

ASSESSMENT CONSULTATION for Modification Proposal P217 'Revised Tagging Process and Calculation of Cash Out Prices'

Prepared by: P217 Modification Group

For attention of: BSC Parties and other interested parties
Responses due: 5pm on Wednesday 21 May 2008
(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 P217 seeks to improve the main Energy Imbalance Price calculation by introducing a new set of rules to replace the existing tagging rules and by using disaggregated Balancing Services Adjustment Data (BSAD). The intention of the new rules is to remove or replace costs not considered suitable for inclusion in a pure energy price. Proposed Modification P217 would also reduce the Price Average Reference (PAR) value to 100MWh.

Alternative Modification P217 is identical to the Proposed Solution apart from the current PAR volume of 500MWh being retained.

PURPOSE OF CONSULTATION

- This consultation seeks respondents' views regarding P217. For details of the question please turn over.

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

Please send responses, entitled 'P217 Assessment Procedure Consultation', by **5pm on Wednesday 21 May 2008** 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:

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¹ The current version of the Code can be found at <http://www.elexon.co.uk/bscrelateddocs/BSC/default.aspx>.

Consultation questions

In your response please consider the following questions:

1. Do you believe Proposed Modification P217 would better facilitate the achievement of the Applicable BSC Objectives?

Please give rationale and state objective(s)

2. Do you believe Alternative Modification P217 would better facilitate the achievement of the Applicable BSC Objectives when compared to the current baseline?

Please give rationale and state objective(s)

3. Do you believe Alternative Modification P217 would better facilitate the achievement of the Applicable BSC Objectives when compared to the Proposed Modification?

Please give rationale and state objective(s)

4. Do you support the implementation approach described in the consultation document? (See Section 2.5 and 3.15)

Please give rationale

5. What do you believe are the overall costs and benefit of P217? In your opinion, is there a net benefit? (See Section 3.11)

6. P217 will provide additional information in relation to transmission constraints in real time. Do you have any views on the additional transparency of this information? In particular:

a) whether it is likely to impact Parties pricing behaviour; and

b) whether the increased transparency would facilitate the industry's ability to self police, or Ofgem's ability to monitor any market abuse.

7. The Modification Group has recommended that full BMRA reporting would be implemented by the BSC Agent (See section 2.4 and 3.14 and Attachment C). This would impact the BMRA reporting in a similar manner as SAA-IO14 reporting (which was indicated in the P217 Requirement Specification). As such, would P217, with the Full BMRA reporting, impact your organisation? If yes, please provide the estimated cost to your organisation.

8. Do you believe there are any alternative solutions that the Modification Group has not identified and that should be considered within the remaining timetable?

Please give rationale

9. Does P217 raise any issues that you believe have not been identified so far and that should be progressed as part of the Assessment Procedure? Are there any further comments on P217 that you wish to make?

Please give rationale

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SUMMARY OF IMPACTED PARTIES AND DOCUMENTS

As far as the P217 Modification Group (the 'Group') has been able to assess, the following parties/documents would be impacted by P217.

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

Parties	Sections of the BSC	Code Subsidiary Documents
Distribution System Operators <input type="checkbox"/>	A <input type="checkbox"/>	BSC Procedures <input checked="" type="checkbox"/>
Generators <input checked="" type="checkbox"/>	B <input type="checkbox"/>	Codes of Practice <input type="checkbox"/>
Interconnectors <input checked="" type="checkbox"/>	C <input type="checkbox"/>	BSC Service Descriptions <input checked="" type="checkbox"/>
Licence Exemptable Generators <input checked="" type="checkbox"/>	D <input type="checkbox"/>	Party Service Lines <input type="checkbox"/>
Non-Physical Traders <input checked="" type="checkbox"/>	E <input type="checkbox"/>	Data Catalogues <input checked="" type="checkbox"/>
Suppliers <input checked="" type="checkbox"/>	F <input type="checkbox"/>	Communication Requirements Documents <input type="checkbox"/>
Transmission Company <input checked="" type="checkbox"/>	G <input type="checkbox"/>	Reporting Catalogue <input checked="" type="checkbox"/>
Party Agents	H <input type="checkbox"/>	Core Industry Documents
Data Aggregators <input type="checkbox"/>	I <input type="checkbox"/>	Ancillary Services Agreement <input type="checkbox"/>
Data Collectors <input type="checkbox"/>	J <input type="checkbox"/>	British Grid Systems Agreement <input type="checkbox"/>
Meter Administrators <input type="checkbox"/>	K <input type="checkbox"/>	Data Transfer Services Agreement <input type="checkbox"/>
Meter Operator Agents <input type="checkbox"/>	L <input type="checkbox"/>	Distribution Code <input type="checkbox"/>
ECVNA <input type="checkbox"/>	M <input type="checkbox"/>	Distribution Connection and Use of System Agreement <input type="checkbox"/>
MVRNA <input type="checkbox"/>	N <input type="checkbox"/>	Grid Code <input type="checkbox"/>
BSC Agents	O <input type="checkbox"/>	Master Registration Agreement <input type="checkbox"/>
SAA <input checked="" type="checkbox"/>	P <input type="checkbox"/>	Supplemental Agreements <input type="checkbox"/>
FAA <input type="checkbox"/>	Q <input checked="" type="checkbox"/>	Use of Interconnector Agreement <input type="checkbox"/>
BMRA <input checked="" type="checkbox"/>	R <input type="checkbox"/>	BSCCo
ECVAA <input type="checkbox"/>	S <input type="checkbox"/>	Internal Working Procedures <input checked="" type="checkbox"/>
CDCA <input type="checkbox"/>	T <input checked="" type="checkbox"/>	BSC Panel/Panel Committees
TAA <input type="checkbox"/>	U <input type="checkbox"/>	Working Practices <input type="checkbox"/>
CRA <input type="checkbox"/>	V <input checked="" type="checkbox"/>	Other
SVAA <input type="checkbox"/>	W <input type="checkbox"/>	Market Index Data Provider <input type="checkbox"/>
Teleswitch Agent <input type="checkbox"/>	X <input checked="" type="checkbox"/>	Market Index Definition Statement <input type="checkbox"/>
BSC Auditor <input type="checkbox"/>		System Operator-Transmission Owner Code <input checked="" type="checkbox"/>
Profile Administrator <input type="checkbox"/>		Transmission Licence <input checked="" type="checkbox"/>
Certification Agent <input type="checkbox"/>		
Other Agents		
Supplier Meter Registration Agent <input type="checkbox"/>		
Unmetered Supplies Operator <input type="checkbox"/>		
Data Transfer BSC Service Provider <input type="checkbox"/>		

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1 HIGH LEVEL SUMMARY

Background

A BSC Party is required to pay Energy Imbalance Prices when its credited energy (e.g. metered volume or volume reallocation) does not match its notified contract volume (e.g. energy sale or purchase). Imbalance settlement, or 'cash out', is designed so that any electricity generated or consumed which is not covered by contracts is paid for at a price that reflects the short term energy costs incurred by the SO in rectifying the residual System imbalance. Further detail and background on the current arrangements can be found in Appendix 4.

Why was P217 raised?

The Proposer believes that Imbalance Prices are currently being polluted by expensive actions that the System Operator has taken in order to manage locational transmission constraints. The current tagging processes do not always remove these expensive actions from the Imbalance Price. A new set of rules would replace the current tagging processes. These include tagging, flagging and classification processes. The Proposer suggests that this would make the main Energy Imbalance Price more reflective of the short term energy balancing costs that the SO incurs. Further detail can be found in Appendix 4.

Proposed Solution

The P217 Proposed Modification would introduce:

- The disaggregation of BSAD; (see Section 2.1.1)
- The concept of flagging (see Section 2.1.3):
 - SO identification, (referred to as 'flagging'), of balancing actions deemed as potentially being impacted by transmission constraint;
 - Continuous Acceptance Duration Limit (CADL) flagging of short duration actions;
- The concept of classification, where a flagged action would retain its price if it were less expensively priced than the most expensive unflagged action in its stack (Buy or Sell) (see Section 2.1.7);
- A Replacement Price for any unpriced balancing actions that enter into the Net Imbalance Volume (NIV). The Replacement Price would be calculated from a volume-weighted average of the 100MWh of 'most expensively priced actions' (from the perspective of the System Operator) remaining in the NIV, and
- A reduced Price Average Reference volume of 100MWh.

Alternative Modification Solution

The Alternative Modification is identical to the Proposed Solution apart from the retention of the current PAR volume of 500MWh.

Advantages and Disadvantages

P217 Proposed and Alternative when compared to current baseline:

Main advantages:

- Reduces impact of locational transmission constraints on the main Energy Imbalance Price. The main Energy Imbalance Price would be more reflective of the short-term cost of energy imbalance. Imbalance Prices that are more cost reflective have benefits in relation to competition (Applicable BSC Objective (c)) and the efficient, economic and co-ordinated operation of the GB transmission system (Applicable BSC Objective (b)); and

- Greater transparency in the arrangements as more detail of the Imbalance Price calculation is reported, and a new guidance document 'Imbalance Pricing Guidance' would explain the arrangements in simple English. This has benefits in relation to competition (Applicable BSC Objective (c)) and the efficiency in the implementation and administration of the balancing and settlement arrangements (Applicable BSC Objective (d)).

Main disadvantages:

- Potential for Parties to misuse the constraint information and price more keenly;
- Does not perfectly identify all actions taken because of transmission constraints (and in some cases may not flag an action taken for transmission constraints); and
- Significant implementation costs.

The reasons for the majority Group preference for the Alternative Modification over the Proposed Modification is that retaining the PAR volume at 500MWh reduces some of the uncertainty that surrounds the introduction of the new arrangements. It mitigates against the potential for some transmission constraints to not be identified by the new methodology, and the degree of transmission constraints entering the main Energy Imbalance Price would be better understood after a period of implementation;

Initial Recommendation

The **MAJORITY** of the Group believe P217 Proposed Modification **WOULD** better facilitate Applicable BSC Objective (b), (c) and (d) when compared to the current baseline. However, only a **MINORITY** of Group members believed the P217 Proposed Modification **WOULD** better facilitate the achievement of Applicable BSC Objectives (b), (c) or (d) when compared to the Alternative Modification.

The **MAJORITY** of the Group believe P217 Alternative Modification **WOULD** better facilitate Applicable BSC Objective (b), (c) and (d) when compared to the current baseline and P217 Proposed.

Costs

BSC Agent – £282,200

BSCCo – £124,400

Transmission Company – £658,000 + £167,000 of contingency

Parties – maximum of £50,000 (most around £10,000)

Implementation Impacts

BSC Agent – High

BSCCo – High

Transmission Company – High

Parties – Medium to low

For a description of the impacts see Section 2.4 and 3.14.

A description of the P217 solution is provided in Section 2, with the Group's views against the Applicable BSC Objectives in Section 2.3. Further information regarding the Group's initial discussions of the areas set out in the P217 Terms of Reference is contained in Section 3.

2 P217 – THE SOLUTION

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

For a full description of the original Modification Proposal as submitted by RWE npower ('the Proposer'), please refer to the P217 Initial Written Assessment (IWA) ([Reference 2](#)).

2.1 Proposed solution

The P217 Proposed Modification would introduce:

- The dis-aggregation of BSAD (see Section 2.1.1);
- Flagging (see Section 2.1.3):
 - SO identification, (referred to as 'flagging'), of balancing actions deemed as potentially being impacted by transmission constraint;
 - Continuous Acceptance Duration Limit (CADL) flagging of actions (i.e. CADL actions would not immediately be tagged as unpriced and will undergo 'classification');
- A new process for processing Emergency Instructions (see Section 2.1.4);
- No change to De-Minimis or Arbitrage tagging (see Section 2.1.5 and 2.1.6 respectively);
- A classification process for flagged actions whereby an action would retain its price if it were less expensively priced than the most expensive unflagged action in its stack (Buy or Sell). A flagged action which is more expensively priced than the most expensive unflagged action would be classified as unpriced (and may be subject to the Replacement Price) (see Section 2.1.7);
- A Replacement Price for any unpriced balancing actions that enter into the Net Imbalance Volume (NIV). The Replacement Price would be calculated from a volume-weighted average of the 100MWh of most expensively priced actions remaining in the NIV (see Section 2.1.9); and
- A reduced Price Average Reference (PAR) volume of 100MWh.

2.1.1 Disaggregated BSAD

BSAD would be disaggregated. Currently it is submitted as 8 aggregated variables:

1. EBCA_j (Net Buy-Price Cost Adjustment)(Energy)
2. EBVA_j (Net Buy-Price Volume Adjustment)(Energy)
3. SBVA_j (Net Buy-Price Volume Adjustment)(System)
4. ESCA_j (Net Sell-Price Cost Adjustment)(Energy)
5. ESVA_j (Net Sell-Price Volume Adjustment)(Energy)
6. SSVA_j (Net Sell-Price Volume Adjustment)(System)
7. BPA_j (Buy-Price Price Adjustment)
8. SPA_j (Sell-Price Price Adjustment)

Note that variables 1 – 6 would remain (to minimise change to BSC Central Systems and the Transmission Company systems) but would be submitted as zero. The treatment of the BPA and SPA would be unchanged.

Each individual disaggregated BSAD would undergo the same tagging and classification processes as BOAs (see Sections 2.1.2 to 2.1.11). Disaggregated BSAD would be submitted by the SO to BSC Central Systems with a price, volume and flag.

The exception to this would be a disaggregated BSAD item where the price is 'NULL'. This is intended to enable the SO to submit disaggregated BSAD volumes for certain exceptional actions (e.g., certain types of intertrip²) where no cost can be allocated at the time of data submission. As there is no price the disaggregated BSAD with a NULL price would be treated as Flagged (unpriced) and would not undergo the classification process.

The addition of the Buy Price Adjuster (BPA) or Sell Price Adjuster (SPA) would continue as under the current arrangements.

2.1.2 Order of the Main Energy Imbalance Price calculation

The main Energy Imbalance Price calculation processes would be ordered as follows:

1. Flagging (System Operator flagging and CADL flagging)
2. Emergency Instruction Processing
3. De Minimis tagging
4. Arbitrage tagging
5. Classification
6. NIV tagging
7. Replacement Price process (if required)
8. PAR tagging

These processes describe how Bid-Offer Acceptances (BOAs) and disaggregated BSAD are treated in the Price calculation. A Bid-Offer Acceptance issued by the System Operator consists of a series of two or more MW levels at particular times at which a BM Unit is expected to operate. The volume in each half-hour between the implied MW profile (with linear interpolation between the points) and the profile which the BM Unit was previously expected to follow based on its Physical Notification and any previous BOAs is calculated and sub-divided into submitted price bands. These volumes are referred to in the BSC as the Period Accepted Offer Volume (QAO^{kn}_{ij}) and/or Period Accepted Bid Volume (QAB^{kn}_{ij}). Each BOA is identified by:

- It's BM Unit (BM Unit Identification Number (i));
- The relevant Settlement Period (j),
- The Bid-Offer Pair Number (n) – (given that there can be up to 5 Bid-Offer Pairs for each BMU); and
- The Bid-Offer Acceptance Number (k).

2.1.3 Flagging

Flagging is a process that identifies BOAs and disaggregated BSAD items that are considered as potentially having a non-energy component. If a Bid Offer Acceptance is flagged, the Period Accepted Offer Volume

² An intertrip automatically disconnects a generator or demand from the System when a specific event occurs. There are two types of intertrip service: Commercial Intertrip and System to Generator Operational Intertrip. These intertrip services are used as an automatic control arrangement to reduce or disconnect generation or demand following a system fault event to relieve localised network overloads, maintain system stability, manage system voltages and/or ensure quick restoration of the Transmission System. Intertrip-derived BSAD may not have a price assigned because payment by the SO may not be in a suitable form for prompt inclusion as a price. Intertrip derived disaggregated BSAD would always be flagged by the System Operator, even though the energy delivered may be in merit for meeting an energy imbalance.

(QAO^{kn}_{ij}) and the Period Accepted Bid Volume (QAB^{kn}_{ij}) volumes derived from that Acceptance are also referred to as being flagged.

2.1.3.1 System Operator ex-ante constraint flagging

The SO would flag BOAs ex-ante which it believes would be impacted by locational transmission constraints. The details of the flagging process would be documented either in the BSAD Methodology Statement, or drafted into a new Constraint Flagging Methodology Statement (both outside the scope of the BSC). This methodology statement would be drafted by the SO during the implementation of P217. For the purposes of the BSC, the SO would submit details of whether the BOA was flagged or unflagged to the BSC Central Systems.

2.1.3.2 Continuous Acceptance Duration Limit (CADL) flagging

CADL shall be used for flagging (and not tagging as it is currently) BOAs of short duration. If a BOA is part of a series of Acceptances of continuous duration less than CADL, it would be flagged by the BSC Central Systems. CADL would remain set to 15 minutes.

The revised CADL flagging algorithm would also resolve a known anomaly in the current CADL process. If more than one Acceptance is taken on a given BM Unit, the current process removes all Acceptances provided that at least one of them is part of a short duration series. Under P217, only Acceptances that are actually part of a short duration series shall be flagged. Other Acceptances (longer than the CADL but part of which were in the same Settlement Period as a CADL flagged action) on the same BM Unit would not be flagged.

2.1.4 Emergency Instruction Processing

Emergency Instructions would be flagged or not flagged by the System Operator as to whether they were taken purely for energy reasons. The resulting actions would be treated like any other action. Manual data submission by the System Operator will continue in accordance with the current baseline but will also include the flagging information.

2.1.5 De Minimis tagging

Period Accepted Offer Volumes (QAO^{kn}_{ij}), Period Accepted Bid Volumes (QAB^{kn}_{ij}) and disaggregated BSAD volumes would be subject to De Minimis Tagging. Both flagged and unflagged actions may be tagged. The De Minimis Acceptance Threshold (DMAT) would remain as 1MWh. The following rules would apply:

- i. If the volume of a BSAD item is less than DMAT, it would be tagged and excluded from the Energy Imbalance Price calculation.
- ii. For actions relating to Bid Offer Acceptances, De Minimis tagging would continue to be based on the Period BM Unit Total Accepted Offer Volume (QAO^n_{ij}) and the Period BM Unit Total Accepted Bid Volume (QAB^n_{ij}). These are given by:

$$QAO^n_{ij} = \sum_k QAO^{kn}_{ij}$$

$$QAB^n_{ij} = \sum_k QAB^{kn}_{ij} .$$

If QAO^n_{ij} or QAB^n_{ij} is less than DMAT, then each constituent action³ shall be excluded from the Energy Imbalance Price calculation. A description of existing De Minimis Tagging can be found in Appendix 4.

³ I.e., each of the Period Accepted Offer Volumes (QAO^{kn}_{ij}) or Period Accepted Bid Volumes (QAB^{kn}_{ij}) within the scope of summation.

2.1.6 Arbitrage Tagging

Period Accepted Offer Volumes (QAO_{ij}^{kn}), Period Accepted Bid Volumes (QAB_{ij}^{kn}) and disaggregated BSAD items would be subject to Arbitrage Tagging. Arbitrage volumes would be excluded from the main Energy Imbalance Price calculation. A description of existing Arbitrage Tagging can be found in Appendix 4.

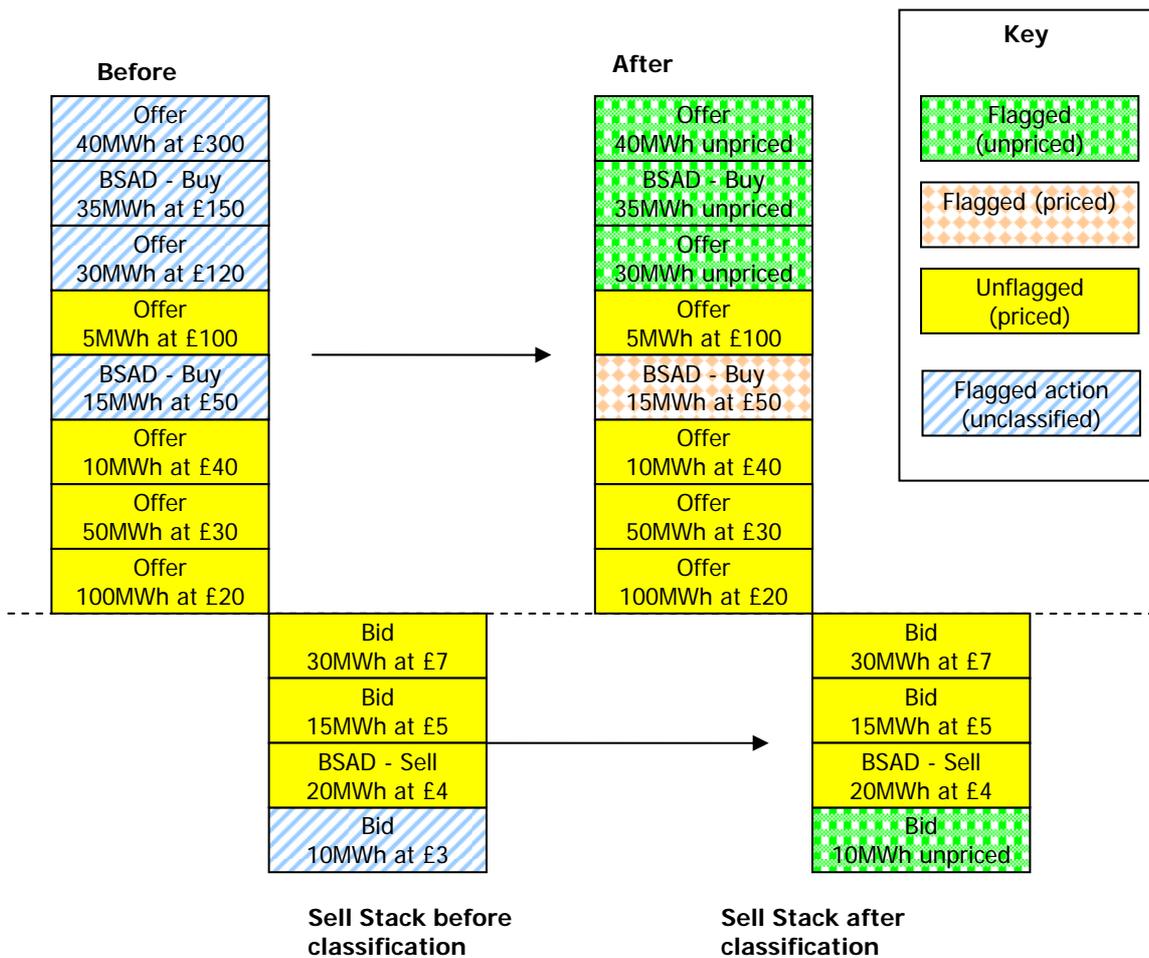
2.1.7 Classification

The next stage is to determine the set of actions that will have their costs reflected in the main Energy Imbalance calculation. This is referred to as "Classification". Classification would occur for the Buy Stack and the Sell Stack independently. The following rules would apply:

1. Unflagged actions shall always remain priced and be classified as 'Unflagged (priced)'.
2. If there are no unflagged actions in a given stack, all actions in that stack shall be classified as 'Flagged (unpriced)'. Otherwise, each flagged action shall be compared with the most expensive unflagged action in the same stack.
 - a) If a flagged Offer or BSAD Buy action has a price higher than the highest-priced unflagged Offer or BSAD Buy action in the Buy Stack, then it shall become temporarily unpriced and classified as '**Flagged (unpriced)**'.
 - b) If a flagged Bid or BSAD Sell action has a price lower than the lowest-priced unflagged Bid or BSAD Sell action in the Sell Stack, then it shall become temporarily unpriced and classified as '**Flagged (unpriced)**'.
 - c) If a flagged Offer or BSAD Buy action has a price equal to or lower than the highest priced unflagged Offer or BSAD Buy action in its stack, then it shall remain priced (at the price submitted by the Party) and classified as '**Flagged (priced)**'.
 - d) If a flagged Bid or BSAD Sell action has a price equal to or higher than the lowest priced unflagged Bid or BSAD Sell action in its stack, then it shall remain priced (at the price submitted by the Party) and classified as '**Flagged (priced)**'.

