of the cost terms in this appendix can be found on the BSC Website at the following link: http://www.elexon.co.uk/documents/Change_and_Implementation/Modifications_Process_-_Related_Documents/Clarification_of_Costs_in_Modification_Procedure_Reports.pdf.

MODIFICATION GROUP MEMBERSHIP

Member	Organisation	15/05	22/05	06/06	13/06	04/07	23/07	08/08	29/08
David Jones	BSCCo (Chairman meetings 3 to 8)			√	√	√	√	√	
Justin Andrews	BSCCo (Chairman meetings 1 and 2)	√	√		√	√	√		
Chris Stewart	BSCCo (Lead Analyst)	√	√	√	√	√		√	
David Lewis	EDF (P211 Proposer)	√	√	√	√	√		√	
Rob Smith	National Grid	√	√	√	√	√	√	√	
Lisa Waters	WatersWye	√	√	√					
Bill Reed	RWE Trading	√	√	√	√			√	
Libby Glazebrook	First Hydro Company		√	√	√	√	√	√	
Man Kwong Liu	Saic (on behalf of Scottish Power)	√	√	√	√		√	√	
Ian Moss	APX Group	√	√	√		√			
Paul Jones	E.ON UK	√	√	√		√	√	√	
Paul Dawson	Barclays Capital		√						
David Wilkerson	Centrica	√	√	√		√			
Andrew Colley	Scottish and Southern	√	√	√	√	√	√	√	
Martin Mate	British Energy	√	√	√	√			√	
Keith Munday	Bizz Energy				√				
Bob Brown	Cornwall Energy Associates	√	√	√	√				
Alison Hughes	Bizz Energy	√	√						

Attendee	Organisation	15/05	22/05	06/06	13/06	04/07	18/07	08/08	29/08
Natasha Hall	BSCCo (Lawyer)	√	√		√	√			
Shantok Karavadra	BSCCo (Lawyer)	√	√	√	√				
Kevin Swinton	BSCCo	√	√	√	√				
John Guest	Logica	√	√	√		√	√		
Mark Gribble	Logica		√	√	√	√			
Ben Woodside	Ofgem	√	√	√			√		

Duncan Mills	Ofgem			√	√	√		√	
Richard Jones	npower	√		√	√	√	√	√	
Duncan Sinclair	Ofgem				√				
Kate Boon	First Hydro Company	√							
Alexandra Campbell	E.ON UK	√							
Colin Prestwich	Smartest Energy	√	√	√	√	√			
Colin Berry	BSCCo	√ (part)							
Sebastian Eyre	EDF Energy	√					√	√	
John Sykes	BSC Panel	√	√				√		
Barbara Vest	BSC Panel	√ (part)							
Paul Mott	EDF Energy		√			√	√	√	
Ben Sheehy	E.ON UK				√				
Nigel Cornwall	Panel					√			
Rekha Patel	WatersWye						√		
Jonathan Blott	LogicaCMG						√	√ (part)	
Alex Kay	EDF Energy						√		
Jessie He	Npower						√		
Grahame Swinton	BSCCo						√	√	

Modification Group Terms of Reference Terms of Reference

(Version 1.0)

Annex for Modification Proposal P211

Modification Proposal P211 will be considered by a new Modification Group, the P211 Modification Group, comprised of members of the Pricing Standing Modification Group (PSMG), and members of other Modification Standing Groups with the relevant expertise in the areas of Cash-out, Energy Imbalance Pricing, energy and system balancing, tagging and default price rules.

P211 – Main Imbalance Price based on Ex-Post Unconstrained Schedule

1. ASSESSMENT PROCEDURE

1.1 The Modification Group will consider Modification Proposal P211 pursuant to section F2.6 of the Balancing and Settlement Code.

1.2 The Modification Group will produce an Assessment Report for consideration at the BSC Panel Meeting on 13 September 2007.