It should be noted that NULL-priced BSAD items will always be classified as 'Flagged (unpriced)'.

Figure 2: Example of 'classification'



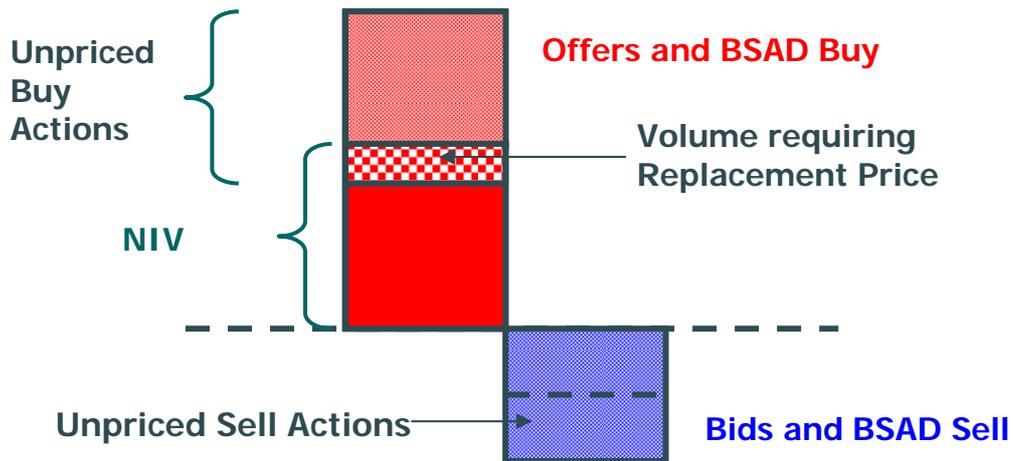
2.1.8 Net Imbalance Volume (NIV) tagging

Period Accepted Offer Volumes (QAO^{kn}_{ij}), Period Accepted Bid Volumes (QAB^{kn}_{ij}) and disaggregated BSAD items would be subject to NIV Tagging. No other changes are proposed to the current Net Imbalance Volume (NIV) Tagging process (See Appendix 4). NIV tagging shall occur after all actions have been classified.

2.1.9 Replacement Price process

There will potentially be situations where some of the volume in the NIV may not have a price associated with it. An example is shown below:

Figure 3: An example where a Replacement Price is required

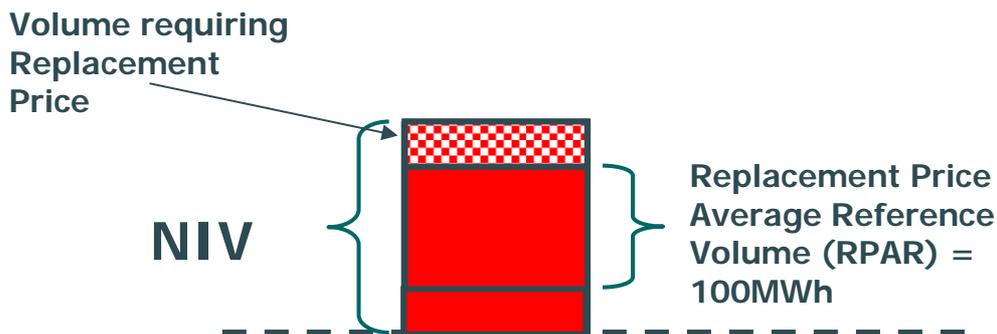


Where such unpriced volume exists in the NIV, it shall be assigned a Replacement Price. A new parameter, called the Replacement Price Average Reference (RPAR) volume, would be used in to determine the Replacement Price. The RPAR would be 100MWh. The RPAR would be a changeable parameter with changes only occurring as a result of a Modification to the BSC.

The Replacement Price would be calculated from a volume-weighted average of the most expensively priced actions remaining in the NIV. This concept is the same as that of the current PAR. The average would be taken over the volume of most expensively priced actions (both Unflagged (priced) and Flagged (priced)) in the NIV which is greater than zero but is less than or equal to 100MWh. If the NIV consists only of unpriced actions, the Replacement Price (and therefore the main Energy Imbalance Price) would default to the Reverse Price (Market Price).

An example is shown below:

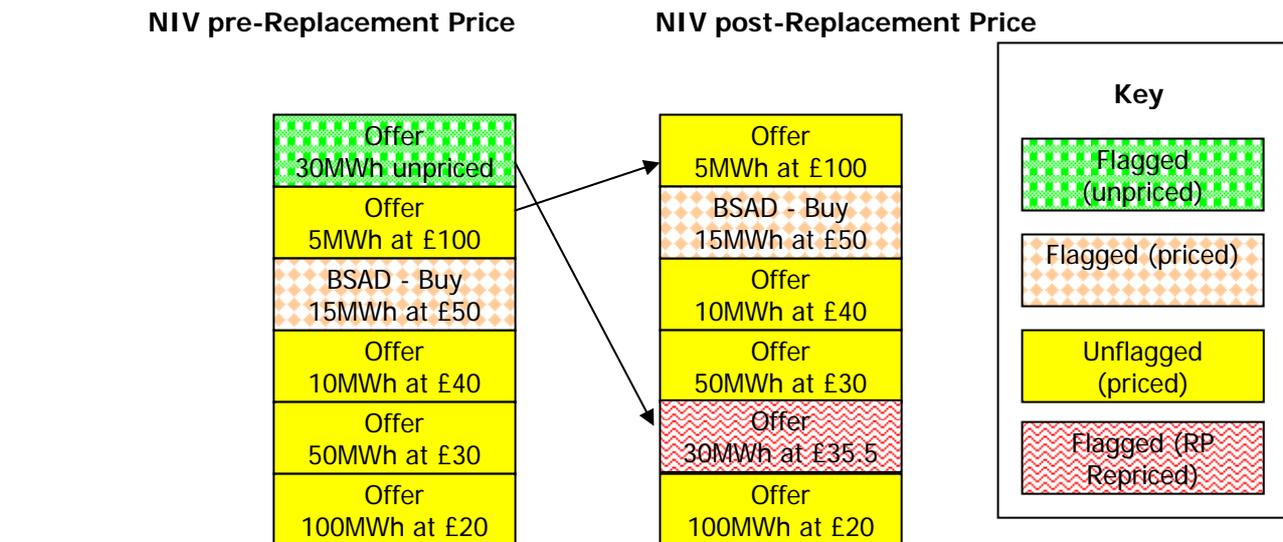
Figure 4: Example of the Replacement Price Average Reference Volume



A Replacement Price would be calculated separately for each Settlement Period (if required - i.e. there is unpriced volume in the NIV). The Replacement Price would be assigned to all unpriced actions remaining in the NIV.

Once the Replacement Price has been assigned, the stack would be rearranged (where necessary) to rank the actions again in price order. This is required to ensure that the stacks are in price order for PAR tagging (see Section 2.1.10). An example of this rearrangement is shown below.

Figure 5: Demonstration of rearranging a NIV stack after the Replacement Price has been applied to unpriced volume



2.1.10 Price Average Reference (PAR) tagging

Period Accepted Offer Volumes (QAO^{kn}_{ij}), Period Accepted Bid Volumes (QAB^{kn}_{ij}) and disaggregated BSAD items would undergo PAR Tagging as at present. The average of the most expensive volumes remaining in the NIV stack (after other volumes are 'NIV tagged') up to a total volume of PAR are used to set the main Energy Imbalance Price, the volumes not within PAR being 'PAR tagged'. Proposed Modification P217 would amend the PAR volume to 100MWh. Other than that the PAR tagging process would be unchanged.

2.1.11 The Final Stages of the Calculation of the main Energy Imbalance Price

No other changes are proposed to final stages of the main Energy Imbalance Price calculation. For the avoidance of doubt, the treatment of BSAD variables and Transmission Losses shall continue as under the current baseline. However, it is worth emphasising that the following six BSAD variables (which currently are used to submit aggregated BSAD and identified as items 1 to 6 in Section 2.1.1) would be submitted as zero by the SO.

2.1.12 Defaulting rules

The following defaulting rules for the main Energy Imbalance Price would apply in exceptional circumstances. There would be no change to the default rules if the liquidity threshold for the reverse Energy Imbalance Price is not met.

2.1.12.1 Replacement Price

If the volume of priced actions in the NIV is less than RPAR but greater than zero, a volume weighted average of these priced actions (whatever their volume may be) would be used to determine the Replacement Price. If the NIV consists only of unpriced actions, the Replacement Price would be the Reverse Price (Market Price)⁴.

2.1.12.2 NIV and PAR

No changes are proposed. If the volume of NIV is less than PAR but greater than zero, a volume weighted average of these priced actions (whatever their volume) would be used to determine the main Energy Imbalance price. If the NIV is zero, the main Energy Imbalance Price would be the Reverse Price (Market Price).

2.1.12.3 System Buy Price (SBP) cannot be lower than System Sell Price (SSP)

No changes are proposed. If the calculation of System Buy Price (SBP) (as either the main or the reverse Energy Imbalance Price) would result in a lower price than the calculation of System Sell Price (SSP), then both SBP and SSP would be set equal to the result of the main Energy Imbalance Price calculation.

2.1.13 Changes to the SAA I-014 flow

A new version of the SAA I-014 "Settlement Reports" flow would be created for each variant of the flow. There are substantial changes, and are detailed in Appendix 5. This includes:

1. There would be a new record type for disaggregated BSAD (including an indicator showing whether or not the BSAD item was flagged by the System Operator);
2. The 'BM Unit Period Bid Offer Acceptance' record would indicate whether or not the BOA was flagged (either by the System Operator or by the BSC Central Systems);
3. The 'BM Unit Period Bid Offer Data' record would include the eight types of BOA volume for each Bid Offer pair;
4. The 'Settlement Period Information (System Period Data)' record (SPI) shall be updated;
5. Reporting the Replacement Price; and
6. Reporting the RPAR value.

2.1.14 Changes to the Balancing Mechanism Reporting Service (BMRS)

The BMRS website would include the same additional information as in the new version of the SAA I-014. As far as is possible BOA volumes and disaggregated BSAD items would be treated uniformly.

Changes would also be required to the High Grade BMRS service reported via TibCo. New message types would be created to report the new information whenever possible. The new TibCo messages shall include the same additional information as in the new version of the SAA I-014.

2.2 Alternative Solution

The Alternative Modification is identical to the Proposed Solution apart from the PAR volume being set at the current value of **500MWh**.

⁴ As noted before, this specific rule may not be needed if the defaulting rules are implemented in a different way that ensures the same Energy Imbalance Price.

2.3 Group views against the Applicable BSC Objectives

2.3.1 Conclusion

The initial **MAJORITY** view of the Group is that the Alternative Modification **WOULD** better facilitate the achievement of Applicable BSC Objectives (b), (c) or (d) when compared to the current Code baseline and the Proposed Modification.

The initial **MAJORITY** view of the Group is that the Proposed Modification **WOULD** better facilitate the achievement of Applicable BSC Objectives (b), (c) or (d) when compared to the current Code baseline. However, only a **MINORITY** of Group members believed the Proposed Modification **WOULD** better facilitate the achievement of Applicable BSC Objectives (b), (c) or (d) when compared to the Alternative Modification.

2.3.2 Proposed Modification

The initial **MAJORITY** view of the Modification Group was that the Proposed Modification **WOULD** better facilitate the achievement of Applicable BSC Objectives (b), (c) or (d) when compared to the current Code baseline, for the reasons given in the second column of the table below.

The initial **MINORITY** 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 reasons given in the third column of the table below.

Applicable BSC Objective	Better facilitates the Applicable BSC Objective against the current baseline	Does not better facilitate the Applicable BSC Objective against the current baseline
(a)	<ul style="list-style-type: none"> Neutral 	<ul style="list-style-type: none"> Neutral
(b)	<ul style="list-style-type: none"> P217 Proposed would provide a more cost reflective main Energy Imbalance Price as the impact of transmission constraints would be significantly reduced. This would increase the degree to which only the energy costs of the SO in balancing the system are accurately reflected in Energy Imbalance Prices. Cost reflective Energy Imbalance Prices and the appropriate targeting of those are essential to provide the correct incentives for Parties to balance. With Parties facing the correct incentives to balance, P217 Proposed would reduce the SO costs for balancing the System when compared to the current arrangements. (Note that, although BSUoS costs are outside of the BSC, 	<ul style="list-style-type: none"> P217 Proposed is likely to lead to greater transparency of the location, frequency and duration of active transmission constraints, although, identification of constraint boundaries would not be explicitly revealed. This extra information and transparency may lead to Parties pricing more keenly in an area with an active transmission constraint. This could increase the SO balancing costs. The increased visibility of transmission constraints could give BSC parties with larger generation portfolios the ability to move contracted generation load in or out of the transmission constraint zone and exacerbate the boundary value. Such activity could require the SO to procure or sell greater levels of generation, potentially at an unattractive premium, to secure the system.

Applicable BSC Objective	Better facilitates the Applicable BSC Objective against the current baseline	Does not better facilitate the Applicable BSC Objective against the current baseline
	<p>the Transmission Company's analysis estimates an anticipated £4 million reduction in BSUoS costs per annum with the implementation of P217 Proposed). This would be beneficial to the efficient operation of the GB transmission system.</p> <ul style="list-style-type: none"> By moving towards a more marginal pricing methodology, the P217 Proposed would provide more appropriate signals for market participants to balance. 	<ul style="list-style-type: none"> The more marginal pricing regime of P217 Proposed may mean that some generators would withhold capacity to self hedge rather than offering this in the balancing mechanism. This would increase the SO costs for balancing the system.
(c)	<ul style="list-style-type: none"> P217 Proposed should result in a more cost reflective main Energy Imbalance Price by accurately reflecting only the energy costs incurred by the SO to resolve the net imbalance on the system. This would result in the costs of balancing being more accurately targeted on those Parties out of balance. Therefore it is believed that P217 would provide greater market competition given that Parties would be faced with the correct incentives. P217 Proposed would introduce a greater transparency into the imbalance pricing arrangements. Participants would be able to attain a greater understanding of how the main Energy Imbalance Price would be calculated and which areas were constrained. Transparency facilitates competition by encouraging new entrants and providing for more favourable arrangements for existing Parties to operate under. As all Parties would be able to see constrained areas this may act as a counter to any detrimental changes in behaviour. It is possible that any pricing or locational load swapping activity would be visible to the general market community. The Imbalance Pricing Guidance document would reduce one of the barriers to entry – the difficulty for new 	<ul style="list-style-type: none"> Introducing a more marginal PAR volume could reduce competition as smaller Parties, who have historically proved less able to balance, would be subject to a generally higher SBP when they are short and the system is short. Introducing a more marginal price may amplify any imperfections of the P217 methodology (as set out in Section 3.2).

Applicable BSC Objective	Better facilitates the Applicable BSC Objective against the current baseline	Does not better facilitate the Applicable BSC Objective against the current baseline
	entrants to understand the imbalance pricing arrangements.	
(d)	<ul style="list-style-type: none"> The Imbalance Pricing Guidance documents should increase the efficiency of the operation of the BSC as there would be greater industry understanding in how imbalance prices are calculated thereby reducing Imbalance Pricing related questions to ELEXON. 	<ul style="list-style-type: none"> P217 Proposed is a more complex solution than the current baseline. P217 Proposed has a significant BSCCo and BSC Agent implementation cost.

2.3.3 Alternative Modification

The initial **MAJORITY** view of the Group is that the Alternative Modification **WOULD** better facilitate the achievement of Applicable BSC Objectives (b), (c) or (d) when compared to the current Code baseline, for the reasons given in the second column of the table below.

The initial **MINORITY** view of the Group is that the Alternative Modification **WOULD NOT** better facilitate the achievement of Applicable BSC Objectives (b), (c) or (d) when compared to the current Code baseline, for the reasons given in the third column of the table below.

Applicable BSC Objective	Better facilitates the Applicable BSC Objective against the current baseline	Does not better facilitate the Applicable BSC Objective against the current baseline
(a)	<ul style="list-style-type: none"> Neutral. 	<ul style="list-style-type: none"> Neutral.
(b)	<ul style="list-style-type: none"> Same arguments as for the Proposed Modification. 	<ul style="list-style-type: none"> P217 Alternative could increase the Transmission Company's costs for balancing the System when compared to the current arrangements. Whilst not a BSC cost the Transmission Company's analysis reports an estimated £150,000 increase in BSUoS costs per year with the implementation of P217 Alternative. P217 Alternative is likely to lead to greater understanding of information relating to the location, frequency and duration of active transmission constraints, although, identification of constraint boundaries would not be explicitly revealed. This extra information may lead to Parties pricing more keenly in an area with an active transmission constraint. This could increase the SO balancing costs.

Applicable BSC Objective	Better facilitates the Applicable BSC Objective against the current baseline	Does not better facilitate the Applicable BSC Objective against the current baseline
		<ul style="list-style-type: none"> The increased visibility of transmission constraints could give Parties with larger generation portfolios the ability to move contracted generation load in or out of the transmission constraint zone and exacerbate the boundary value. Such activity could require the SO to procure or sell greater levels of generation, potentially at an unattractive premium, to secure the system.
(c)	<ul style="list-style-type: none"> Same arguments as for the Proposed Modification. 	<ul style="list-style-type: none"> Introducing a more marginal price may amplify any imperfections of the P217 methodology (as set out in Section 3.2).
(d)	<ul style="list-style-type: none"> Same arguments as for the Proposed Modification. 	<ul style="list-style-type: none"> Same arguments as for the Proposed Modification.

2.3.4 Proposed vs Alternative

The initial **MAJORITY** view of the Group is that the Alternative Modification would better facilitate the achievement of Applicable BSC Objectives (b), (c) or (d) when compared to the Proposed Modification. A **MINORITY** of Group members believed the Proposed Modification **WOULD** better facilitate the achievement of Applicable BSC Objectives (b), (c) or (d) when compared to the Alternative Modification. The following reasons were given.

Applicable BSC Objective	Proposed is better than Alternative	Alternative is better than Proposed
(a)	<ul style="list-style-type: none"> Neutral. 	<ul style="list-style-type: none"> Neutral.
(b)	<ul style="list-style-type: none"> P217 Proposed would provide a more cost reflective price. These costs are then appropriately targeted on those Parties who are out of balance providing appropriate incentives to balance. This reduces the SO's costs for balancing the System when compared to P217 Alternative. Note that whilst these are not BSC costs the Transmission Company estimated the following impact on BSUoS charges: <ul style="list-style-type: none"> Proposed - £4 million reduction; and 	<ul style="list-style-type: none"> Keeping the current PAR level of 500MWh mitigates some of the uncertainty that surrounds the introduction of new and complex arrangements. Until the solution has been implemented, and several months of data gathered, the full impact of how accurate P217 is at accurately reflecting only the energy costs of balancing is difficult to assess. Therefore it is pragmatic to retain a PAR of 500MWh until the P217 arrangements (were it to be approved) had been proven to remove non-energy actions. A number of imperfections with the methodology have been identified and recognised as an artefact of the solution (see section 3.2). The majority of the Group believes these imperfections will not

Applicable BSC Objective	Proposed is better than Alternative	Alternative is better than Proposed
	<ul style="list-style-type: none"> ○ Alternative - £150,000 increase. • A PAR level of 500MWh was introduced under Approved Modification P205 in order to reduce the impact of transmission constraints on the main Energy Imbalance Price (The baseline at the time being a PAR level of 100MWh). P217 has been shown to reduce the impact of transmission constraints. Therefore, keeping a PAR of 500MWh (as set out in Alternative) would result in less cost reflective prices than a PAR level of 100MWh. 	<p>cause anomalies that would not occur often. However, without large amounts of actual simulation analysis, it is impossible to be sure (the Group only had 5 days of data in which an actual simulation took place). Introducing a more marginal PAR volume may amplify any anomalies from the imperfections in the methodology that have been identified during the Assessment of P217 (as set out in section 3.2). For example, one unrepresentative action setting the main Energy Imbalance Price.</p> <ul style="list-style-type: none"> • The more marginal pricing regime of P217 Proposed may mean that some generators would hold capacity to self hedge rather than offering this in the balancing mechanism. This would increase the SO costs for balancing the system.
(c)	<ul style="list-style-type: none"> • P217 Proposed would be more cost reflective when compared to P217 Alternative. This more marginal main Energy Imbalance Price would result in the costs of balancing being more accurately targeted on those Parties out of balance. Therefore P217 Proposed would provide greater market competition given that Parties will be faced with the correct incentives. 	<ul style="list-style-type: none"> • Introducing a more marginal PAR volume could reduce competition as smaller Parties who have historically proved less able to balance would be subject to generally higher SBP when they are short, and the system is short. Therefore the less marginal PAR volume of P217 Alternative would be preferable.
(d)	<ul style="list-style-type: none"> • Neutral. 	<ul style="list-style-type: none"> • Neutral.

A number of Group members reiterated their view that they theoretically agreed with a more marginal pricing methodology. The Group's majority preference for the PAR volume of 500MWh over a PAR volume of 100MWh did not prevent the PAR volume being reduced at some point in the future. Perhaps, at a point where a greater understanding of how the P217 arrangements operated, and how accurately it removes non-energy actions was known.

2.4 Implementation Costs and impacts

The implementation costs of P217 would be:

BSC Agent

	Implementation Cost	Tolerance
BSC Agent	£282,200	0%

The BSC Agent would require 35 weeks to implement the change. For full discussion on the BSC Agent's implementation options and approach see Section 3.14. A detailed solution to the impact assessment is provided as Attachment C.

BSCCo

	Implementation Cost	Tolerance
BSCCo	£124,400	10%

The BSCCo costs are split into 270 man days or £59,400 to implement the change (update Code Subsidiary Documentation, testing and deployment), and approximately £65,000 (+/- 30% tolerance) to update the Trading Operations Market Assurance System (TOMAS) to the P217 arrangements. There would be no cost difference between implementing the Proposed and the Alternative.

BSCCo would require 8 weeks to implement P217 following the BSC Agent implementation.

Transmission Company

	Implementation Cost	Contingency
Transmission Company	£658,000	£167,000

For Transmission Company costs are detailed in Attachment F. There would be no cost difference between implementing the Proposed and the Alternative Modification. The Transmission Company implementation timescale is 12 months. For further details see Attachment F. It should be noted that the Transmission Company implementation costs are not recovered through BSC charges, (as is the case with BSC Agent and BSCCo implementation costs), but through Balancing Services Use of System (BSUoS) charges.

Parties and Party Agents

5 Parties responded to the impact assessment. All noted medium to low impacts as a result of P217. Impact assessments had been received from 4 larger Parties and one smaller Party. The highest cost impact was £50,000, and the longest implementation period was 6 - 12 months. However, most Parties reported lower costs and shorter implementation timescales. Parties reported they would be required to change their systems to accept the new SAA IO-14 flow and the new BMRS data.

2.5 Implementation date

The Group has recommended an Implementation Date of:

- 05 November 2009 if an Authority decision is received on or before 30 October 2008; or
- March 2010 (final date to be confirmed) if an Authority decision is received after 30 October 2008 but on or before 25 February 2009.

For further discussion on implementation approach see section 3.15.

3 AREAS DISCUSSED BY THE GROUP AS SET OUT IN THE TERMS OF REFERENCE

This section outlines the initial conclusions of the Modification Group regarding the areas set out in the P217 Terms of Reference. The Panel requested the Group consider the following areas during the Assessment Procedure:

- The detailed rules for the BSC Tagging Methodology Statement;
- The detailed rules for the ex-ante constraint flagging methodology for identifying locational transmission constraints as developed by National Grid;
- The detailed rules for the BSC Replacement Price Methodology Statement, including the size of the 'chunk' used to determine the Replacement Price;
- Reassess the PAR volume for the main Energy Imbalance Price. As part of this reassessment the Group should first consider whether the current value of PAR500 is appropriate for the P217 solution;
- The required governance arrangements for the Tagging Methodology Statement and Replacement Price Methodology Statement, and any interaction with BSAD Methodology Statements;
- Whether there would be any issues completing the proposed tagging process within the existing prompt price reporting timescales;
- The detailed treatment of BSAD under the proposed arrangements. This might include consideration of disaggregated BSAD, the inclusion of BSAD and Option fees (via the BPA and SPA) in the calculation of the main Energy Imbalance Price;
- The Group should outline its justification for the inclusion of reserve in the main Energy Imbalance Price calculation;
- The required reporting under the P217 proposed arrangements; and
- Detailed analysis of the impact on Energy Imbalance Prices.

3.1 Key themes from the price recalculation analysis of the solution

The price recalculation analysis for P217 has been conducted on the whole solution described in Section 2, whereas the Terms of Reference splits up the key elements of the solution. Each of these areas is addressed below where we have highlighted the key themes that emerged. These will be discussed in more detail in the subsequent sections (3.2 to 3.10). In these sections the most significant and useful analysis results are highlighted. See Attachment A for the full analysis results.

Flagging and classification

The key results of the analysis showed that:

- Overall, 17% of volume was flagged;
- Of those flagged actions around:
 - 54% are Flagged (unpriced) after classification; and
 - 46% are Flagged (priced) after classification (that is, they retain their original price);
- During periods in which the NIV is positive (and the system is considered 'short'), a 56% of constraint flagged actions are classified as Flagged (priced). This compares 49% classified as Flagged (priced) when the NIV is negative (and the system is considered 'long'); and

- When compared to constraint flagged actions (53% classified as Flagged (unpriced), a higher percentage of CADL flagged actions are classified as Flagged (unpriced) (58% classified as Flagged (unpriced)).

Replacement Price

The key results of the analysis showed that:

- The Replacement Price is higher for SBP and lower for SSP the smaller the MWh level of RPAR;
- The spread of Replacement Prices is greater the smaller the MWh level of RPAR;
- The volume subject to the replacement price is generally small but in some periods can be greater than the Proposed and Alternative PAR volumes (100MWh and 500MWh respectively); and
- As can be seen from price recalculation results (detailed in Section 3.4), the Replacement Price Volume has a relatively small impact on the main Energy Imbalance Price when compared to the PAR volume.

Main Energy Imbalance Price

The key results of the analysis showed that:

- The chosen level of PAR has a more significant impact on the main Energy Imbalance Price than the level of the Replacement Price volume;
- The greater the PAR volume the lower the SBP and the higher the SSP;
- Decreasing the PAR volume increases the average SBP and reduces the average SSP;
- Setting the PAR volume at the current level of 500MWh reduces the average SBP by 1.2% and increases average SSP by 1.7%% and
- Setting the PAR volume at 100MWh increases the average SBP by 8.6% and decreases average SSP by 3.1%

National Grid Ex-ante constraint flagging

The key results of the analysis showed that:

- Ex-ante flagging by the SO tended to overestimate the number of transmission constraints (or 'over flag') when compared to an ex-post re-consideration by the SO;
- Over the five day analysis period, 13 actions were flagged ex-post that were not flagged ex-ante. It is possible that some transmission constraints would not be flagged if the solution is implemented. However, the SO ability to flag is likely to improve with experience and when moving from the paper based trial done for the analysis to an automated system;
- There were only six Settlement Periods, out of 170, (3.5%) where the main Energy Imbalance Price calculated using the ex-ante flagging were different to those calculated using the ex-post flagging. This indicates that the 'over flagged' actions often retain their price during the classification process.; and
- Where the main Energy Imbalance Prices recalculated for the P217 Proposed and Alternative Modifications differed from the historic (or 'live') main Energy Imbalance Price, the actions flagged were often priced more extremely when compared to the unflagged actions. This suggests that the solution was correctly identifying transmission constraint impacted actions.

Dis-aggregated BSAD

The key results of the analysis showed that:

- There is the potential that the disaggregation of BSAD might result in Parties being able to ascertain information that would put National Grid in a disadvantaged position as a 'distressed' buyer given the price and volumes would be published. In 35% of Settlement Periods where there is a BSAD component, that BSAD component is made up of a single trade. The majority of the Group did not feel this was a substantial issue;
- Disaggregation of BSAD caused an increase in the maximum SSP due to System BSAD (currently unpriced) being classified under P217 as Flagged (priced) and retaining its price;
- Where SSP was the main Energy Imbalance Price, disaggregated BSAD led to higher SSP than aggregated BSAD in all cases where there is a difference (although there was no difference for the vast majority of cases); and
- Where SBP was the main Energy Imbalance Price, there was a more even spread of differences. For the most extreme case aggregated BSAD produced a price which was £36/MWh more expensive than disaggregated BSAD.

Cashflow

The key results of the analysis showed that:

- The Proposed Modification resulted in an increase in RCRC of £23 million;
- The Alternative Modification resulted in a decrease in RCRC of £6 million;
- Because Imbalance Prices are generally stronger (SBP is higher and SSP is lower) under the Proposed Modification than the baseline, those who tend to balance more accurately would be better off (as what they get back in RCRC exceeds the increase in imbalance cost). The analysis for the Proposed Modification indicates that this is the case for larger Parties (funding share >3.5%).
- Because Imbalance Prices are generally weaker (SBP is lower and SSP is higher) under the Alternative Modification than the baseline, it is sensible to expect that those who tend to find it more difficult to balance would be better off (as the decrease in imbalance cost exceeds the decrease in RCRC). The analysis for the Alternative Modification indicates that this is the case for smaller Parties (funding share <0.5%).

It should be noted that the analysis was based on the incentive properties of the current baseline cash out pricing methodology. P217 Proposed is based on more marginal pricing and should result in different outcomes when compared with the current baseline.

3.2 The detailed rules for P217 solution

3.2.1 Conclusion

The P217 Proposed Modification would introduce the following main Energy Imbalance Price rules:

- SO identification, or 'flagging', of transmission constraint impacted balancing actions, and Continuous Duration Acceptance Limit (CADL) flagging of short duration actions;
- A classification process where a flagged action will retain its price if it less expensively priced than the most expensive unflagged action in its stack (Buy or Sell).

3.2.2 Definition Procedure Principles

The P217 Definition Procedure provided the following Principles for the Assessment of P217:

- Using CADL (with current 15 minute duration) would be a pragmatic way to identify and tag intra-half hour short duration actions. CADL should be retained in a P217 solution but modified such that the methodology should only exclude BOAs where these would not normally have been taken to resolve energy imbalances;
- De Minimis and Arbitrage tagging should be retained as currently occurs;
- BM Units from which balancing actions are likely to be required to resolve transmission constraints should be identified by an ex-ante methodology. Actions subsequently taken from these BM Units would be flagged for the purposes of ex-post reporting and Imbalance Price setting. This methodology should only exclude BOAs where these would not normally have been taken to resolve energy imbalances;
- In situations where system flagged actions have a lower price than an 'energy' action, those actions should be classified as 'energy plus system' rather than 'system' and should remain as priced acceptances.
- The 'system', 'energy plus system' and 'energy' tags of accepted Bids, Offers and dis-aggregated BSAD should be published ex-post. Note that the concepts of 'system', 'energy plus system' and 'energy' have been replaced by the classification process;
- Where reserve has been utilised and is not removed through CADL, then this should be included in the main Energy Imbalance Price calculation (i.e. considered as either 'energy' or 'energy plus system').
- Option fees paid by the SO for reserve should be included in the main Energy Imbalance Price calculation;
- MaxGen should be considered an 'energy action' to be included in the main Energy Imbalance Price calculation, subject to normal tagging rules.

3.2.3 Refinements during the Assessment Procedure

The Group agreed the following refinements to the tagging, flagging and classification principles that were defined during the Definition Procedure.

De Minimis and Arbitrage

It was agreed by the Group that all actions should be treated equally (apart from one special case with disaggregated BSAD – discussed in section 3.8). This means that all actions, including disaggregated BSAD, would undergo De Minimis and Arbitrage tagging. Currently, aggregated BSAD does not undergo these two tagging processes as it used by the BSC Systems (and enters the main Energy Imbalance Price calculation)

after De Minimis and Arbitrage tagging takes place. As BSAD would be disaggregated, and BOAs and disaggregated BSAD would be very similar (both being made up of volumes and prices), the Group saw no reason to treat these differently. The Group did note that they would be surprised if De Minimis tagging regularly removed any disaggregated BSAD.

Change to terminology – tagging, flagging and classification

During the Assessment Procedure it became clear that there was potential for confusion with the terminology used. One member pointed out that current terminology suggested a tagged action is one where either: the price has been removed and the volume remains (that is, it is an unpriced volume); or the volume and price have been removed entirely.

Flagging is the identification of an action that was to some extent considered as being taken for system balancing purposes. The Group decided to distinguish the process whereby flagged actions are classified as priced or unpriced from the processes of tagging and flagging. This process was named 'classification'. For the avoidance of doubt the list of tagging, flagging and classification rules is as follows:

Tagging

- De Minimis
- Arbitrage
- NIV
- PAR

Flagging

- CADL
- Constraint
- Emergency Instructions

Classification

- The process which decides whether a flagged action should keep its original price, or be considered unpriced.

Change to the classification terminology

The Modification Proposal sets out that all actions would be classified either 'system', 'energy plus system', or 'energy'. During the Group discussions it became clear that those terms meant different things to different people. The Group was concerned that retaining those terms would lead to debate about their usage, rather than a factual description of when actions are priced and unpriced for the purposes of the main Energy Imbalance Price calculation.

The Group decided that the terms should be renamed in order to be a factual description that included whether the action was flagged or unflagged, and priced or unpriced. It should be noted that these terms only apply to the classification stage, as after NIV tagging, it is possible for Flagged (unpriced) actions that are in the NIV to be assigned a Replacement Price.

The classification terms have been renamed as follows:

Definition Procedure Term	Assessment Procedure Term
Energy	Unflagged (priced)
Energy plus system	Flagged (priced)
System	Flagged (unpriced)

Change to order of main Energy Imbalance Price Calculation

The order that the tagging, flagging and classification processes would occur was set out in the Definition Procedure as follows:

1. SO constraint flagging;
2. De Minimis tagging;
3. Arbitrage tagging;
4. CADL flagging
5. Emergency Instruction Processing;
6. Classification;
7. NIV tagging;
8. Replacement Price process (if required); and
9. PAR tagging.

In discussion with the BSC Agent, it became clear that a slight revision was required in order to keep the treatment of CADL more consistent with the current baseline. This is because the CADL process applies to BOAs, whereas the other processes apply to volumes and prices derived from BOAs. It also became clear that Emergency Instruction processing would also occur before the actions entered into the BSC Systems, and hence needed to be before De Minimis tagging.

Therefore, the final order of the tagging, flagging and classification processes is as follows:

1. SO constraint flagging;
2. CADL flagging
3. Emergency Instruction Processing
4. De Minimis tagging
5. Arbitrage tagging;
6. Classification;
7. NIV tagging;
8. Replacement Price process (if required); and
9. PAR tagging.

It should be noted that the change to the order does not impact the final result of processes 1 to 5 and has been made in order that the treatment of CADL and Emergency instructions are more in keeping with the current baseline, and therefore more efficient to implement.

3.2.4 Analysis of the P217 solution using ex-post constraint flagging data

The Group performed a price recalculation analysis of the new solution and compare it to the current baseline.

With P217 this presented a number of challenges. Firstly, one of the key components of P217 is SO ex-ante constraint flagging. The Group agreed that it was crucial to have some analysis of how accurately the SO flagged constraints and how constraint flagging impacted prices.

With this in mind the Group agreed that the SO would conduct a simulation of ex-ante constraint flagging. However, the Group acknowledged that the simulation would only occur over a number of days - a relatively short period.

A longer period of price recalculation analysis would be required to properly assess P217. Fortunately, the Transmission Company had undertaken an exercise for Ofgem's Regulatory Impact Assessment (RIA) of P211 and P212. Within this exercise, the Transmission Company had identified the BOAs that were impacted by transmission constraints between 1 January 2007 and 30 September 2007.

This identification of transmission constraints had been conducted ex-post, so was not identical to the solution. Similarly, the recalculation of historic prices does not make any allowances for potential behavioural changes. However, it did allow an idea of what a world where transmission constraints were identified, and then treated according to the P217 methodology, may look like.

The Group agreed that ELEXON recalculate the main Energy Imbalance Prices for this period using the Transmission Company data. This would allow a long term comparison of a solution very similar to the P217 solution against the current baseline. The prices calculated under P217 have been compared to the actual historic prices (referred to as 'live' prices). Separately the SO would conduct a shorter duration simulation of the ex-ante solution. The two sets of analysis would allow for members to determine a view of the impact of P217, and whether it better facilitates the Applicable BSC Objectives.

The second challenge was the scope of the solution. As proposed, P217 allowed for the PAR level to be revised to one which the Group believed was appropriate, and also allowed for the Group to develop the RPAR methodology. The Group decided the best way to assess what an appropriate level of PAR would be was to consider different scenarios. These scenarios would differ in the PAR volume and the RPAR volume. The following P217 scenarios were analysed:

1. PAR = 1MWh
2. RPAR = 1MWh, PAR = 100MWh
3. RPAR = 1MWh, PAR = 500MWh
4. RPAR = 100MWh, PAR = 100MWh
5. RPAR = 100MWh, PAR = 500MWh
6. RPAR = 500MWh, PAR = 500MWh

The Group considered it illogical to have a PAR volume of less than the RPAR volume thus these combinations were not included in the analysis.

The analysis of the RPAR and PAR volume and disaggregated BSAD can be found in sections 3.4, 3.5 and 3.6. The details of the ex-ante constraint flagging solution and the analysis of the simulation can be found in section 3.3.

This remainder of this section (3.2.5 and 3.2.6) considers the analysis of the 9 month (1 January 2007 to 30 September 2007) price recalculation.

3.2.5 Analysis of ex-post constraint flagging, CADL flagging and the classification process

The Group considered analysis of flagging and tagging volumes and noted that:

- Overall, 17% of volume was flagged;
- Of those flagged actions:
 - Flagged (unpriced) = 54%
 - Flagged (priced) = 46%;
- During periods in which the NIV is positive (and the system is considered 'short'), 56% of constraint flagged actions are classified as Flagged (priced). This compares 49% classified as Flagged (priced) when the NIV is negative (and the system is considered 'long'); and
- When compared to constraint flagged actions (53% classified as Flagged (unpriced), a higher percentage of CADL flagged actions are classified as Flagged (unpriced) (58% classified as Flagged (unpriced)).

Full results of the analysis can be found in Attachment A.

3.2.6 Features of the solution

P217 solution does reduce the impact of constraints'

29 September 2007 was a day with significant constraints. Much of the accepted Offer volume was flagged under the P217 solution and led to a reduction in SBP when comparing both the Proposed and Alternative SBP to the live SBP. Looking at this day in detail, it can be shown how the P217 flagging, classification and tagging processes can impact the main Energy Imbalance Price. Figure 6 below shows the flagged offer volumes and Figure 7 shows a price comparison for periods where SBP was the main price.

Figure 6 show that there was a large volume identified by the SO as constraint flagged. For Settlement Periods where there is a large flagged unpriced volume but no price differences (such as SP1-14) this is because of the unpriced volume being removed by NIV tagging.

For Settlement Periods where there is a large flagged unpriced volume and significant price differences between the current arrangements and the P217 solution, this is either due to re-priced offers and system BSAD (as in SP17, 21, 38-48) or because of priced system BSAD (as in SP28-31 where the flagged unpriced was mainly removed by NIV tagging).

For Settlement Periods where there is a large flagged priced volume and price differences, these are due to relatively low priced system BSAD. Allowing the system BSAD to be priced means that the higher priced offers are removed by NIV tagging rather than the BSAD (as in SP18-19, 23-25, 33).

Figure 6: Flagged volume on 29 September



Figure 7: System Buy Prices on 29 September for current arrangements, Proposed and Alternative

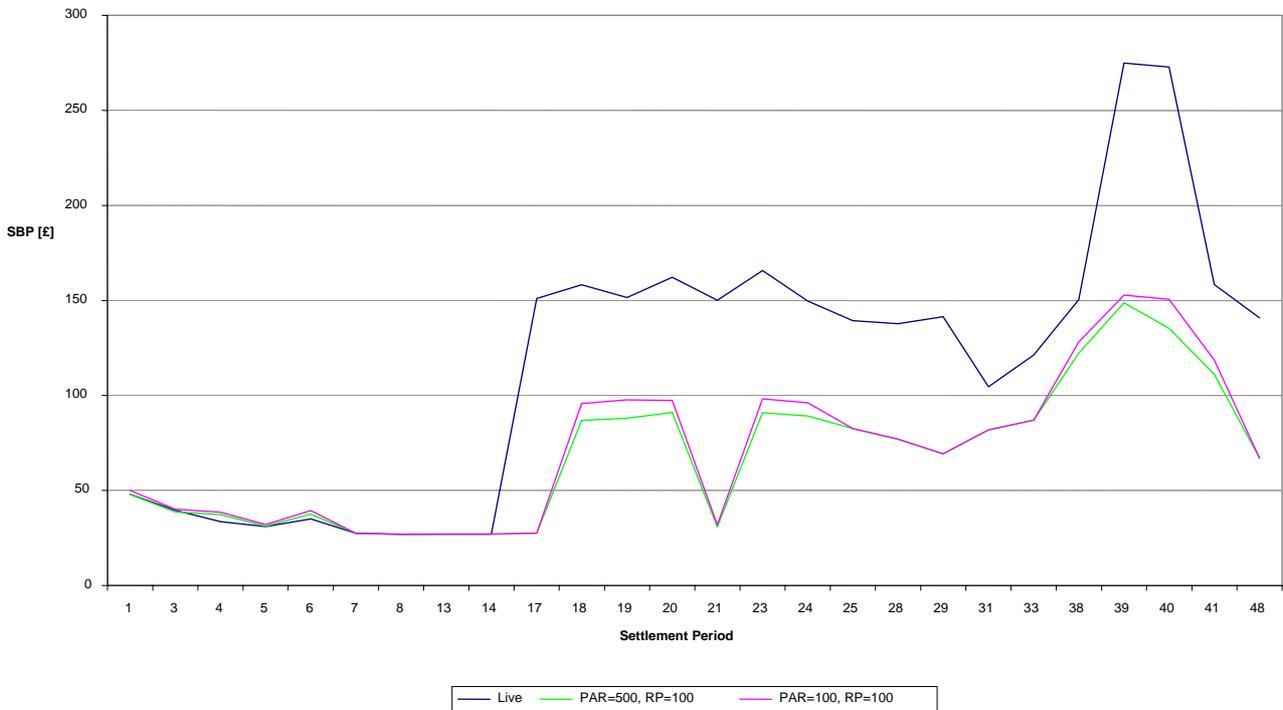
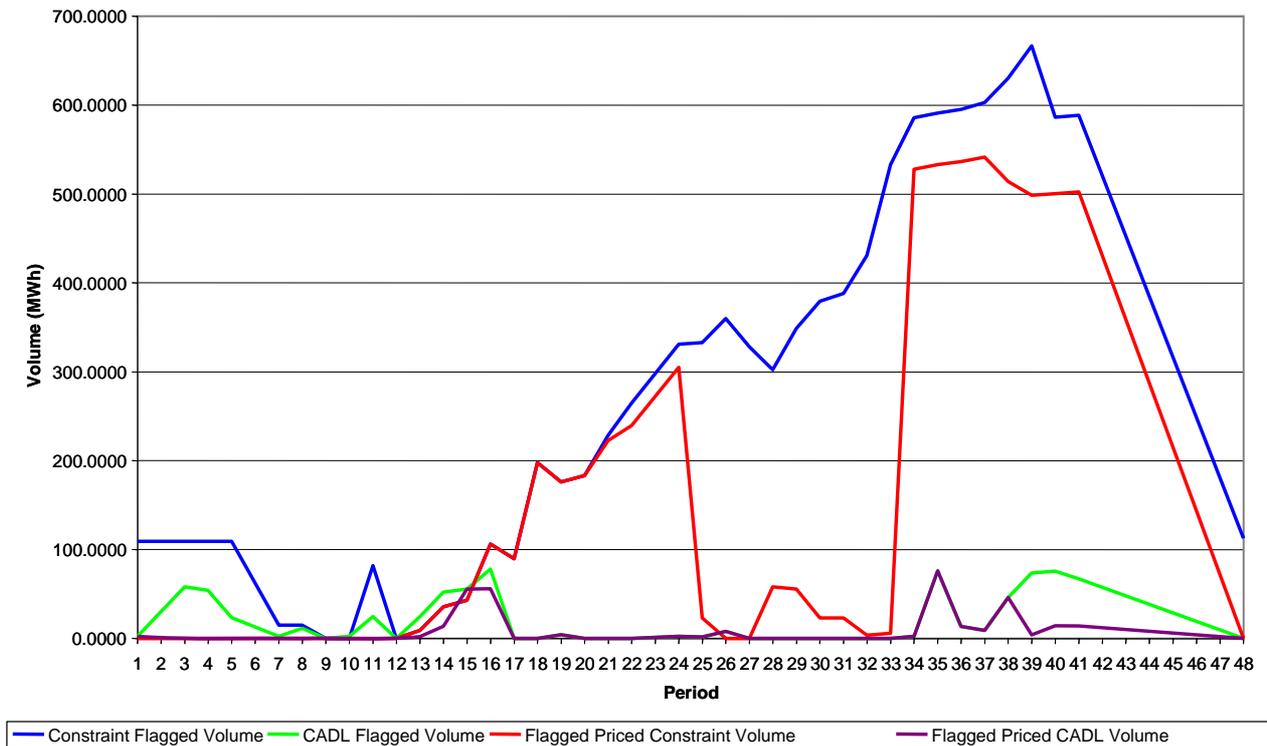


Figure 7 shows that on 29 September 2007, the impact of the transmission constraints on SBP would have been significantly reduced under P217 Proposed and Alternative.