1.3 The Modification Group shall consider and/or include in the Assessment Report as appropriate:

Ex Post Unconstrained Schedule (EPUS) Derivation

- The degree to which the EPUS may include Bids and Offers that could not be delivered by the BMU or that the SO could not take for any physical reason.
- The impact of including/excluding dynamic parameters on the derivation of the EPUS. The Modification Group should determine which (if any) dynamic parameters should be included or excluded. This may require data to be provided by National Grid Electricity Transmission (NGET) on these parameters and potentially modelling of the derivation of the EPUS by NGET. In addition, consideration should be given to the appropriateness of despatch algorithms for constructing the EPUS;
- The impact of using the difference between Final Physical Notice (FPN) and Maximum Export Limit / Maximum Import Limit (MEL/MIL) as a measure of available Bids and Offers to the System Operator.
- Are there are any other methods for deriving the EPUS that can be identified and the relevant costs and benefits of any such derivations. An ex-post unconstrained schedule is currently used in other wholesale electricity market jurisdictions in the formulation of wholesale electricity prices thus where the information is readily available the Modification Group shall consider:
    - The reasons for introducing the EPUS into these jurisdictions including any benefit/dis-benefit (including costs) information; and
    - The similarities and differences between the BSC arrangements and those of the other jurisdictions;
- How an Unconstrained Schedule was used under the pre NETA arrangements (Pool);
- How Balancing Services Adjustment Data (BSAD) is treated and how it will enter the EPUS; and

- How de-minimus Bids and Offers should be treated within the EPUS.

Impact on Prices

- The degree to which system balancing actions enter Energy Imbalance Prices under the existing Energy Imbalance Price calculation;
- The degree to which including/excluding dynamic parameters in the EPUS affects prices;
- Using historic data, the calculation of the Energy Imbalance Prices that would have been generated had the P211 mechanism been applied for certain historic Settlement Days including those in which it has been identified that system balancing actions have entered the Energy Imbalance Price; and
- The Energy Imbalance Prices generated for historic Settlement Days by both the current mechanism and that proposed by P211 in the context of the prevailing market conditions. This will also support the assessment of whether the proposed mechanism provides more cost reflective prices than the current baseline.

Cashflow Analysis

The impact on Residual Cashflow Reallocation Cashflow (RCRC) including any distributional impacts identified.

Incentives

- Having regard for the fact that price volatility is made up of volatility that correctly represents conditions in the market and volatility which bears little relationship to market/system conditions, the Modification Group should consider the degree to which price volatility is impacted and the resulting incentives to take an unbalanced position into cash-out;
- A qualitative assessment of how using the current operational parameters of FPN, MEL and MIL (and any other relevant Grid Code parameters) in the formation of the EPUS might introduce a commercial driver to use these as trading parameters. Additionally, the degree to which this might have a detrimental impact on the ability of the SO to use the submitted values as true indications of capability;
- A qualitative assessment of the potential for Market Participants to manipulate the operational parameters or any dynamic parameters that form part of the solution.
- Identifying any ways in which any potential for manipulation identified can be mitigated; and
- A qualitative view of the degree to which liquidity might be impacted and the incentive to enter forward contracts.

Impact on Settlement

The impact of P211 on the Settlement calculation and the publication of prompt prices. This will be informed by the BSC Agent impact assessments and information provided by the Transmission Company. The Modification Group should identify if there is any difference in prompt prices between P211 and the current arrangements and establish a view on the materiality of any disparity in the timeliness of calculating this data.

Default Rules

The default rules should be reviewed including:

- When there is insufficient deemed volume of Bids/Offers to resolve the NIV will be required; and
- Interaction of volumes covered by Bid / Offer pairs and the volumes up to the MEL / MEL that are not priced.

Implementation

Any Potential Alternative routes for implementation and the impact this has on implementation costs and timescales. Such an Potential Alternative might be NGET producing the prices or an EPUS as opposed to the costs of doing this centrally. The Modification Group should also consider any resulting impact on transparency.