A single unflagged action can price flagged actions below it

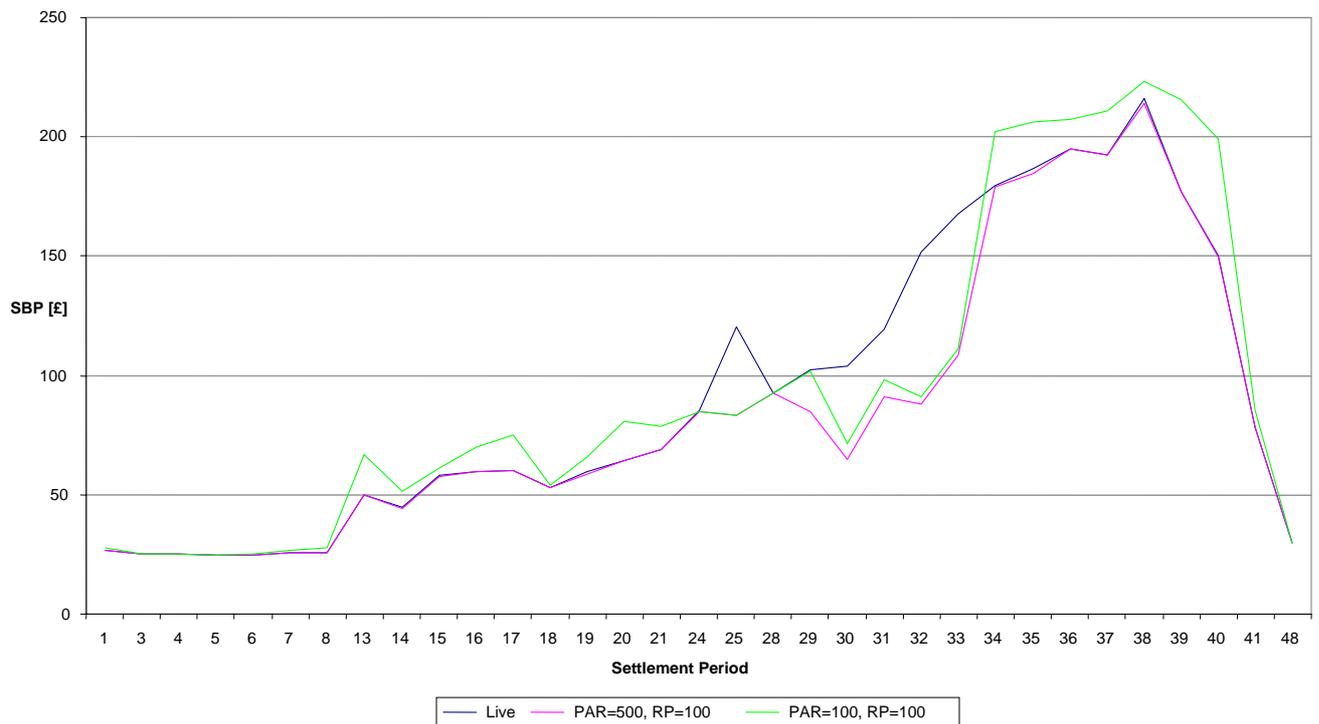
For the constrained day of the 27 September there is a large volume of constraint flagged actions in the second half of the day. This can be seen in Figure 8. For some Settlement Periods 25 to 33 the majority of these flagged actions becomes Flagged (unpriced) whereas for other Settlement Periods 34 to 42 they become Flagged (priced). This is due to a small but high priced Unflagged (priced) action that begins when the system is short (in Settlement Period 34) which sits above a lot of the flagged actions in the stack, and therefore places them in merit.

Figure 8: Flagged volume on 27 September 2007



This single priced action has the following impact on the SBP for this day

Figure 9: System Buy Price on 27 September 2007



The Group noted that there were some instances where constraint flagged actions would retain their price because of a high priced Unflagged (priced) action. A number of Group members argued that if such an action was unflagged, then the actions below it could be considered in merit. Other members believed that such an action should not be able to impact whether constraint flagged action that appeared below it in the stack should retain its price. The Group agreed to document the issue but did not propose any changes to the solution. The majority considered that this was a feature of the methodology, and that if the tagging rules were correct, then by definition the constraint-flagged actions sitting underneath an energy action in the stack were in merit and should be included in the price.

3.3 The ex-ante constraint flagging methodology for identifying locational transmission constraints as developed by National Grid

3.3.1 Conclusion

Under P217, locational transmission constraints would be flagged ex-ante by the SO. The ex-ante constraint flagging solution was developed during the Assessment Procedure by the Transmission Company. The solution evolved from one in which potentially a whole area (covering many BMUs) would be constraint flagged several hours before Gate Closure, to one where BOAs from individual BMUs would be flagged close to real time. The solution would utilise the SO's expertise in identifying transmission constraints during their Planning, Strategy and Real Time stages. The indicator, and subsequently the flag, would only be confirmed as set during the Real Time stage, and could be switched off once the constraint was no longer active.

The SO tested the ex-ante solution (which represents the P217 solution) and compared the resultant main Energy Imbalance Prices to prices calculated with ex-post information (which potentially represents a more accurate solution). The only difference between the two price calculations was that the SO flagged transmission constraints ex-ante in the first, and then updated the set of flagged action with transmission constraints with ex-post hindsight. The SO also provided analysis on the flagging accuracy.

The ex-ante price recalculation was found to over-flag actions in comparison to the ex-post solution. However, this did not materially impact the prices, which were very similar for ex-ante and ex-post results. This low impact was due to the classification process. From the sample days in which the simulation was done, the ex-ante solution captured the significant transmission constraint impacted actions (as shown in 3.2.6 above). However, it was noted that it may not always capture 'marginal' constraint actions, (but these are likely to have a smaller impact on prices). The Group considered that a marginal constraint action was one in which it was not obvious whether the transmission constraint would bite in real time, and where it does, the impact is generally small.

Overall the Group viewed the final solution as an excellent evolution of the original Definition Procedure proposal. The testing suggests the solution would capture the most significant actions (although it was acknowledged that it would not be 100% accurate at identifying actions which are subject to transmission constraints). Over-flagging would be partly mitigated by the classification process.

3.3.2 Where the Group got to during Definition

During the Definition Procedure the Group had agreed that the SO would identify, or 'flag', constraint impacted BOAs in an ex-ante fashion. The details of how the SO would accomplish this were largely left for discussion during the Assessment Procedure.

The SO had originally proposed a methodology called 'big tagging'. The key points of 'big tagging' were:

- Constraint areas would be identified as part of the SO's forward planning;
- All the BMUs in a constraint area would be flagged

On further investigation this had the potential to lead to 'over-flagging' where BMUs would be flagged that were not impacted by the constraint, and therefore should not be flagged.

The SO therefore refined the solution to a two stage process. The first stage would occur during the SO's forward planning process:

- One day ahead, the SO would identify constraint areas and then identify which BMUs would be committed (for BM Start-up or other actions) in those areas in order to alleviate the constraints.
- At that stage, those committed BMUs would be identified by the SO as being impacted by a transmission constraint.

The second stage would occur between the first stage and Gate Closure:

- If the SO identifies a transmission constraint which is about to bite, and they are unable to identify specific BMUs by Gate Closure, the SO would ‘flag’ all BMUs in the area.
- If the SO identifies a transmission constraint which is about to bite, and by Gate Closure they are able to identify specific BMUs, the SO would only ‘flag’ the specific affected BMUs.

The Group agreed that the SO would continue to refine the solution and provide analysis demonstrating how effective it was.

3.3.3 Development of the solution during Assessment

During the Assessment Procedure the SO further refined their ex-ante constraint flagging solution. The solution, as set out in Definition, was found to still over-flag. Therefore, the SO moved away from flagging all BMUs in an area and tested solutions that would allow more BMU specific flagging. To do this, they looked to bring the point at which a BMU/BOA becomes flagged as close to Gate Closure as practical.

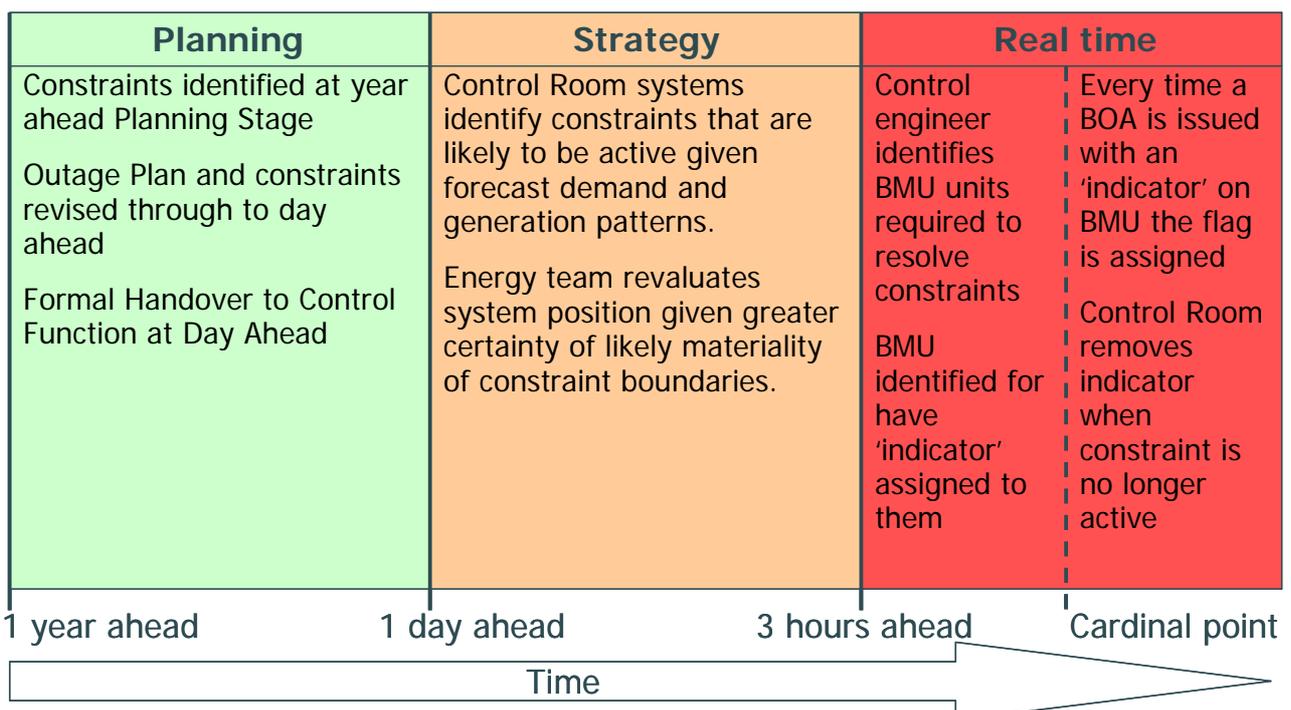
The refined solution involves the control room team setting ‘indicators’ on BMUs which are expected to be impacted by transmission constraints during the Real Time timescale, (which, as seen in Figure 10, occurs from three hours before, up to the point the BOA is despatched). These indicators can be set on or off by control room staff, and so the tendency to over or under flag is reduced. When an ‘indicator’ is set on a BMU, every BOA that is despatched from that BMU would be flagged.

3.3.4 Ex-ante constraint flagging solution

The final ex-ante solution takes advantage of the various stages of constraint planning, from the SO Planning stage, which occurs 1 year ahead to 1 day ahead, through the Strategy stage, (between 1 day ahead to 3 hours ahead), to the Real Time stage. Importantly, it is only at the Real Time stage that an ‘indicator’ would be set. This means that the SO would be setting indicators, and consequentially issuing flagged BOAs, on the most up to date transmission constraint information at any one time.

A timetable of the various stages is shown below.

Figure 10: Timescales for SO ex-ante constraint flagging



The formal handover between the Strategy team and the Real Time team occurs approximately 3 hours prior to real time and is focused on 'cardinal points'. A cardinal point is a pre-determined time during the day when the electricity demand is expected to peak or trough. Once the handover has been completed, the Real Time team have sole responsibility for managing the System and any constraints on it.

A more detailed description of the latter stages of the solution is as follows:

Strategy

- 1 Planning team hand over to Strategy team.
- 2 The Control Room systems identify constraints that are likely to be active given forecast demand and generation patterns.
 - Systems utilise zonal load flow study tools.
- 3 Control Room strategy team identify unit commitment decisions and the latest lead time for instructions.
 - Pre-Gate Closure BMU Transactions (PGBT) (including Synchronisation & De-synchronisation times). This is Likely to be instructed in Strategy timescales and accounted for in BSAD.
 - Balancing Mechanism Start Up (BMSU) – Initiated in strategy timescales – Instructions issues through BOA (by energy team).
 - Syncs without requirement to utilise BM Start Up (Instructions issued by energy team).
 - Desyncs – Instructions issued through BOA (by energy team).
- 4 Preliminary system assessment handed over to energy team.
- 5 Energy team re-evaluates system position given greater certainty of likely materiality of constraint boundaries.
 - Utilises more specific circuit assessment software.
 - Forecast of generation patterns and demand more accurate.
- 6 Strategy team hand over to Real Time team.

Real Time

- 7 Control engineer identifies specific BMU units required to resolve constraints.
- 8 Those BMU identified for constraint management have indicator assigned to them.
- 9 Every time a BOA is issued on such a BMU the appropriate flag is assigned.
- 10 Facility exists to over write flag as BOA is dispatched.
 - This functionality will be utilised rarely.
- 11 Control Room removes indicator when constraint is no longer active.

3.3.5 Advantages and disadvantages of the ex-ante constraint flagging solution

The Transmission Company representative outlined that the benefits of the methodology are that it:

- Is relatively simple in concept;
- Utilises Control Room engineering expertise to identify more complex constraint interactions; and
- Allows for the constraint management requirement to be assessed against most up to date system characteristics.

The limitations were that this methodology:

- Does not presume to identify all Bids and Offers utilised to manage transmission constraints (although it was acknowledged that it is unlikely that any ex-ante methodology would identify all transmission constraints).

The Group noted that that the methodology does not decide if an action is 'in merit'. This is done by the BSC Systems as part of the classification process. The SO will simply be flagging actions that have been constraint impacted.

3.3.6 Group views on the ex-ante constraint flagging solution

A Group member asked if an action spans across more than one half hour or, if there were two actions on the same unit, would they all be flagged? The Transmission Company representative answered that both actions in the example would be flagged. Once the 'indicator' had been set on a BMU, any BOA from that BMU would be flagged until the 'indicator' is removed.

One Group member questioned whether the process would be automated or manual. It was noted that the flag would be despatched electronically, i.e. once the 'indicator' had been set on a BMU, any BOA from that BMU would be automatically flagged. However the process for setting the 'indicator' would rely on manual input.

Another Group member questioned whether the process would be an onerous distraction for the control room operators. The Transmission Company representative indicated that the process would not be overly onerous and that, when testing, the control room operators were able to maintain a paper based system at most times, without being distracted from their principle function of balancing the system. It was only during periods where significant system balancing activities were required that the paper based test was temporarily put on hold. However, the paper based test system was more onerous than the electronic systems that would be put in place as part of a P217 solution. Additionally, if P217 was implemented, the control room operators would become far more practised in the new methodology.

One member questioned whether the Group should consider putting in place processes so that disputed constraint actions could be revised after the prices had been calculation. The Group did not believe that it would be appropriate to revise the prices, and that any inaccuracies in the SO flagging process were accepted as imperfections of the proposed solution.

One member asked whether the constraint identification criteria was the same for the strategy team and the real time team. The Transmission Company representative answered that the methodology was the same, but the information was different. As real time approaches, the SO will get a clearer view of where transmission constraints will arise, and the severity of these.

One member noted that the solution had changed from what the Group had initially discussed and envisaged. The final solution was a good evolution of the initial proposal of 'big tagging'. The Transmission Company representative agreed that the final iteration of the solution was much more dynamic and robust than had been originally envisaged.

Overall the Group considered the concept of the solution to be a positive evolution of the original 'big tagging' proposal. The solution had gone from one in which a whole area could be constraint flagged several hours before Gate Closure, to one where BOAs from individual BMUs would be flagged close to real time. Importantly, the solution would utilise the SO's expertise in identifying transmission constraints.

3.3.7 Analysis of the ex-ante constraint flagging by the SO

The SO presented the results of the ex-ante constraint flagging simulation. The days included in the simulation were 13 – 17 March 2008. Operational considerations meant that not all Settlement Periods were included in the test.

Following the simulation, an ex-post analysis of the constraint impacted actions was conducted. The purpose of comparing what the SO flagged ex-ante and what they would have flagged ex-post (with the benefit of hindsight) was to provide some indication of the accuracy of the flagging. However, perhaps of more pertinence, was to compare the impact of any inaccuracy on the main Energy Imbalance Price calculation. This is because the SO might incorrectly flag a constraint ex-ante, but this might be for a 'marginal' constraint that does not occur in real time. The classification process has been built into the solution to allow such flagged marginal constraint actions to retain their price if they are considered in merit. A key test is therefore whether the ex-ante flagging picks up the substantial constraints that distort the price.

Prices were recalculated using the ex-ante constraint flagging simulation results and the ex-post analysis results. These two sets of prices were compared alongside the live price. Overall, there were only a few occasions when the main Energy Imbalance Price differed between the ex-ante and ex-post flagging. This indicated that, for the sample size, any inaccuracies in the ex-ante flagging process were unlikely to distort the main Energy Imbalance Price.

The SO noted that the ex-post to ex-ante comparison does have some limitations. The ex-post methodology was initially developed for cost tracking, whereas the ex-ante methodology takes no account of cost. There are some instances utilising the ex-post methodology where actions were taken to resolve two issues, (one being constraints), have been considered in merit, and as such, have not been flagged for constraints but for the companion reason.

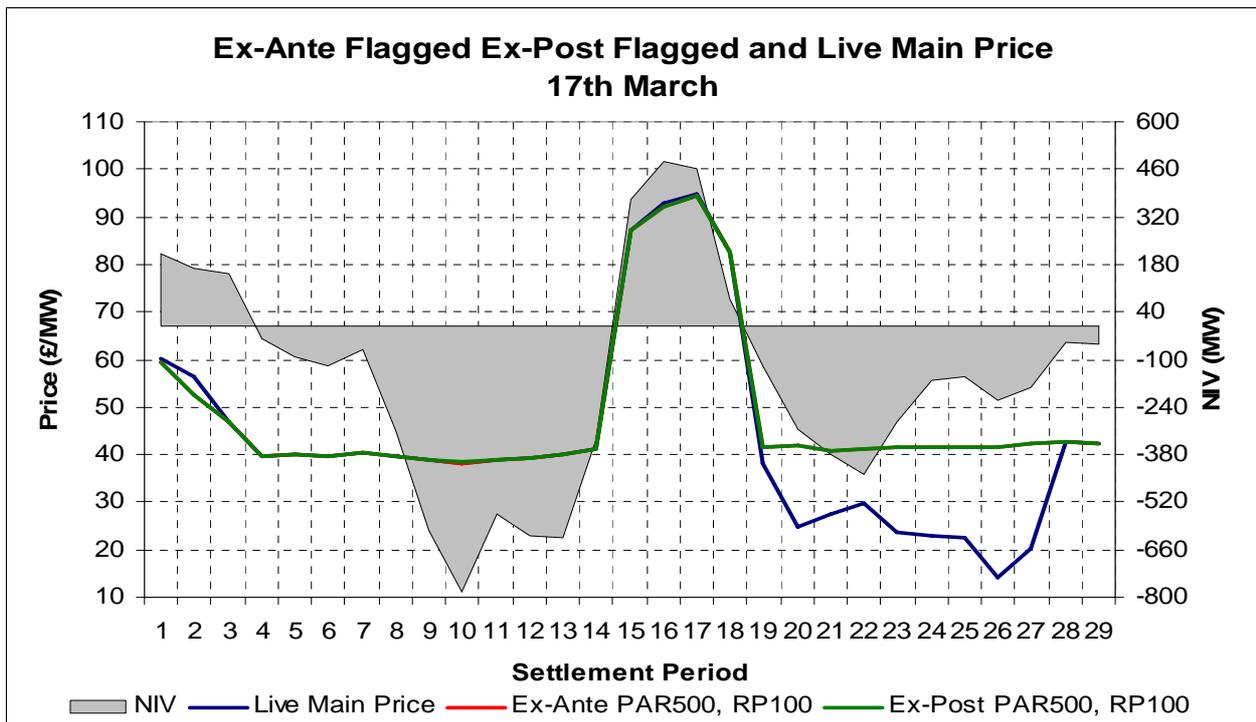
Figure 11: Table of constraint flagging results

Ex-ante and ex-post flagged analysis results						
Dates of simulation exercise	13/03	14/03	15/03	16/03	17/03	Total
Settlement Periods of simulation exercise	1 - 48	1 - 48	15 - 40	16 - 40	1 - 23	n/a
Total BOAs taken during simulation period	1,363	1,674	586	639	703	4,965
Total BOAs ex-ante flagged	83	102	87	64	76	412
Total BOAs ex-post flagged	53	40	40	18	70	221
BOAs taken for constraints not flagged ex-ante	0	2	0	0	11	13
BOAs flagged that were not for constraints	30	64	47	46	17	204
Difference	30	66	47	46	28	217
Total MWhs of BOAs taken	31,382	39,462	15,399	17,462	18,384	122,089
Total MWhs of BOAs flagged ex-ante	2,135	2,271	2,732	1,345	2,257	10,740
Total MWhs of BOAs flagged ex-post	1,712	1,061	2,043	445	2,117	7,378

Figure 11 shows that, overall, more actions were flagged ex-ante than ex-post. 412 actions were flagged ex-ante and 221 were flagged ex-post, a difference of 191. However, only 13 actions were flagged ex-post which were not flagged ex-ante. This suggested that the ex-ante solution would tend to 'over-flag' on average. However, the advantage of this was that it did identify the large transmission constraint impacted actions (even if it identified too many actions). The few price differences between the ex-ante and ex-post analysis suggested that the classification process was mitigating the impact of over-flagged actions (by allowing them to retain their price).

The SO presented results from 17 March 2008, a period where there had been divergence between the current arrangements and the ex-ante and ex-post P217 solutions.

Figure 12: Ex-ante solution, ex-post and current arrangements price comparison for 17 March 2008



It should be noted that the red ex-ante line follows the green ex-post line. Figure 12 shows that, for Settlement Periods 18 to 27, when SSP was the main price, that the impact of the transmission constraints was removed (as SSP, the price a long Party gets paid, is approximately £42 under P217 as opposed to falling to approximately £15 in the live prices). An investigation into the flagging volumes explains why.

Figure 13: Ex-ante solution, ex-post and current arrangements flagged volume comparison for 17 March 2008

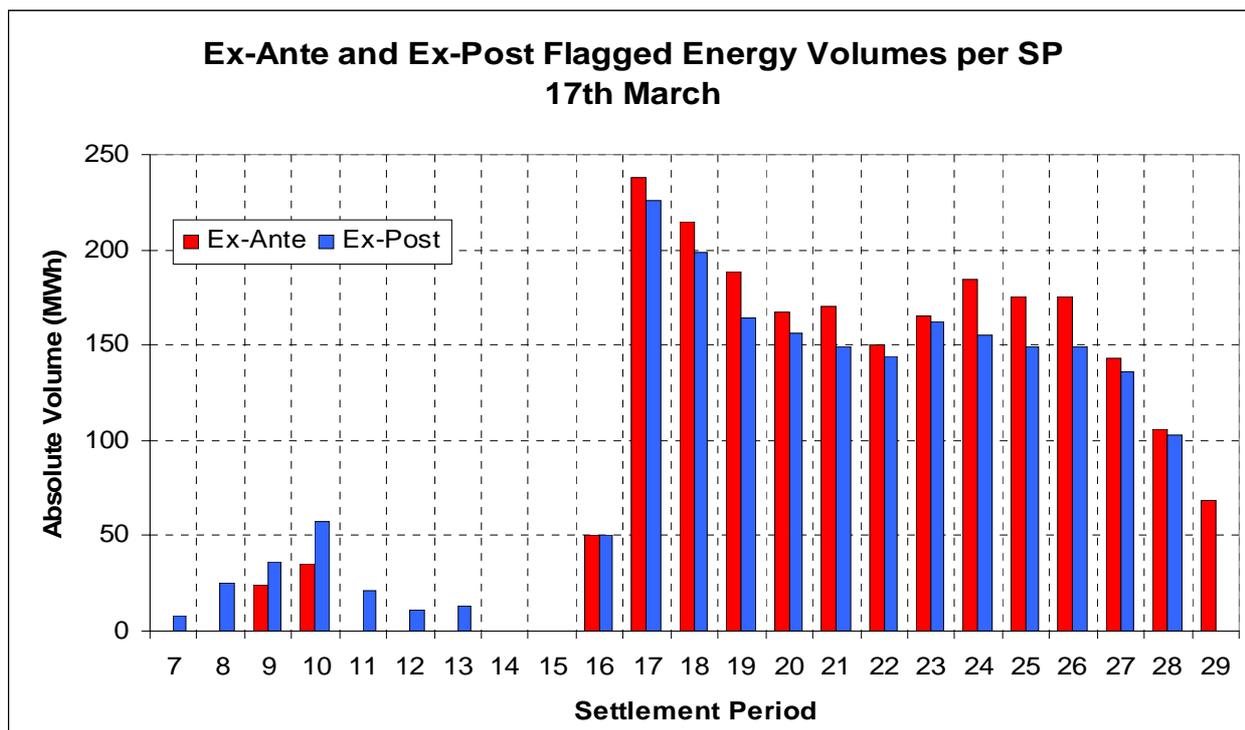


Figure 13 shows that there is a significant volume which is flagged by both the ex-ante solution and the ex-post analysis. The ex-ante solution generally over flags, however in this instance, this does not materially impact the price.

3.3.8 Group views on ex-ante constraint flagging analysis

One member commented that the ex-ante methodology was clearly over-flagging when compared to ex-post flagging. The Transmission Company representative noted that the evidence suggests that the ex-ante approach would initially over-flag on average, and that there were limitations with the methodology. However, the analysis of the results suggested that the ex-ante methodology did capture the transmission constraint actions that had the biggest impact on the price.

Another member noted that the analysis did appear to show that the obvious transmission constraints were captured. The Transmission Company representative also noted that the test conditions involved a paper based system which was inherently more onerous and less accurate than the IS based system that would be implemented. It was also noted that it would be likely that the SO ability to flag actions would improve over time as their experience improved, and performance evaluated.

Overall the Group were comfortable with the solution, although they noted the limited amount of analysis that they were able to conduct during the Assessment Procedure. It was noted by one member that this might be one reason to a PAR of 500MWh until such time that more analysis could be completed. If approved, and once the solution had been implemented, additional analysis may justify a PAR reduction, (tending towards the marginal price).

3.3.9 Governance of the SO ex-ante constraint flagging methodology

The Group agreed that the ex-ante constraint flagging methodology should sit under C16 of the Transmission License, and it would be up to the Transmission Company whether it would be included in the BSAD Methodology Statement or a new methodology statement.

The majority Group view was that, from the BSC perspective, the SO would provide a set of variables to the BSC Central Systems, and that no further obligations for constraint flagging would exist under BSC governance. They noted that this currently occurred for BSAD, any further obligations could potentially be included in the BSAD Methodology Statement. Alternatively, a new document which would sit under C16 of the Transmission License could contain the methodology. This methodology statement would be drafted during the implementation of P217.

A minority view was that the ex-ante constraint flagging solution would preferably sit under BSC governance within the Code. One member commented that this would be their preference. Another member suggested that the reasons for the BSAD Methodology Statement sitting under the Transmission Company License were historical and that the Group should not be embedding and deepening initial anomalies.

3.4 The Replacement Price

3.4.1 Conclusion

The Group agreed by majority that the Replacement Price Average Reference (RPAR) volume should be set at 100MWh and that this could only be changed via a modification to the Code. The minority view was the RPAR should be 1MWh. However, the Group request industry views on the size of the RPAR.

3.4.2 Definition Principle

The Group agreed the Replacement Price Methodology should determine prices for unpriced volumes that appear in the NIV with a price based on a volume weighted average of the most expensive 'X' MWh of non-NIV tagged priced acceptances, and the value of 'X' will be determined during the Assessment Procedure.

3.4.3 Revisiting the rationale for P194

During the Definition Procedure the Group agreed the methodology of the Replacement Price (as in Section 3.4.2 above). The purpose of the Assessment Procedure was to determine what volume of priced actions should be used to determine the Replacement Price.

The Group first called upon the methodology used for previous Modifications where a PAR volume (P194 'Revised Derivation of the Main Energy Imbalance Price' and P205 'Increase in PAR level from 100MWh to 500MWh') was set. The P194 Modification Group had used the justification that the PAR volume should not be made up of only one potentially unrepresentative action. In that case, the P194 Group had considered the average value of one BOA plus two standard deviations ($34\text{MWh} + (2 \times 40\text{MWh}) = 114\text{MWh}$). Statistically, this means that there would be at least two BOAs contained within the most expensive 114MWh of the NIV in 95% of occasions. This supported using 100MWh as the PAR volume. The Group investigated the average size of BOAs and the standard deviation. The table below shows the same analysis for the period 1 February 2007 to 31 January 2008.

	Accepted Bids	Accepted Offers	All Acceptances
Average Volume [MWh]	24	35	27
Standard Deviation	26	46	34

The P205 Authority decision for reducing the PAR level from 500MWh to 100MWh was that it had been shown that system actions were polluting the main Energy Imbalance Price calculation, and a PAR level of 500MWh mitigated this impact. Additionally, a PAR level of 500MWh still maintained strong price incentives at times of system stress.

The table above gives a volume for one BOA plus 2 standard deviations of 95MWh ($27\text{MWh} + (2 \times 34\text{MWh})$). This suggested the reasoning for using 100MWh to reduce the instances where one unrepresentative action set the price was still justifiable provided that the P217 solution removed the concerns expressed under P205.

3.4.4 Volume of unpriced actions currently in the NIV

The Group considered the current unpriced volume in the NIV. This would give them an idea of the impact of assigning this volume a Replacement Price. ELEXON analysed the period 1 February 2007 to 31 January 2008.

As seen in the table below, there are approximately 11% of Settlement Periods which contain unpriced volume. Currently this volume does not contribute to the main Energy Imbalance Price calculation (i.e. it is ignored and only priced volume is used). The maximum unpriced volume in the NIV during the analysis period was 810MWh. There were 316 instances where unpriced volume was greater than 100MWh. This is approximately 1.8% of all Settlement Periods. Additionally, there were 6 instances where unpriced volume was greater than 500MWh (approximately 0.034% of all Settlement Periods).

	NIV<0	NIV>0	All NIV
Average percentage of NIV unpriced (where there is unpriced volume in the NIV) (%)	13	24	17
Average unpriced volume in NIV (where there is unpriced volume in the NIV) (MWh)	48	69	54
Percentage of instances where NIV contains unpriced volume (for all Settlement Periods) (%)	11.34	9.86	10.74

One member commented that the unpriced volumes analysis indicated that the current calculation of the main Energy Imbalance Price was detrimentally impacted by too many actions being tagged as unpriced. This is because the NIV is the energy imbalance that the SO has to resolve, and therefore, to attain cost reflectivity, the full costs of resolving the NIV should be reflected in the main Energy Imbalance Price (and not be removed). The member’s view was that under P217 this system influence would be removed somewhat due to the Replacement Price being assigned to this volume.

3.4.5 Replacement Price Analysis of the ex-post constraint flagging data analysis results

The Group analysed the following volumes of RPAR:

- 1MWh;
- 100MWh; and
- 500MWh.

The Group noted the following conclusions:

- The Replacement Price is higher for SBP and lower for SSP the smaller the MWh level of RPAR;
- The spread of Replacement Prices is greater the smaller the MWh level of RPAR;
- The re-priced volume is generally small but in some periods can be greater than the Proposed and Alternative PAR volumes (100MWh and 500MWh respectively); and
- The Replacement Price Volume has a relatively small impact on the main Energy Imbalance Price when compared to the PAR volume.

The table below shows the average Replacement Price and Standard deviation for long and short periods:

	1MWh	100MWh	500MWh
System Short			
Average (£)	54.13	48.53	41.95
Standard Deviation (£)	40.67	33.22	22.09

	1MWh	100MWh	500MWh
System Long			
Average (£)	14.52	15.32	16.03
Standard Deviation (£)	5.08	4.72	4.47

The above table shows that the smaller the RPAR, the more expensive the Replacement Price. This occurs for all Settlement Periods as can be seen in Figure 14 and Figure 15 below:

Figure 14: Period average Replacement Prices – system short

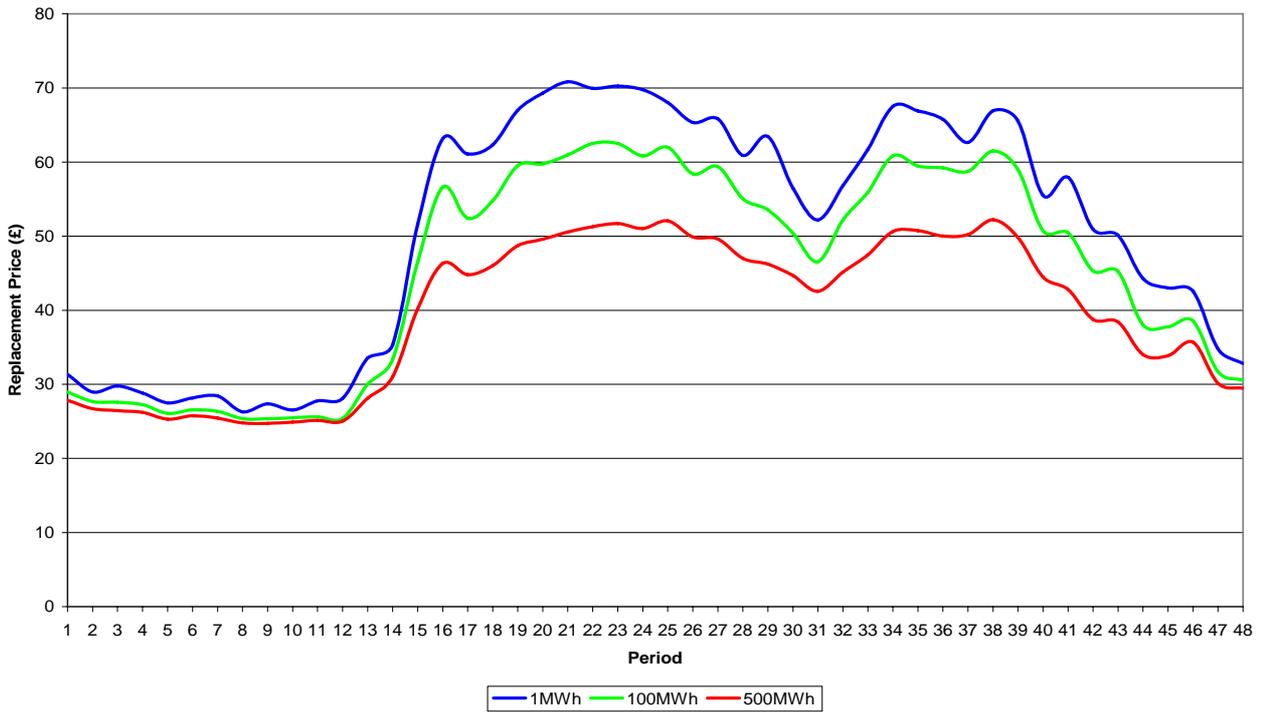
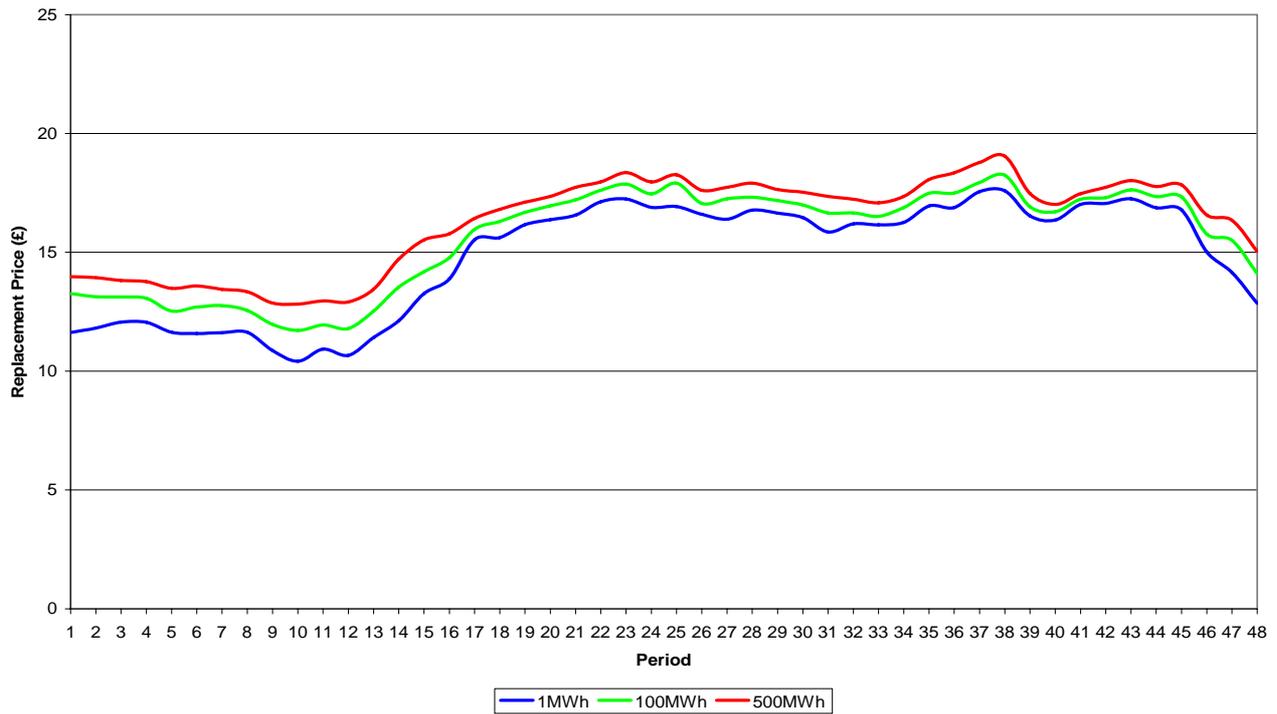


Figure 15: Period average Replacement Prices – system long



3.4.6 Replacement Price PAR volume has a small impact compared to PAR volume

The most significant finding of the Replacement Price analysis was that the RPAR volume, when averaged out over the 9 month analysis period, had a much smaller impact on the main Energy Imbalance Price than the PAR volume. Figure 16 and Figure 17 below demonstrate this. These figures show the average SBP and average SBP respectively for each Settlement Period. AS might be expected, it can be seen that the most extreme prices occur with a PAR level of 1MWh. The combination of RPAR values with a PAR of 100MWh track closely together, as do the RPAR values with a PAR level of 500MWh

Figure 16: Settlement Period average SBP for 1 January 2007 to 30 September 2007

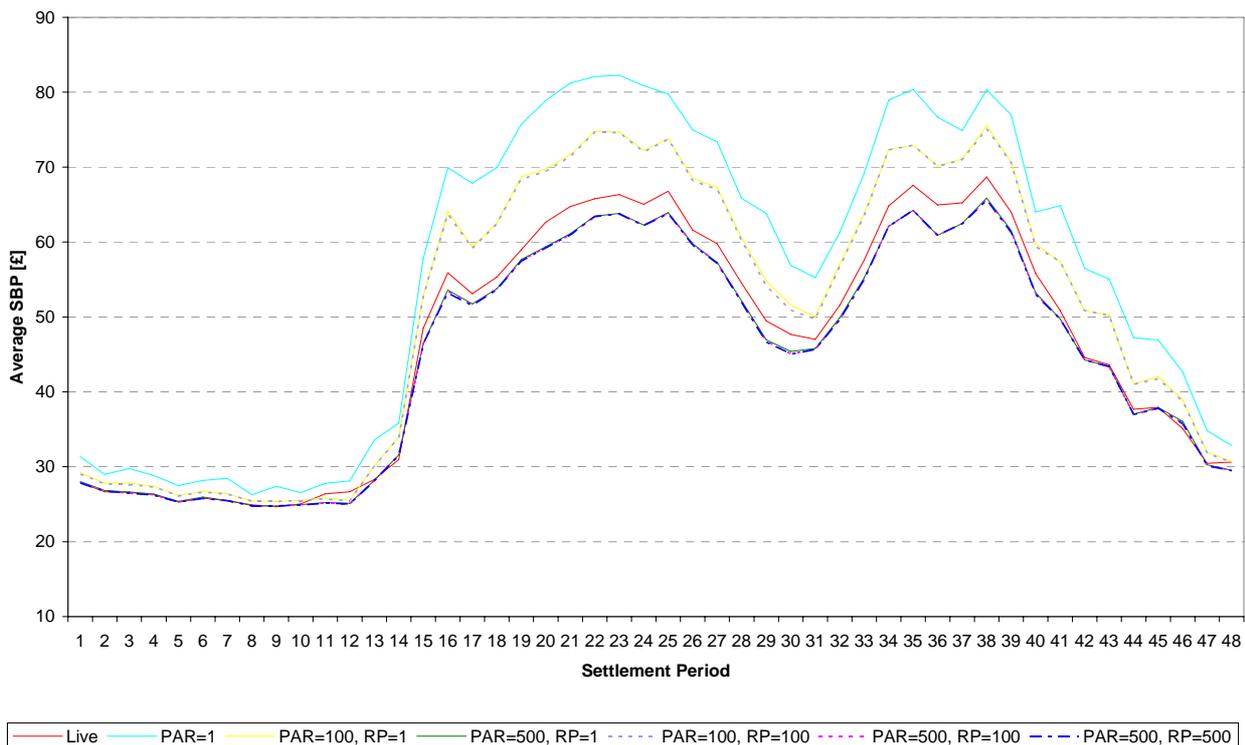
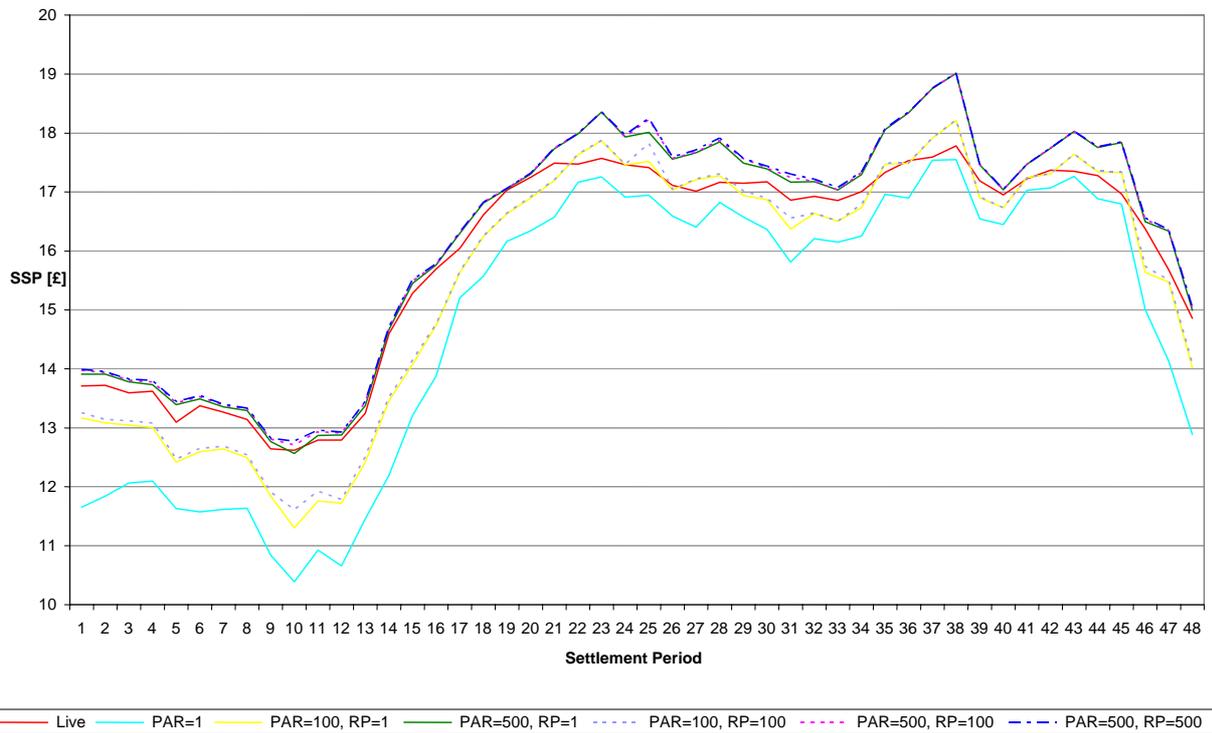


Figure 17: Settlement Period average SSP for 1 January 2007 to 30 September 2007

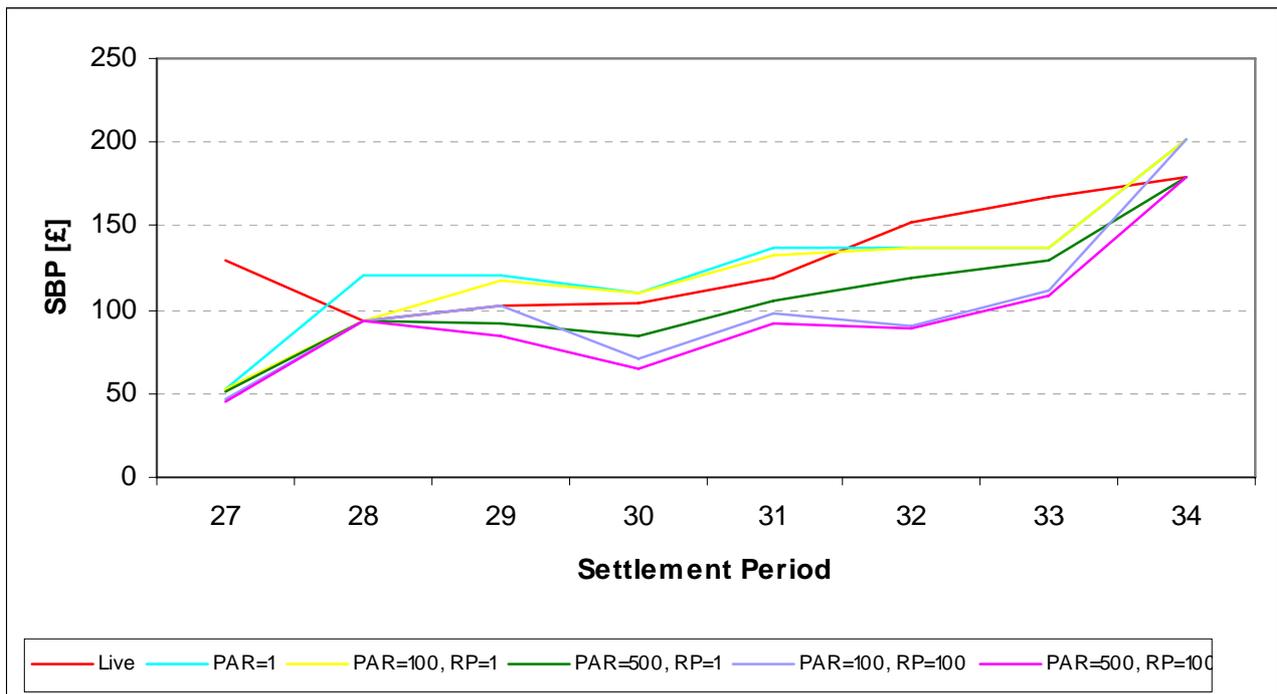


In Figures 16 and 17 above, the lines of the two scenarios where PAR is 100MWh are almost overlaid, whatever the RPAR volume used. There is a similar pattern for the scenarios where PAR is 500MWh.