1.4 The derivation of NIV and the PAR level of 500MWh are excluded from these terms of reference.

APPENDIX 3: RESULTS OF IMPACT ASSESSMENT

Unless otherwise noted, the impacts below are for both the Proposed and Potential Alternative Modifications.

a) Impact on BSC Systems and Processes

System / Process	Impact of Proposed/Potential Alternative Modification
Settlement	The amendment of the Energy Imbalance Price calculation impacts the derivation of the Energy Imbalance Prices. The BMRA and SAA systems and processes will be impacted.
Reporting	It is envisaged that the revised Energy Imbalance Prices will be reported within the current interface structure. It will be necessary to amend the Settlement Report (SAA-I014) to reflect the new price derivation (including the new parameters for the Potential Alternative). This will require additional reporting on the elements that make up the EPUS based prices. Specifically for the SAA-I014: • the DAOV, DABV, EBVA and/or ESVA per BM Unit and Bid-Offer number that resolves the NIV; • the DAOV, DABV, EBVA and/or ESVA per BM Unit and Bid-Offer number that have been PAR tagged; and • the DAOV and DABV per BM Unit and Bid-Offer number that have been EPUS Arbitrage tagged.

A copy of the full BSC Agent impact assessment for the Proposed Solution and the potential Alternative are attached as separate documents, Attachments 4 and 5 (respectively).

b) Impact on BSC Agent Contractual Arrangements

BSC Agent Contract	Impact of Proposed/Potential Alternative Modification
LogicaCMG	The SAA and BMRA System will be impacted. SAA reporting is affected. The SAA and BMRA Service Descriptions will also be impacted.

c) Impact on BSC Parties and Party Agents

As this Modification is a change to the Energy Imbalance Calculation, this is a significant change to one of the main tenets of the BSC Arrangements that will impact Settlement for all BSC Parties. Recipients of SAA reports (SAA-I013) will be affected by changes to the information provided. Additionally, Parties will be impacted by the change to sub-flow 1 of the Settlement Report (SAA-I014).

d) Impact on Transmission Company

The Transmission Company impact assessment for P211 Proposed is included as Attachment 6. The Transmission Company impact assessment for P211 Potential Alternative is included as Attachment 7.

e) Impact on BSCCo

Area of Business	Impact of Proposed/Potential Alternative Modification
BSCCo Systems	The Trading Operations Market Assurance System (TOMAS) will be impacted. Any change to the structure of SAA-I014 will impact ELEXON's Gatekeeper software.
Other (e.g. costs, staffing, etc.)	• Industry Guidance notes may require revision to reflect changes to the approach to calculation of Energy Imbalance Prices. • The Change Implementation Team will be required to manage implementation of P211. • Corporate Assurance will be required to support the implementation project. • The Design Authority team will provide Technical Assurance during the implementation project.

f) Impact on Code

Code Section	Impact of Proposed/Potential Alternative Modification
Section Q 'Balancing Mechanism Activities'	Section Q may require amendment if there are changes to the BM data provided by NGET.
Section T 'Settlement and Trading Charges'	Section T would require amendment to detail the changes to the Energy Imbalance Price calculation.
Section V 'Reporting'	Section V would require amendment to detail the Reporting changes.
Annex X	Annex X would require amendment to introduce new, and remove any redundant, definitions.

g) Impact on Code Subsidiary Documents

Document	Impact of Proposed/Potential Alternative Modification
SAA SD	The SAA Service Description will be impacted.
BMRA SD	The BMRA Service Description will be impacted.

h) Impact on Core Industry Documents/System Operator-Transmission Owner Code

Document	Impact of Proposed/Potential Alternative Modification
Grid Code	Note that as operational parameters MIL and MEL will now also be used as a trading parameter to create the EPUS. For the Potential Alternative, SEL, SIL RUR and RDR will also be used

Document	Impact of Proposed/Potential Alternative Modification
	as trading parameters. This degree of this impact is dependent on Parties behaviour.

i) Impact on Other Configurable Items

Document	Impact of Proposed/Potential Alternative Modification
SAA User Requirements Specification (and system documentation)	SAA documentation would require amendment to detail the amendments to the Energy Imbalance Price calculation.
BMRA User Requirements Specification (and system documentation)	BMRA documentation would require amendment to detail the amendments to the Energy Imbalance Price calculation.
BSC Business Process Model	The ELEXON BPM would require amendment to reflect the amendments to the Settlement calculations.
Interface Definition and Design	The IDD parts 1 and 2 will be impacted by the changes.

j) Impact on BSCCo Memorandum and Articles of Association

No impact.

k) Impact on Governance and Regulatory Framework

No impact.