However, this does not mean that the Replacement Price PAR volume is an immaterial parameter. Although over a 9 month period the Replacement Price PAR volume has, on average, little impact when compared to the PAR volume, this is not the case for Settlement Periods where certain circumstances occur.

Figure 18 shows a number of Settlement Periods on 27 September 2007. During these Settlement Periods, a large volume of transmission constraint impacted actions were flagged. Most of these actions were classified as Flagged (unpriced) and given a Replacement Price. The nature of the priced volume in the NIV meant that there were significant differences between the Replacement Price for RPAR1MWh (approximate £110/MWh) and RPAR100MWh (approximately £80/MWh). A more detailed description is included in Attachment A.

Figure 18: SBP for Settlement Periods 27 – 34



3.4.7 Group conclusions on the Replacement Price PAR volume

The Group are initially split as to whether the Replacement Price volume should be 1MWh or 100MWh, with the majority favouring 100MWh. A minority favoured 1MWh.

Arguments for 1MWh:

- A 1MWh would provide a marginal price approach. If the purpose of the Replacement Price is to assign the marginal price of energy to unpriced actions, then a volume of 1MWh should be used.
- A 1MWh Replacement Price volume simplifies the arrangements when compared to a 100MWh RPAR.

Arguments for 100MWh:

- The replacement price should not be set from a single unrepresentative action. Taking a PAR volume of 100MWh ensures that in 95% of cases the replacement price cannot be set from one unrepresentative action. This reasoning was used by the P194 Group to justify the size of the P194 PAR.
- Setting a 100MWh RPAR volume acknowledges that the SO's ex-ante constraint flagging may not be 100% accurate, and tries to mitigate that risk.

It should be noted that a number of Group members thought that a 1MWh RPAR volume would be theoretically more correct, but believed 100MWh to be a more pragmatic solution.

Consultation respondents are requested to provide views on whether the RPAR volume should be 1MWh or 100MWh. The Group noted that they were, in part, basing their initial majority view of a RPAR volume of 100MWh on the analysis undertaken for P194.

3.4.8 Alternative Replacement Price proposals

Throughout the Assessment Procedure a number of alternative proposals for the Replacement Price were discussed by the Group. Although, each one of these was discounted details of the proposals and the discussions are below.

Remove NIV tagging

One member presented a proposal to remove the concept of NIV tagging. The member noted that NIV tagging was brought in to:

- Deem the overall energy imbalance of the System;
- Use the remaining balancing actions to deem what actions were taken for System balancing purposes; and
- Then derive the main Energy Imbalance Price from the balancing actions associated with NIV.

The member noted that with P217, the Group was classifying what actions should be priced and what should be unpriced (using flagging and classification). Then the price is calculated from those actions deemed in merit. This was duplicating NIV tagging. The member suggested that completing the classification process and then NIV tagging may lead to over-tagging. They suggested that NIV tagging could be removed, and that the main Energy Imbalance Price could be calculated from the marginal 'energy' action from the larger stack of the two stacks.

The Group believed NIV tagging should be retained as it would be used to remove secondary constraint actions which would not be removed by ex-ante constraint flagging. A secondary constraint action is the equal and opposite action that is required to balance the initial primary constraint action. The ex-ante constraint flagged solution will only remove the primary action, so NIV tagging should be retained to remove the secondary action.

Issue with assuming all actions serve the same purpose and possible solutions

One member presented a paper regarding two potential issues with the Replacement Price and the classification process. This paper is Attachment H. First, there was the chance that the SO would not correctly flag constraint actions. This could lead to a misidentified high priced Unflagged (priced) constraint action setting all the flagged constraint actions below it as Flagged (priced). The member noted that they were less concerned about this eventuality after seeing the Transmission Company's ex-ante constraint flagging solution and their analysis, but that is still presented an issue.

The second potential problem was related to the assumption in the classification process that all unflagged actions provided the same service to the SO in balancing the system. The member suggested this assumption could be considered over-simplistic. In reality, energy products available were not homogenous in the eyes of the SO (due to their differing physical and dynamic characteristics). There could be a situation where an expensive unflagged BOA may be accepted because the physical or dynamic characteristics of the BMU on offer. This could result in a very small volume of energy for a particular service (e.g. peak reserve, fast response) pricing a large volume of constraint flagged actions. In the member's view, the two sets of actions were taken for different reasons and one should not be able to cause the other to retain its original price via the classification process. The member believed that although the SO would have been unable to procure the fast action BMU at a lower price, in a non-constrained market they would have been able to procure the volume of constrained actions at a lower price.

The member also highlighted the situation where the highest priced unflagged action (which priced the less expensive flagged actions in its stack) was subsequently NIV tagged out. They suggested that if this action was NIV tagged out then it was not in merit, and therefore should not be able to impact whether cheaper priced actions below it retain their price.

The member proposed three potential solutions to these problems:

1. Re-ordering NIV tagging process to before the classification process
2. Re-pricing 'in merit' flagged actions using an Ex-Post Unconstraint Schedule (EPUS)
3. Not include the classification process in the P217 solution – make all flagged actions unpriced

The member noted their preferred approach was option 2 as this was easiest to justify theoretically – developing an EPUS for priced flagged actions, although they acknowledged that this approach would require further analysis and be likely to require an extension to the timetable.

The Group considered the issues. One member noted their sympathy to the issue but thought that solving it practically would be the problem. It would be difficult to evolve a useful EPUS within the prescribed Assessment Procedure timetable. This would also significantly complicate the P217 solution.

Another member suggested that the Group had agreed that the Continuous Duration Acceptance Limit (CADL) was the appropriate way of distinguishing between short duration actions that should be flagged and unflagged actions. If an action is longer than CADL (and was not constraint flagged) then it would have been taken for energy balancing reason. If this was the case then it should be able to determine whether lower priced flagged actions retain their price.

The Group considered whether they believed the highlighted issue was a problem. The majority of the Group understood the member's concern, but did not believe it to be an issue that justified a change in the solution. Several members suggested that the proposal for a Replacement Price EPUS was overly complex and, unless it was a dynamic EPUS, then probably would have limited benefit. One member noted that if the Group wanted an EPUS as their solution then P211 and not P217 was the modification that would implement this. The proposing member commented that their modified EPUS idea would bring the benefits of P211 (removing the high priced system actions) without the drawbacks (not considering high priced actions which are in merit).

One member noted that the concerns about the Replacement Price highlighted the need to choose the correct PAR. The member believed that this problem would not occur often. However, they believed a PAR500 solution would be better at mitigating the highlighted issue than a PAR100 solution.

One member noted their support for option 3 – setting all flagged actions as unpriced. In the members view, if the SO has identified an action as constraint affected then we should set it as unpriced. It was noted that the Transmission Company had stated that their ex-ante constraint flagging solution was not attempting to define which actions were in merit, rather which actions were impacted by constraints. The danger of setting all flagged actions as unpriced was that if the SO over-flagged, then in merit actions might be excluded from the price calculation.

It was also noted, with regards to option 1, that the Group had previously suggested that one reason for having the SO directly flagging constraints was that NIV tagging might be considered imperfect. That is, it does not always remove out of merit actions and there may also be occasions when NIV tagging removes actions that should be considered energy for the purposes of price calculation.

A member noted that a potential rationale for applying NIV tagging before classification was that, if an action was outside the NIV, it should not be considered in merit, and therefore should not lead to less expensive flagged actions retaining their price if they have been flagged. This would be contrary to the Group's previous view that the NIV tagging process was imperfect at identifying constraint actions.

In conclusion the Group agreed not to include any of the proposed solutions in the final P217 solution.

3.5 The Price Average Reference volume for the main Energy Imbalance Price

3.5.1 Conclusion

The Group agreed by majority that the preferred level of the PAR was 500MWh. However, there was a minority view that the PAR should be less than 500MWh. The Group agreed that, taking account of their view, the Proposed Modification should have a PAR of 100MWh and the Alternative Modification should have a PAR of 500MWh. However, the Group request industry views on the preferred size of the PAR volume.

3.5.2 Definition principle

The main Energy Imbalance Price should be based on the current concept of a PAR volume, but the MWh volume should be reviewed during the Assessment Procedure. The PAR value should be less than or equal to 500MWh but should not be so small as to allow imbalance prices to be unduly impacted by actions which are not captured by the improved tagging methodology.

3.5.3 Ex-post constraint flagging analysis

The Group initially assessed three levels of PAR volume:

- 1MWh;
- 100MWh; and
- 500MWh.

The analysis (as has been described earlier) used 9 months of ex-post constraint flagging data and is detailed in section 4 of Attachment A. The Group concluded the following in relation to the PAR volumes:

- PAR volume has a more significant impact on the average main Energy Imbalance Prices than Replacement Price PAR volume;
- The greater the PAR volume the lower the SBP and higher the SSP (when these are the main Energy Imbalance Price); and
- Reducing the PAR volume to 100MWh, even with the removal of transmission constraint impacted actions, will still on average raise SBP and lower SSP (when these are the main Energy Imbalance Price).

Below is a table comparing prices recalculated under the Proposed and the Alternative Modifications to those of the current arrangements (or 'live'). The table shows details of the average prices, standard deviation and percentage price change from the current arrangements.

	Live	Proposed	Alternative
System Sell Price when the System is long			
Avg [£]	15.76	15.30	16.01
Max [£]	35.08	100.00	100.00
Min [£]	-6.36	-1.98	-0.03
Standard Dev	4.4	5.0	4.8
Avg % inc/dec	n/a	-3.07	1.69
System Buy Price – when the System is short			
Avg [£]	49.93	54.80	48.20
Max [£]	274.94	448.35	268.84
Min [£]	5.20	16.00	16.00
Standard Dev	30.0	38.2	27.9
Avg % inc/dec	n/a	8.58	-1.15

In addition, the Group also considered the price recalculation data broken down into specific months. The analysis is detailed in section 8 of Attachment A. The Group had the following conclusions on the price recalculation analysis:

Proposed Modification compared to current baseline

- On average resulted in higher SBP when the system is short and lower SSP when the system is long;
- There are greater peaks of both SBP and SSP;
- Constraint activity is identified and the price impact of constraints is generally removed;
- System BSAD (which is unpriced under the current arrangements) can result in lower SBPs due to entering the stack in merit order; and
- An artefact of the solution is that SSP can potentially increase substantially when the system is long. This is related particularly to SO to SO trades (see below). However, further analysis indicated that this impact may in fact be negligible.

Alternative Modification compared to current baseline

- On average resulted in lower SBP when the system is short and higher SSP when the system is long;
- There are occasions of higher SBPs (or lower SSPs) due to the nature of the methodology (due to CADL flagged and BSAD flagged actions retaining their price after classification); and

- System BSAD (which is unpriced under the current arrangements) can result in lower SBPs due to entering the stack in merit order; and
- Constraint activity is identified and the price impact of constraints is generally removed.

The Group agreed that the P217 methodology resulted in the removal of a vast majority of the impact of transmission constraints, resulting in a more cost reflective price. However, there was the potential for anomalies that were a result of the methodology. Two of these identified were:

- SO to SO trades could increase SSP; and
- Imperfections in the SO flagging could result in the classification process causing some constraint actions to retain their price (where they would otherwise have been unpriced).

SO to SO trades

The Group looked at the month of April and noted those days in which P217 (both Proposed and Alternative) resulted in much higher SSP (see figure 8.5 of Attachment A). The Group noted that such results were potentially possible given the P217 methodology allowed for in merit system BSAD trades to retain their price.

In the instances that can be seen in the graph for April (figure 8.5 of Attachment A), SSP increased to approximately £50/MWh when for most of the month this was between £10/MWh and £18/MWh. The £50/MWh SSP under the P217 methodology was the result of SO to SO trades that were flagged as system, having their price retained by the classification process. The SO to SO trades are likely to have involved the Interconnector with France. This highlighted some concern that the impact of SO to SO trades could influence the main Energy Imbalance Price such that it would be at a price level that Parties would not be able to access in the forward market.

However, the Group noted that these anomalies in the analysis could have occurred because the price recalculation did not take into account arbitrage tagging for BSAD volumes. This was because the price recalculation occurred prior to this element of the solution being agreed by the Group. **ELEXON has confirmed that the impact, once arbitrage has been applied, is removed.** All of the £50/MWh volume is removed by arbitrage tagging, and the recalculated prices are in the £10/MWh to £18/MWh range (as for the rest of the month).

Additionally, the Group noted that changes to how SO to SO trades are priced will change from late 2008. This will allow for SO to SO trades to be priced closer to real time, and therefore to be more cost reflective. The Group also noted that for the entire 9 months, this only occurred in 18 Settlement Periods.

Imperfections in the SO flagging

This issue is discussed in Section 3.4.8 above. The Group agreed that it was possible that the classification process could result in transmission constraint flagged actions retaining their price. However, the Group noted that the 9 month price recalculation indicated this would occur infrequently. On the majority of occasions when this occurred, the impact on price was to favourably remove the impact of the constraint. For example, on 29 September 2007 (Figure 8.14 of Attachment A), both the Proposed and Alternative Modification's resulted in the major impact of transmission constraints being removed.

3.5.4 Group views on the analysis

One member noted that, in this analysis, when the PAR was set at 500MWh, there was a consistent reduction in the average SBP. The member suggested this was because of the removal of actions impacted by locational transmission constraints. Another member commented that the reduction in average SBP and increase in average SSP with a PAR of 500MWh could be attributed to the introduction of the classification process.

It was noted that the data indicated that, under a P217 methodology with a PAR of 100MWh, the SBP would be higher on average than the current arrangements. It was noted that during the Definition Procedure, the Group had discussed whether a reduction in the PAR volume could be considered once the constraint based pollution of the price had been removed. The data suggested that any significant reduction in PAR volume would be likely to lead to higher SBPs and lower SSPs. A number of Group members commented that the data analysis had confirmed their suspicions, and that the important thing to note was that P217 lowered SBP when PAR was set to 500MWh.

One member noted that overall the pattern in the graphs of the P217 scenarios (as seen in Attachment A) were similar the patterns seen for the current arrangements. The Group member commented that P217 was not materially changing the methodology of how imbalance prices were calculated, rather it was trying to remove pollution by transmission constraints, and so this was to be expected. The Group noted that the data analysis suggested that P217 was less of a departure from the current methodology than P211.

3.5.5 Group view on the preferred PAR volume

The Group considered what their preferred PAR volume would be for P217. One member summarised the reasons for a PAR level of 500MWh (the current level) as set out in the P205 decision letter. The PAR was changed from 100MWh to 500MWh because of concerns about system pollution affecting the main price and a desire to retain a sharp incentive to balance. The member noted that adopting PAR500 for P217 would suggest that the Group was not confident about the constraint flagging methodology as a way for removing system balancing actions. Another member suggested that the PAR should initially be set to 500MWh, and then reviewed after 6 months.

The Group members who wanted a PAR level of 500MWh were concerned that there was only a limited sample size used for the analysis on the ex-ante constraint flagging solution. This alone was not enough to justify a reduction in the PAR level. Previously the Group had discussed whether it might be possible to reduce PAR once constraint actions had been removed from the price calculation. The 9 month price recalculation using ex-post constraint flagging demonstrated that a reduction in PAR to 100MWh would increase the average System Buy Price (SBP) and decrease the average System Sell Price (SSP) when these were the main Energy Imbalance Price respectively. However, the Group were only able to consider a limited amount of analysis for the ex-ante solution, and so were less sure of its impacts on the main prices.

A number of Group members believed that setting a PAR of 500MWh was seen as a solution that would initially be more acceptable than a PAR of 100MWh. This could potentially be revised down after some experience under the P217 arrangements proved this could be justified. That is, that the arrangements were successful in removing system actions from the price calculation. The majority of the Group reiterated that, in a perfect world, tending towards the marginal pure energy price should provide the correct incentives on Parties.

One member suggested that PAR level should be 300MWh – between 100MWh and 500MWh. In their view it should be less than 500MWh as analysis has shown that P217 should remove a good proportion of transmission constraint actions that are currently influencing price.

The majority of the Group preferred a PAR of 500MWh.

3.5.6 Proposed and Alternative Modifications

The Group discussed potential Alternative Modifications and agreed that an Alternative with a different PAR level would be appropriate. This would allow the Group to choose a more marginal approach for the Proposed Modification and a PAR level of 500MWh for the Alternative Modification. It would also allow industry to consider both options, and ultimately to ensure that Ofgem were not limited to one option. The Group unanimously agreed this way forward.

P217 Proposed: PAR volume = 100MWh P217 Alternative: PAR volume = 500MWh

3.6 The governance arrangements for the Tagging Methodology Statement and Replacement Price Methodology Statement

3.6.1 Conclusion

The Group agreed that the Tagging Methodology Statement and Replacement Price Statement should be amalgamated together to form a single document – Imbalance Pricing Guidance. Imbalance Pricing Guidance should be a guidance document that describes the calculation of the main Energy Imbalance Price in plain English. Imbalance Pricing Guidance would be drafted during the implementation period to avoid any nugatory work being conducted during the Assessment Procedure.

3.6.2 Assessment discussion of the Tagging Methodology Statement and replacement Price Methodology Statement

Prior to deciding that the Tagging Methodology Statement should become a guidance document, the Group initially discussed what form this Tagging Methodology Statement should take. One member noted that they saw it as a statement of all of the mechanics of imbalance pricing, written in plain English. The member believed that the document needs to be easily accessible by all industry people and be a one-stop shop for the Energy Imbalance Price calculation. Another member suggested it should be like a guidance note, but with stronger governance.

The Group considered whether the Tagging Methodology Statement should appear directly in the BSC, or as a Code Subsidiary Document (CSD), or as a Guidance Note. It was noted that if the Tagging Methodology Statement appear as an annex in the BSC, then it would be written in the same style as the rest of the BSC, which would not necessarily be easily accessible to all.

The Group noted that a Guidance Note would be more flexible than a CSD and would not put obligations on Parties – it would only explain how imbalance pricing works. For this reason the Group viewed that any new obligations arising in P217 should be included in the BSC. However, the Tagging Methodology Statement would be a guidance note that was referenced by the Code (in a similar way to the BSC Summary) such that ELEXON was required to produce and review it. The Tagging Methodology Statement would put into plain English the imbalance pricing mechanisms that were contained in the BSC and those areas that feed into it from other governance (i.e. BSAD).

The Group noted that if the Tagging Methodology Statement was to be a guidance note it would make sense to incorporate the Replacement Price Methodology Statement in the same document. This document would be far broader in scope than had been described in the Modification Proposal. Therefore the Group agreed to rename the document 'Imbalance Pricing Guidance'.

As a guide, the Group agreed that the Imbalance Pricing Guidance might be split into four sections:

- An introduction outlining the electricity market in Great Britain, the need to balance the system, what Energy Imbalance Prices are, and the concept of main and reverse prices;
- A detailed explanation of each flagging and tagging rule. This would also include a section on the difference between flagging and tagging, the introduction of the Bid/Offer stack and the differentiation between priced and unpriced actions. For each flagging or tagging rule there would be a plain English definition, a description of how and where the rule is defined in the Code, and an example of how the rule is used;
- An example of the whole process; and
- A section on the Reverse (Market) Price.

There would also be appendices explaining related areas such as BSAD and BSUoS charges.

The Group agreed that Imbalance Pricing Guidance should be drafted during the implementation period as the requirements would be set out in the BSC and to prevent any nugatory work being conducted during the Assessment Procedure.

3.7 Whether there would be any issues completing the proposed tagging process within the existing prompt price reporting timescales;

3.7.1 Conclusion

The Group concluded there were no issues with completing the P217 processes within the existing prompt price reporting timescales. During Definition there was initial concern that constrain flagging may cause issue with prompt price reporting. However, the SO would constraint flag in an ex-ante manner so there would be no problem with reporting within current prompt pricing timescales.

3.8 Disaggregation of BSAD

3.8.1 Conclusion

BSAD would be disaggregated. Each individual disaggregated BSAD would undergo the same tagging and classification processes as BOAs. Disaggregated BSAD would be submitted by the SO to BSC Central Systems with the price, volume and flag.

The exception to this would be a disaggregated BSAD item where the price is 'NULL'. This is intended to enable the SO to submit disaggregated BSAD volumes for certain exceptional actions (e.g., certain types of intertrip) where no cost can be allocated at the time of data submission. As there is no price the disaggregated BSAD with a NULL price would be treated as Flagged (unpriced) and would not undergo the classification process.

3.8.2 Definition Principles

BSAD should be included in the main Energy Imbalance Price calculation;

BSAD should in principle be disaggregated. This would increase transparency and it would create a consistent approach to all trades (BOAs and forward trades);

Only the price and volume of dis-aggregated BSAD should be published

3.8.3 Analysis of single trade BSAD

The Group commissioned analysis on the number of times that an aggregated BSAD variable is made up of a single trade

Analysis of the number and percentage of times a single trade makes up the entire of either system or energy BSAD was presented to the Group. Overall this occurs in approximately 35% of Settlement Periods. It was questioned whether the analysis suggests that there could be an issue as regards to disaggregating BSAD. One member noted that the analysis pointed to the fact that this statistically supported the case for disaggregated BSAD as around 2/3rds of Settlement Periods would have more accurate inputs for calculating the main Energy Imbalance Price. Another member agreed that disaggregated BSAD would be an improvement to the calculation of the main Energy Imbalance Price, but noted that there may be some behavioural consequences from disaggregating BSAD. Disaggregation of BSAD is likely to lead to market participants having a greater understanding of reserve contract prices and when the SO is a distressed buyer. This may lead some to price contracts more keenly.

One member questioned whether the issue was confined to only system BSAD. The Transmission Company representative noted that system BSAD was their primary concern. Another member suggested that there may be a case for only disaggregating energy BSAD and leaving system BSAD as aggregated. The Group

agreed that for the purposes of the price recalculation all BSAD should be disaggregated. One member commented that disaggregated BSAD would improve transparency and lead to more competitive pricing. Another member noted that the Ofgem may be called to address any issues of keener pricing under a more transparent set of arrangements.

3.8.4 Special treatment of certain disaggregated BSAD related to inter-trips

One Group member questioned whether there could be the need for some BSAD actions to not undergo the flagging process. There may be certain disaggregated BSAD actions where a price is not known (hence it would not be appropriate to consider whether the action should be priced for the purposes of imbalance pricing). Such a case could be an Emergency Instruction or an intertrip. In order to achieve this each disaggregated BSAD may need the following attributes – price, volume, flagged or unflagged, and a fourth category that would prevent the action ever being priced).

Two potential solutions were proposed:

1. Allow such actions to remain unpriced and not be subject to classification. This would either involve having adding another 'flag' to the data flow from the National Grid systems to the BSC Systems to indicate when a volume should be automatically classified 'system', or keeping the System Buy Price Volume Adjustment (SBVA) and System Sell Price Volume Adjustment (SSVA) and treat them in the same way as under the current methodology; or
2. Create some form of reference price for these unpriced volumes then treat it as a flagged action (and therefore allow it to be subject to being priced or unpriced).

The Group debated the best way forward. It was noted that the situations which would lead to an unpriced disaggregated BSAD volume were infrequent and that this should be taken into account when considering potential solutions. One member commented that they favoured assigning a reference price to such volumes so that the cost of these actions could be reflected into the imbalance price. Another member questioned how a reference price might be assigned. One member commented that they were comfortable with option 1, whereby the volume would remain unpriced. They likened these volumes to Applicable Balancing Service Volume Data (ABSVD) which cannot be included in imbalance pricing due to the need to establish prices within prompt timescales. The member suggested that an additional flag should be set by the SO to identify unpriced volumes. This should be reported in the BMRS and the SO should develop a methodology for why this 'unpriced flag' would be set. Another member suggested that such actions should not have an additional 'unpriced flag' but should instead have a NULL price.

ELEXON noted that setting a NULL price may be more efficient in terms of BSC Central Systems development. The Group agreed that a NULL should be set for situations where a volume of BSAD does not have a price. This NULL priced action would not undergo the classification process and be immediately classified as Flagged (unpriced). The rationale for why a volume would be given the 'unpriced flag' would be set out in a methodology document by the SO.

3.8.5 Comparison of aggregated BSAD and disaggregated BSAD

A comparison between P217 prices when using aggregated BSAD compared to disaggregated BSAD as per the solution was undertaken. For this comparison only periods where there was only energy BSAD were compared as the aggregated system BSAD was unpriced and so could not reflect fully the P217 solution.

The conclusions were:

- For SSP: Disaggregated BSAD resulted in higher SSP than aggregated BSAD in all cases where there is a difference; and
- For SBP: More even spread of SBP differences. The most extreme case is where aggregated BSAD results in a SBP which is £36/MWh more expensive than disaggregated BSAD.

The graphs below show frequency distributions to the nearest pound of the disaggregated prices minus the aggregated prices.

Figure 19: Frequency distribution of price differences between aggregated and disaggregated BSAD when SSP is main price

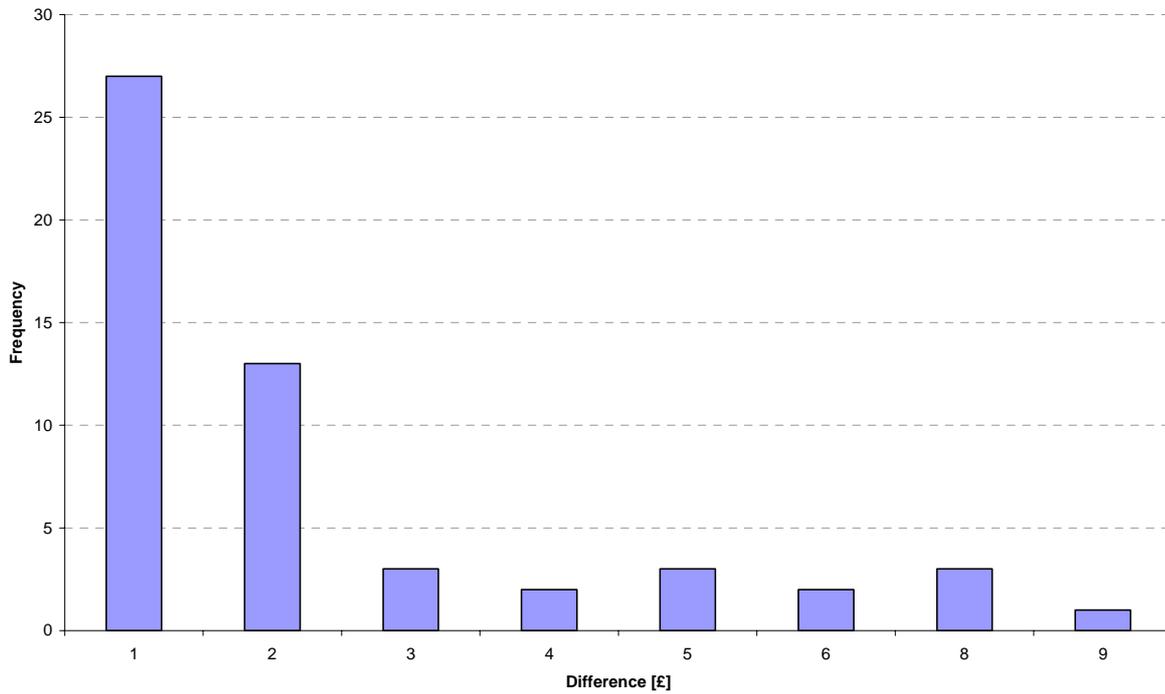
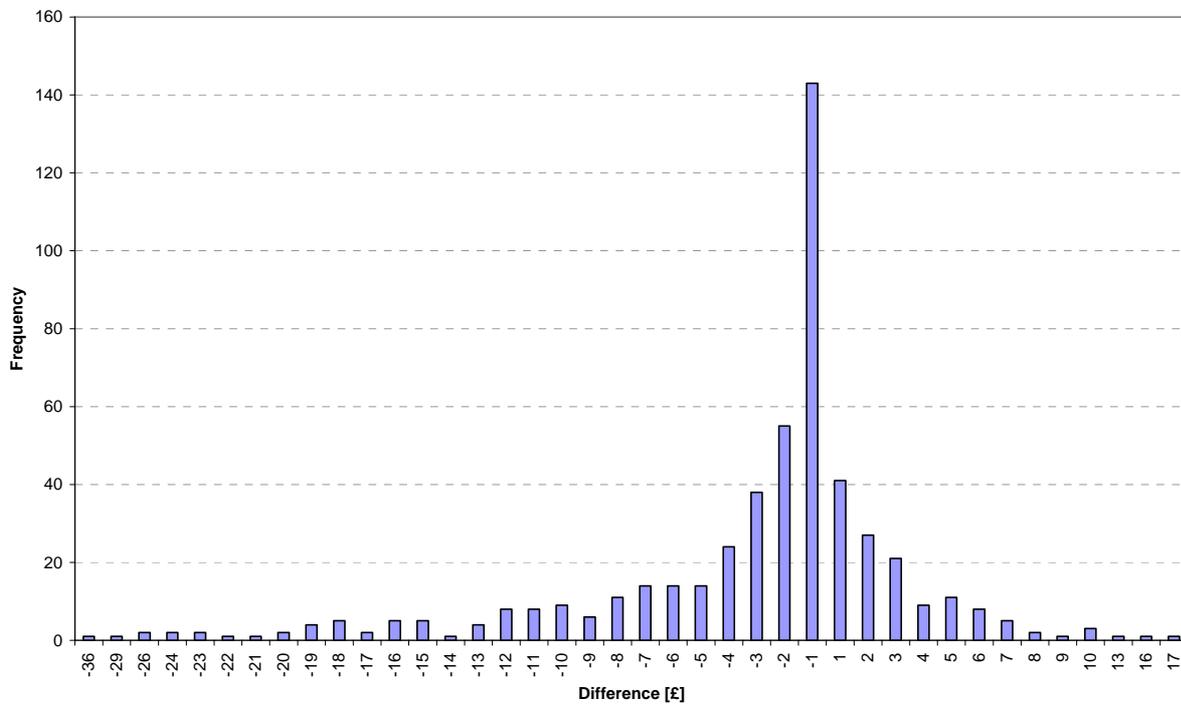


Figure 20: Frequency distribution of price differences between aggregated and disaggregated BSAD when SBP is main price



It should be noted that for the vast majority of Settlement Periods (5622 of 5676 of the SSP Settlement Periods, and 3311 of the 3824 SBP Settlement Periods) there was no difference in the main Energy Imbalance Price between disaggregated BSAD and aggregated BSAD. The Group noted these results.

3.9 The treatment of Option fees (via the BPA and SPA) in the calculation of the main Energy Imbalance Price

3.9.1 Group Conclusion

The Group concluded that the current treatment of Option fees in the calculation of the main Energy Imbalance Price should remain. For details of the current treatment of option fees see Attachment B.

3.9.2 Where the Group got to during Definition

During the Definition Procedure the Group agreed that further consideration of the inclusion of option fees in the main Energy Imbalance Price should form part of the Assessment Procedure. The Group had sympathy with the view that the current way of incorporating option fees in the main Energy Imbalance Price calculation is complex. Although no specific proposals were put forward, the Group agreed that, were a member to, bring forward a different methodology for incorporating option fees in the main Energy Imbalance Price, then time allowing, this would be considered during the Assessment Procedure.

3.9.3 Group Discussion on Option fees

ELEXON requested that any potential alternative ways of incorporating option fees be suggested by Group members. One alternative to the current treatment of Option fees was proposed. This proposal can be found in Attachment B. The proposing Group member outlined their view of what option fees should be:

- Well signalled,
- Reflect the use of reserve; and
- Allow prompt price reporting.

The member noted that 'well signalled' and 'reflecting actual use' were not necessarily compatible.

The majority of the Group agreed with these principles. One member questioned whether there would be a firm BPA published for each Settlement Period for the year ahead. Another member explained that if Option fees were well signalled, then it would be less likely that Parties would be caught out by or unable to explain BPA influenced price spikes.

One member suggested that the alternative Option fees treatment proposal was potentially a better approach. The member noted that the proposal was attempting to come up with a better way to forecast and apportion Option fees. They outlined that it was very difficult to accurately predict the use of reserve at the time that contracts were agreed. Most reserve contracts are agreed a year ahead. It was possible to predict what season reserve might be used in (the SO divides the year into six seasons), and over a season it was possible to accurately predict the reserve level required. However, day to day there could be large fluctuations in reserve use. One way around this would be to procure all reserve on a short term basis, perhaps one day ahead using a similar mechanism to the Balancing Mechanism. The member noted that there had not previously been much appetite for such a solution.

One member noted that currently Option fees were effectively treated as an 'energy' action when SBP was the main price (30% of the time) and a 'system' action when SSP was the main price (70% of the time). It was noted that this was different from the majority view of the Group that reserve was an 'energy' action.

One member suggested that the BPA could be a flat rate added to all SBP periods with no weighting for different periods. Or a percentage of the Option fee would be a flat rate and the remained of the Option fees would be allocated on the basis of historic/expected use.

A Group member questioned whether dis-aggregating BSAD would impact the treatment of Option fees. The Group noted that it would not impact the BPA and SPA and would only impact the forward trades included in BSAD.

The Group agreed that the current system for reflecting Option fees in imbalance pricing was imperfect. The Group requested the discussions be noted in the Assessment Report and agreed that, because of the time constraints and the desire to focus on the main aspects of the modification, the current treatment of Option fees should be used for the P217 solution. The Group also suggested that a discussion on Option fees should be had in another forum, such as Standing Issue 30. Finally ELEXON noted that there was nothing preventing a Party raising a Modification Proposal to alter the treatment of Option fees in Energy Imbalance Prices under the BSC.

3.10 Cashflow analysis

3.10.1 Conclusion

The Group considered the impacts on cashflows via imbalance charges and Residual Cashflow Reallocation Cashflow (RCRC). This analysis looked particularly at the impact on different sized Parties (according to BSC funding share). This is detailed in Attachment A. The Group noted that:

- The Proposed Modification resulted in an increase in RCRC of £23;
- The Alternative Modification resulted in a decrease in RCRC of £6m;

The analysis was based on historic price re-calculations and therefore did not make any allowances for changes in Party behaviour (e.g. sharper price incentives from the Proposed Modification resulting in greater incentive to balance, and therefore potentially lower imbalance charges).

- Because Imbalance Prices are generally stronger (SBP is higher and SSP is lower) under the Proposed Modification than the baseline, it is sensible to expect that those who tend to balance more accurately would be better off (as what they get back in RCRC exceeds the increase in imbalance cost). The table for the Proposed Modification indicates that this is the case for larger Parties (funding Share >3.5%).
- Because Imbalance Prices are generally weaker (SBP is lower and SSP is higher) under the Alternative Modification than the baseline, it is sensible to expect that those who tend to find it more difficult to balance would be better off (as the decrease in imbalance cost exceeds the decrease in RCRC). The table for the Proposed Modification indicates that this is the case for smaller Parties (funding Share <0.5%).

3.10.2 Analysis

The following tables show Imbalance Charges and RCRC flow calculated for the Proposed and Alternative solutions. The figures are the change from the current arrangements. Results are grouped by funding share percentages. Those parties that benefit are shown in green while the parties that are worse off are shown in red. Within the funding share percentages included in the table are all the Parent Companies whose total funding share is within the ranges in the table.

Proposed Solution

Party (by Funding Share)	Increase in Imbalance cost	Change in RCRC Received	Difference (Imb – RCRC)
0%	£0.02m	-£0.0006m	£19,900
0% to 0.5%	£1.25m	£0.35m	£909,000
0.5% to 1.0%	£0.54m	£0.66m	-£119,000
1.0% to 3.5%	£2.0m	£1.9m	£75,000
Above 3.5%	£19.5m	£20.4m	-£886,000
All	£23.3m	£23.3m	£0

This indicates that all funding share bands would face an increased imbalance cost and all Parties (other than the 0% funding share band) would see an increase in the level of RCRC received. However, smaller Parties tend to face an increased imbalance cost that is in excess of the increase in RCRC received.

Because Imbalance Prices are generally stronger (SBP is higher and SSP is lower) under the Proposed Modification than the baseline, it is sensible to expect that those who tend to balance more accurately would be better off (as what they get back in RCRC exceeds the increase in imbalance cost). The table for the Proposed Modification indicates that this is the case for larger Parties (funding Share >3.5%).

Alternative Solution

Party (by Funding Share)	Increase in Imbalance cost	Change in RCRC Received	Difference (Imb – RCRC)
0%	-£0.006m	£0.0002m	-£6,600
0% to 0.5%	-£0.53m	-£0.1m	-£438,000
0.5% to 1.0%	-£0.19m	-£0.18m	-£11,000
1.0% to 3.5%	-£0.47m	-£0.54m	£74,000
Above 3.5%	-£5.3m	-£5.7m	£381,000
All	-£6.52m	-£6.52m	£0

This indicates that all funding share bands would face a decrease in imbalance cost and all Parties (other than the 0% funding share band) would see a decrease in the level of RCRC received. However, larger Parties tend to face a decrease in imbalance cost that is outweighed by the decrease in RCRC received.

3.10.3 Group's discussion on cashflow analysis

The Group noted that the analysis seemed to support the view that smaller Parties find it more difficult to balance. Parties with a funding share of under 0.5% are worse off under the Proposed Modification when Imbalance Prices are stronger than the current baseline, and better off under the Alternative Modification when Imbalance Prices are weaker than the current baseline. However, the Group wished to re-emphasise that the historic analysis does not include any allowance for changes in behaviour. For example, were P217 Proposed in place, then the sharper incentives to balance might have reduced the level of Party imbalance, and therefore reduced their imbalance charge.

One member of the Group noted that the Alternative Modification provided weaker incentives to balance than the Proposed Modification. The member pointed out that it was potentially perverse that those Parties who find it more difficult to balance should be rewarded, as seems to be the case under the Alternative (but not the Proposed) Modification. Following on from this, it was noted that the figures in the tables were the change from the actual RCRC and imbalance charge levels for the 9 month period. However, there was no indication of the Parties initial position. Therefore, whilst a Party might be better or worse off under P217 when compared to the current baseline, they could still be receiving RCRC in excess of their Imbalance Charges. The Group noted that the total actual RCRC for the 9 month period was £ £92,097,260.43.

Another member noted that the increase cost for larger Parties of the Alternative Modification (£381,000) was not significant when spread across all players and every Settlement Period of the 9 month set of analysis.

3.11 The Group's justification for the inclusion of reserve in the main Energy Imbalance Price calculation;

3.11.1 Conclusion

The Group provided justification that reserve, in general, was taken for energy balancing means. The Group's theoretical view was that in a market with no SO, Parties would have to resolve and manage their own imbalance in order to balance the system. Even if a Party was able to perfectly balance their portfolio, and they had sufficient plant to do so, it would still be prudent for them to hold reserve. There is no guarantee that demand does not exceed a Party's forecast, or that technical difficulties may not arise, (such as plant trip), that require a Party to call on reserve. However, in a market with a SO it is more efficient for the SO to hold reserve than individual Parties. Therefore, the majority of the Group view that reserve, in general, is required to balance the short-term energy shortfalls on the System, rather than to resolve system balancing issues.

The Group noted that the solution of P217 focussed on the primary defect identified in the Modification Proposal, locational transmission constraints, and did not specifically try and identify and classify reserve actions. This was necessary to complete the Assessment Procedure within the 4.5 month timescale. However, under P217 reserve actions taken for location transmission constraint reasons would be flagged. In addition, fast action reserve actions should be flagged by the CADL mechanism.

The Group also noted that, if P217 was approved, a framework would be put in place for the Transmission Company to flag BOAs and disaggregated BSAD for reasons of locational transmission constraints. This framework could potentially be expanded by a further Modification Proposal in order to flag reserve actions as well if it was considered to be appropriate.

3.12 Cost Benefit Analysis

The Group noted that the total costs for industry are likely to be in excess of £1m. The Group were aware that it would be useful if it were demonstrated that the benefits of P217 exceed these costs.

The Group therefore believed that such a cost benefit analysis would include:

- The total industry implementation costs (a one-off cost of approximately £1m); and
- SO savings/costs via BSUoS (estimated at £4.2m per annum for the Proposed Modification and a cost of £150,000 per annum for the Alternative). These are annual figures so a net present value could be used; and
- Benefits from increased efficiency in balancing the system and competition to the market as a whole.

The Group noted that quantifying the benefits of the last point above would be subjective and a very difficult exercise. One member noted that this is perhaps of more pertinence to the Alternative Modification than the Proposed Modification given that the Alternative is expected to have an increase in BSUoS costs. One member noted that the Transmission Company had forecast costs of £133 million for managing constraints for 2008/2009. These costs could be broken down into the following:

1. £75 million forecast relating to the Cheviot constraint. This accounts for 30 weeks of outage on the Cheviot line for transmission reinforcement works, this work will also occur in each of the subsequent 3 years.
2. £39 million forecast relating to constraints activity within Scotland. A significant percentage of this cost will result from transmission reinforcement work associated with the growth of renewables.
3. £19 million forecast relating to constraint activity within England & Wales. There is also potentially an additional £5m cost to this figure, depending upon the impact on constraints resulting from the Large Plant Combustion Directive.

The Group noted that the main area the P217 sought to address was reducing the impact of constraint actions on the calculation of the main Energy Imbalance Price. The Transmission Company had forecast significant cost for managing constraints and one of the key benefits of P217 was reducing the impact of constraint costs on the main Energy Imbalance Price.

However, it is implicit in the views against the Applicable BSC Objectives that the Group believe that P217 does have benefits that will outweigh the costs (Note that all Group members preferred one of the Proposed or Alternative Modification over the current baseline, even if they did not prefer both). Therefore, whilst not quantified, it is expected that the net present value of the benefits to competition and efficient balancing the system would outweigh the one-off £1m implementation cost.

The Group wishes to obtain industry views on the overall cost/benefit of P217 in this consultation.

3.13 The required reporting under the P217 proposed arrangements

3.13.1 Conclusion

The Group agreed that they wanted as much as possible reported so that they could replicate the main Energy Imbalance Price calculation. The full reporting details are contained in section 2.3.13.

3.13.2 Definition Principle

The 'system', 'energy plus system' and 'energy' tags of accepted Bids, Offers and dis-aggregated BSAD should be published ex-post

3.13.3 Assessment discussion

The Group considered what should be reported under P217.

One member voiced the opinion that maximum transparency would lead to more efficient pricing and would allow the industry to police itself from keen pricing activities. Another member noted that greater visibility of

prices, tagging and actions may lead to a greater use of market power, keener pricing and an increase in the cost of balancing the system.

The Group agreed that they wanted as much as possible reported so that they could replicate the main Energy Imbalance Price calculation. This included for each action the:

- Original price (before tagging and replacement price);
- Volume;
- Whether it is a BOAs or BSAD;
- Whether it is has been flagged;
- Whether it is has been tagged;
- Whether replacement price applied to part or all NIV, and
- The Replacement Price

ELEXON agreed to include reporting all elements to allow the market to replicate the main Energy Imbalance Price calculation in the P217 Requirement Specification. This would include reporting these properties with the Balancing Mechanism Reporting Agent (BMRA).

3.14 Group views regarding the impact assessment responses

3.14.1 BSC Agent

The BSC Agent had provided two proposed ways of implementing the BMRS changes that would be provide under P217 – a Minimal solution and a Full solution. It should be noted that both solutions allow Parties to formulate their own Buy and Sell stacks for each Settlement Period and replicate the main Energy Imbalance Price calculation. However, the Minimal solution would require more effort by a Party than the Full solution in order to do this. For a full description of the two solutions see Attachment C. There would be no cost difference between implementing the Proposed and the Alternative Modifications.

BSC Agent	Implementation Cost	Tolerance
With BMRA Reporting: Minimal	£234,750	0%
with BMRA Reporting: Full	£253,500	0%

The Group considered whether they preferred the Minimal or the Full BMRA reporting solution. One member commented that the Full reporting route may require Parties to make more changes to their systems than the Minimal reporting solution. Another member noted that the full reporting would provide Parties with more information. This extra information would make it easier for all Parties to recalculate prices and formulate their own Buy and Sell stacks. This would reduce an existing barrier to entry – some Parties not having the resources to understand the Imbalance Pricing arrangements. On balance the Group preferred the Full Reporting option so that all Parties would be able to access the data (rather than have to complete data handling work on their systems in order to calculate the main Energy Imbalance Price and Buy and Sell stacks).

The Group believed it would be prudent for Parties to reconsider their impact assessment of P217 against the Full solution. Parties are asked to, where possible, provide this information as part of their consultation response (see question 8 of the consultation response form).

The BSC Agent also proposed an additional reporting page on the BMRS which would provide even greater visibility of the Imbalance Pricing process. It should be noted that BSCCo would look to implement this additional reporting functionality whatever the Imbalance Pricing arrangements (whether this be P217, P211

or the current arrangements). The Additional Detail Reporting option could be implemented with either the Minimal solution or the Full solution.

BSC Agent	Implementation Cost	Tolerance
Additional BMRA Detailed Reporting	£28,700	0%

The Group were supportive of the additional reporting, as long as it was a separate page that would not interfere with the BMRS data they currently captured (which would change through the Full reporting).

Therefore the total BSC Agent implementation cost would be: **£282,200**. The implementation timescale would be 35 weeks

3.14.2 BSCCo

BSCCo	Implementation Cost	Tolerance
BSCCo	£124,400	10%

The BSCCo costs are split into 270 man days or £59,400 to implement the change (update Code Subsidiary Documentation, testing and deployment), and approximately £65,000 (+/- 30% tolerance) to update the Trading Operations Market Assurance System (TOMAS) to the P217 arrangements. There would be no cost difference between implementing the Proposed and the Alternative.

BSCCo would require 8 weeks to implement P217 following the BSC Agent implementation.

3.14.3 Transmission Company

Transmission Company view of P217 against the Applicable BSC Objectives

The Transmission Company presented their analysis of P217. In general they viewed that the greater certainty of Imbalance Prices that P217 would provide (by reducing the impact of transmission constraints) would be beneficial for the efficient operation of the system.

The Transmission Company representative noted their concern that the introduction of P217 will increase market participant understanding of information relating to the location, frequency and duration of active transmission constraints. This could lead to participants around a constraint area pricing more keenly. There could also be opportunities for BSC parties with larger generation portfolios to move contracted generation load in or out of the constraint zone and exacerbate the boundary value. Such activity could require the SO to procure or sell greater levels of generation, potentially at an unattractive premium, to secure the system.

However the increased transparency of SO actions, to resolve constraints, may also act as a counter to any such changes in behaviour. It is possible that any pricing or locational load swapping activity will be visible to the general market community.

Despite this concern the Transmission Company believed both the Proposed and the Alternative better facilitated Applicable BSC Objective (b) and (c). On balance they believed that P217 Alternative was the better option as there should be a period with the new arrangements and the current PAR volume so that the impact of the arrangements can be fully understood before a reduction in PAR volume is considered.

Impact on BSUoS charges

The Transmission Company presented their initial assessment estimates of the change in system operation costs and, therefore, BSUoS costs that will occur as a consequence of the implementation of P217 or its alternative. These changes have been calculated using 2007/8 outturn costs.

Proposal	Impact on BSUoS Costs (Total BSUoS Costs approximately £705 million in 2007/8)
Proposed	-£4,162,237.24 (reduction)
Alternative	£150,079.78 (Increase)

These costs changes are due to changes in the level of costs or receipts from expected variations in NIV and changes in the relative levels of reserve requirement that will be met by the free headroom on synchronised plant. For further information on how these values were calculated and the assumptions used see Attachment E.

One member noted that, when considering only the change in BSUoS charges, the Proposed appeared to be better than the Alternative. The Transmission Company representative commented that their conclusion (that the Alternative was better than the Proposed) was based on a more holistic view of the impact of P217 on the entire market, not just the Transmission Company.

Implementation Costs

The Transmission Company representative noted P217 was estimated to cost £658,000 to implement, with £167,000 of contingency. The implementation time period for P217 was approximately 12 months, although further discussion on implementation period can be found in the following section.

The Group questioned the reasons for the Transmission Company costs and implementation period. The Transmission Company representative noted that the systems involved were the control room systems, some of the most critical that the Transmission Company operated. Therefore any changes to those systems require considerable testing and extended timescales in order to be sure the changes had been correctly implemented. The Group noted that the Transmission Company were gearing up to refresh its systems.

3.14.4 Parties and Party Agents

The Group noted that the 5 Parties that had responded had all noted medium to low impacts as a result of P217. Impact assessments had been received from 4 larger Parties and one smaller Party. The highest cost impact was £50,000, and the longest implementation period was 6 - 12 months. However, most Parties reported lower costs and shorter implementation timescales. Parties reported they would be required to change their systems to accept the new SAA IO-14 flow and the new BMRS data. It was noted that few Parties had responded. One member noted this may be a function of the low impact of P217 on Parties systems.

The Group also requested that members assess the options for BMRS change (Minimal Reporting, Full Reporting, and the Additional Reporting) and the impact on their systems.

One Party Agent responded reporting no impact.

3.15 Implementation Approach

The Group noted the longest implementation period requested was 12 months (by the Transmission company and one Party). The Group also considered that the Authority had indicated that they would be considering P211 and P217 together, and the P211 decision date was 16 October 2008. A decision date around that period would suggest the first implementation date should be the November 2009 BSC Systems Release. It was noted that the decision date did not need to be the same as P211 and could be a later date that would still allow implementation as part of the November 2009 Release. The Group therefore set the decision date as Thursday 30 October 2009, with the Implementation Date on 5 November 2009.

For the second Implementation Date BSCCo noted that the next Implementation Date they would target would be the February 2010 Release. However, the next available Implementation Date for the Transmission Company would be March 2010. The Group therefore had two options:

1. Implement the BSC changes during the February 2010 Release. The changes would not go live until March 2010 when the Transmission Company changes would be implemented.
2. Alternatively wait until the June 2010 Release so that both BSCCo and the Transmission Company can implement the changes.

The Group preferred the first option: implement the BSC changes as part of the February 2010 Release with the go-live date being set for the Transmission Company's release date in March 2010.

Therefore the implementation approach is as follows:

- 05 November 2009 if an Authority decision is received on or before 30 October 2008; or
- March 2010 (final date to be confirmed) if an Authority decision is received after 30 October 2008 but on or before 25 February 2009.

4 TERMS USED IN THIS DOCUMENT

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

Acronym/Term	Definition
ABSVD	Applicable Balancing Services Volume Data.
BMRA	Balancing Mechanism Reporting Agent.
BMRS	Balancing Mechanism Reporting Service
BSAD	Balancing Services Adjustment Data.
BSUoS	Balancing Services Use of System
Energy balancing actions	Balancing actions taken purely to increase or decrease the level of generation or demand on the Transmission System.
Main Energy Imbalance Price	The Energy Imbalance Price applied to imbalances in the same direction as the system. Sometimes referred to as the main 'cash out price'.
MaxGen	The Maximum Generation Service allows access to capacity which is outside of the Generator's normal operating range in emergency circumstances. MaxGen will be initiated in specific circumstances by the issuing of an Emergency Instruction in accordance with the Grid Code BC2.9.2.
NIV	Net Imbalance Volume.
PAR Volume	Price Average Reference Volume, the volume of actions that are used to set the Main Energy Imbalance Price.
Replacement Price	Replacement Price is assigned to unpriced actions in the NIV.
RPAR	Replacement Price Average Reference volume – a volume weighted average of the 100MWh of the most expensively priced actions remaining in the NIV. Used to calculate the Replacement Price
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.

SBP	System Buy Price.
SO	System Operator.
SQSS	Security and Quality of Supply Standards
SSP	System Sell Price.
STOR	Short Term Operating Reserve
System balancing actions	Balancing actions which are taken to balance an aspect of the Transmission System, but not because the system is short or long of energy. An example would be a set of actions taken in order to resolve a constraint on the physical flow of electricity caused by the finite capacity of the Transmission System.
TQEI	Total System Energy Imbalance Volume

5 DOCUMENT CONTROL

5.1 Authorities

Version	Date	Author	Reviewer	Reason for Review
0.1	28/04/08	Andrew Wright	Chris Stewart, Emrah Cevik	For technical review
0.2	29/04/08	Andrew Wright	Modification Group	For Modification Group review
0.3	07/05/08	Andrew Wright	Modification Group, Chris Stewart	Updated with initial views against the Applicable BSC Objectives and impact assessment responses
1.0	08/05/08	P217 Modification Group		For industry consultation

5.2 Attachments

Attachment A – P217 Analysis

Attachment B – Current treatment of Option fees

Attachment C – BSC Agent detailed impact assessment solution

Attachment D – Transmission Company Analysis

Attachment E – Transmission Company Analysis Appendix A - System Operation costs

Attachment F – Transmission Company Analysis Appendix B – Implementation costs

Attachment G – Party and Party Agent impact assessment summary

Attachment H – Paper presented by a Group member on potential issues with the Replacement Price and classification process

5.3 References

Ref.	Document Title	Owner	Issue Date	Version
1	P211 Final Modification Report	BSC Panel	05/10/07	1.0
2	P217 Initial Written Assessment	BSCCo	02/11/07	1.0
3	P217 Definition Report	P217 Modification Group	19/12/07	1.0

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: [insert hyperlink to website page containing all documents relating to the proposal]

Date	Event
19/10/2007	Modification Proposal raised by RWE npower
09/11/2007	IWA presented to the Panel
12/11/2007	First Definition Procedure Modification Group meeting held
19/11/2007	Second Definition Modification Group Meeting
14/12/2007	Third Definition Modification Group Meeting
19/12/2007	Definition Consultation issued
10/01/2008	Definition Consultation Responses returned
16/01/2008	Fourth Definition Modification Group Meeting
01/02/2008	Definition Report presented to the Panel
06/02/2008	First Assessment Modification Group Meeting
27/02/2008	Second Assessment Modification Group Meeting
29/02/2008	P211 Authority Decision - Deferred
19/03/2008	Third Assessment Modification Group Meeting
09/04/2008	Fourth Assessment Modification Group Meeting held
18/04/2008	Requirements Specification issued for BSC Agent, Transmission Company, Party and BSCCo Impact Assessment
02/05/2008	Requirements Specification Impact Assessment Responses returned
06/05/2008	Fifth Assessment Modification Group Meeting
08/05/2008	Assessment Consultation document issued to BSC Agent, Transmission Company, Party and BSCCo for consultation
21/05/2008	Assessment Consultation Responses returned
23/05/2008	Sixth Assessment Modification Group Meeting
06/06/2008	Assessment Report issued to the BSC Panel
12/06/2008	Assessment Report presented to the BSC Panel

ESTIMATED COSTS OF PROGRESSING MODIFICATION PROPOSAL ⁵

Meeting Cost	£5,000
Legal/Expert Cost	£12,500 ⁶
Impact Assessment Cost	£10,000
ELEXON Resource	194 man days £44,690

MODIFICATION GROUP MEMBERSHIP

Member	Organisation	06/02	27/02	19/03	09/04	06/05
Chris Stewart	ELEXON (Chairman)	✓	✓	X	✓	✓
Andrew Wright	ELEXON (Lead Analyst)	✓	✓	✓	✓	✓
Bill Reed	RWE npower (Proposer)	✓	✓	✓	X	✓
Rob Smith	National Grid	✓	✓	✓	✓	✓
Paul Mott	EDF Energy	X	X	✓	✓	✓ (part)
Martin Mate	British Energy	✓	✓	✓	✓	✓
Ian Moss	APX	X	X	✓	✓	X
Ben Sheehy	E.ON	✓	✓	✓	✓	X
Libby Glazebrook	First Hydro Company	✓	✓	X	✓	✓
Garth Graham	Scottish and Southern	X	X	✓	✓	X
Man Kwong Liu	Scottish Power	X	X	✓	X	✓
Bob Brown	Cornwall Energy	X	X	✓	✓	✓
Dave Wilkerson	Centrica	✓	✓	✓	✓	✓

⁵ 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.

⁶ ⁶ The above costs refer specifically to the Assessment Procedure of P217. The costs include the provision of external legal advice from DWS (£12,500). This is required due to the potential complexity of the solution of P217. It should be noted that this cost is subject to change depending on the final solution and whether an Alternative Modification is developed.

Attendee	Organisation					
David Jones	ELEXON	X	X	✓	X	X
Emrah Cevik	ELEXON	✓	✓	✓	✓	✓
Helen Boothman	ELEXON	✓	✓	✓	✓	✓
Ben Woodside	Ofgem	✓	X	X	X	✓
Ben Smithers	Ofgem	✓	X	✓	✓	✓
Adrian Palmer	Ofgem	X	X	X	✓	X
Duncan Sinclair	Ofgem	✓	✓	X	X	X
Sebastian Eyre	EDF	X	X	✓ (part)	✓ (part)	X
Andrew Colley	Scottish and Southern	✓	✓	✓	✓	✓
Neil Rowley	National Grid	✓	✓	✓	✓	✓
Lisa Waters	Waters Wye	X	✓	X	✓	X
Stephen Carter	EDF Energy	X	✓	X	✓	✓
Mark Gribble	LogicaCMG	X	✓	X	✓	✓
Stuart Cotten	Drax Power Limited	X	✓	X	X	X
Tom Selby	E.ON	X	✓	✓	X	X
Chris Barrass	Centrica	X	X	X	✓	X

MODIFICATION GROUP TERMS OF REFERENCE

1. DEFINITION PROCEDURE

- 1.1 The Modification Group will carry out a Definition Procedure in respect of Modification Proposal P217 pursuant to section F2.5 of the Balancing and Settlement Code.
- 1.2 The Modification Group will produce a Definition Report for consideration at the BSC Panel Meeting on 14 February 2008.
- 1.3 The Modification Group shall consider and/or include in the Definition Report as appropriate:
 - Principles governing the Tagging Methodology Statement;
 - Principles governing the Replacement Price Methodology Statement;
 - Principles for the treatment of BSAD, ABSVD, demand side reserve actions and imbalance on the SO accounts;
 - Interaction between P217 and other industry governance;
 - Principles for agreement of the calculation of the main Energy Imbalance Price; and
 - Scope of the required data analysis.

2. ASSESSMENT PROCEDURE

- 2.4 The Modification Group will carry out an Assessment Procedure in respect of Modification Proposal P217 pursuant to section F2.6 of the Balancing and Settlement Code.
- 2.5 The Modification Group will produce an Assessment Report for consideration at the BSC Panel Meeting on 12 June 2008.
- 2.6 The Modification Group shall consider and/or include in the Assessment Report as appropriate:
 - The detailed rules for the BSC Tagging Methodology Statement;
 - The detailed rules for the ex-ante constraint flagging methodology for identifying locational transmission constraints as developed by National Grid;
 - The detailed rules for the BSC Replacement Price Methodology Statement, including the size of the 'chunk' used to determine the replacement price;
 - Reassess the PAR volume for the main Energy Imbalance Price, as part of this reassessment the Group should first consider whether the current value of PAR500 is appropriate for the P217 solution;
 - The required governance arrangements for the Tagging Methodology Statement and Replacement Price Methodology Statement and any interaction with BSAD Methodology Statements;

- Whether there would be any issues completing the proposed tagging process within the existing prompt price reporting timescales;
- The detailed treatment of BSAD under the proposed arrangements, including its dis-aggregation, inclusion of BSAD in the main Energy Imbalance Price calculation, and the inclusion of Option fees (via the BPA and SPA) in the calculation of the main Energy Imbalance Price;
- The Group should outline its justification for the inclusion of reserve in the main Energy Imbalance Price calculation;
- The required reporting under the P217 proposed arrangements; and
- Detailed analysis of the impact on Energy Imbalance Prices.

The Modification Group will prioritise their analysis and assessment in order to complete work on the primary aspect of P217, the revised tagging rules, within the outlined Assessment Procedure period. The Assessment Procedure timetable should not be prejudiced by undertaking analysis on the remaining areas at the expense of the revised tagging rules that are considered to be secondary. For the avoidance of doubt, BSAD, Option fees, CADL and PAR level are considered secondary.

APPENDIX 3: RESULTS OF IMPACT ASSESSMENT

a) Impact on BSC Systems and Processes

System / Process	Impact of Proposed/Alternative Modification
Settlement Administration Agent (SAA) systems	The SAA system will be impacted. P217 seeks to change the derivation of the main Energy Imbalance Price. A new version of the SAA-I014 flow will also be required.
Balancing Mechanism Reporting Agent (BMRA) systems	Both the BMRS website and the TibCo Service will be impacted.

The detailed solution provided as part of the BSC Agent impact assessment is contained in Attachment C.

b) Impact on BSC Agent Contractual Arrangements

BSC Agent Contract	Impact of Proposed/Alternative Modification
LogicaCMG (BMRA, SAA)	The changes to BMRA and SAA will be reflected in the relevant agreements.
Cap Gemini (SVAAO)	None identified to date.
PwC (BSC Auditor, Certification Agent)	None identified to date. The BSC Auditor shall note the change.
IMSERV (Profile Administrator)	None identified to date.
EASL (Teleswitch Agent)	None identified to date.

c) Impact on BSC Parties and Party Agents

5 Parties that had responded to the impact assessment had all noted medium to low impacts as a result of P217. Impact assessments had been received from 4 larger Parties and one smaller Party. The highest cost impact was £50,000, and the longest implementation period was 12 months. However, most Parties reported lower costs and shorter implementation timescales. Parties reported they would be required to change their systems to accept the new SAA I0-14 flow and the new BMRS data. It was noted that few Parties had responded. One Party Agent responded stating no impact. For full impact assessment comments see Attachment G.

d) Impact on Transmission Company

The SO would submit disaggregated BSAD to BSC Central Systems.

The SO would flag Bid Offer Acceptances and disaggregated BSAD items in accordance with the methodology that is being developed in consultation with the P217 Modification Group. This is likely to have an impact on the SO's systems and processes.

There may be further impacts on the SO's systems as a consequence of the changes to the SAA I-014 flow and the BMRS.

For a full copy of the Transmission Company analysis see Attachment D.

e) Impact on BSCCo

BSC System / Process	Potential Impact of Proposed Modification
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BSC System / Process	Potential Impact of Proposed Modification
Market Monitoring	ELEXON's market monitoring processes and systems (including the TOMAS system) will be impacted.
Gatekeeper Software	The changes to SAA-I014 may impact ELEXON's Gatekeeper software.
ELEXON documentation	Industry Guidance Notes and internal documentation will require revision to reflect changes to the calculation of main Energy Imbalance Prices.

f) Impact on Code

Code Section	Impact of Proposed/Alternative Modification
Section Q 'Balancing Mechanism Activities'	Section Q will require amendment to detail the changes to BSAD and BOAs.
Section T 'Settlement and Trading Charges'	Section T will require amendment to detail the changes to the Energy Imbalance Price calculation.
Section V 'Reporting'	Section V will require amendment to detail the Reporting changes.
Annex X	Annex X will require amendment to revise existing definitions and to introduce new definitions.

g) Impact on Code Subsidiary Documents

Document	Impact of Proposed/Alternative Modification
BSCP01 'Overview of Trading Arrangements'	BSCP01 will reflect the new process.
BSCP18 'Corrections to Bid-Offer Acceptance Related data'	BSCP18 will reflect the new process. This may include an impact on Sections 3.3.12 – 3.3.18 in relation to the treatment of Emergency Instructions.
CVA Data Catalogue	The CVA Data Catalogue will reflect the new process.
Interface Definition Document (IDD)	The IDD will reflect the new process.
SAA Service Description	The SAA Service Description will reflect the new process.
BMRA Service Description	The BMRA Service Description will reflect the new process.
Reporting Catalogue	The Reporting Catalogue will reflect the new process.

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

Document	Impact of Proposed/Alternative Modification
Transmission Licence	The System Operator's flagging methodology is likely to be under the governance of the Transmission Licence. The BSAD Methodology Statement will also be impacted.

Copies of the full Core Industry Document owner impact assessment responses are attached as a separate document, Attachment [3] [delete this statement if not applicable].

i) Impact on Other Configurable Items

Document	Impact of Proposed/Alternative Modification
SAA User Requirements Specification and other system documentation	SAA documentation will require amendment.
BMRA User Requirements Specification and system documentation	BMRA documentation will require amendment.
BSC Business Process Model	The ELEXON Business Process Model will require amendment.

j) Impact on BSCCo Memorandum and Articles of Association

None identified to date.

k) Impact on Governance and Regulatory Framework

None identified to date.

APPENDIX 4 – BACKGROUND AND CURRENT ARRANGEMENTS

Background and current arrangements

Background

A BSC Party is required to pay Energy Imbalance Prices when its credited energy (e.g. metered volume or volume reallocation) does not match its notified contract volume (e.g. energy sale or purchase). Imbalance settlement, or 'cash out', is designed so that any electricity generated or consumed which is not covered by contracts is paid for at a price that reflects the short term energy costs incurred by the SO in rectifying the residual System imbalance.

When a Party is in imbalance, then this imbalance volume is paid for at System Buy Price (SBP) (if the Party is short) or receives a price of System Sell Price (SSP) (if the Party is long).

Current arrangements

Under the current baseline, actions taken by the SO to balance the System 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 overall System imbalance over a half hour Settlement Period is known as the Net Imbalance Volume (NIV), and is determined by summing the Pre-Gate Closure trades (reflected in Balancing Services Adjustment Data or 'BSAD') with the Bids and Offers accepted by the SO⁷ in the Balancing Mechanism. The system is 'long' when the volume of Bids and / or Relevant Balancing Services sales predominates and the system is 'short' when the volume of Offers and/or Relevant Balancing Services purchases predominates.

The main Energy Imbalance Price is calculated from a volume weighted average of the 500MWh of the most expensive priced balancing actions in the NIV. In order to get to the point where the most expensive⁸ 500MWh of priced actions is known a number of rules are applied to remove actions that were not taken to balance the energy on the System. These rules are known as 'tagging'. The tagging rules are processes to remove the prices of Bid Offer Acceptances (BOAs) which have been determined as those that should not be included in the main Energy Imbalance Price calculation, and therefore not targeted on those out of balance. The following tagging rules are applied:

- **De Minimis:** De Minimis tagging removes all BOAs with a volume less than the DMAT. This volume is currently set at 1MWh. This approach is intended to remove potential 'false' actions created due to the finite accuracy of the systems used to calculate Bid and Offer Volumes;
- **Arbitrage:** Where the price of an accepted Offer Volume is less than the price of an accepted Bid Volume, the matching opposing volumes deliver a financial benefit with no obvious balancing benefit. The SO effectively facilitates a market trade rather than an obvious balancing action. In this case, the corresponding volumes are excluded from the price calculation completely;
- **CADL:** Acceptance Volumes associated with Acceptances of short duration (below the Continuous Acceptance Duration Limit (CADL) currently 15 minutes) are treated as un-priced⁹ in the price calculation;

⁷ The BSAD methodology does not explicitly exclude balancing services actioned after Gate Closure, but it is current practice to exclude them.

⁸ In this context 'most expensive' is considered in relation to the benefit of the System. Offers are bought by the System for an increase in energy, thus the 'most expensive' will be the highest priced Offer. Bids are paid to the System by Parties for a reduction in energy. Therefore the most expensive Bid will be the lowest priced (or negatively priced) Bid.

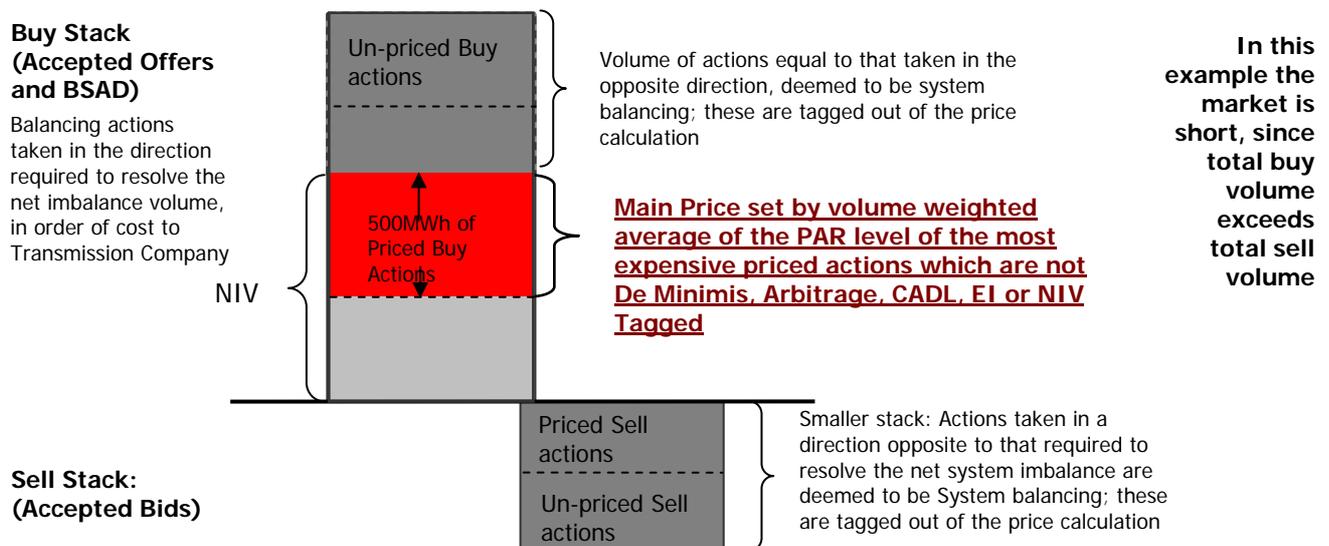
⁹ Un-priced volumes contribute to the determination of which actions set the main Energy Imbalance Price, however the costs of these actions are not included in the main Energy Imbalance Price.

- **BSAD:** The SO determines whether Relevant Balancing Services will be treated as priced or un-priced. Priced and un-priced components of BSAD are each aggregated to net¹⁰ values for use in the BSC;
- **Emergency Instructions:** On the determination of the SO, 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 calculations; and
- **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.

The main Energy Imbalance Price also incorporates a Transmission Loss Multiplier (TLM) and the price adjusters (BPA and SPA). The TLM is a factor applied to Balancing Mechanism (BM) Units BOAs in order to adjust for transmission losses. A summary of how BPA and SPA are determined, and how they are incorporated into the main Energy Imbalance Price, is included in Attachment B. A full description is given in NGC's Balancing Services Adjustment Data Methodology statement.

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 data¹¹ submitted by Market Index Data Providers.

Figure 1: Example of the Existing Arrangements main Energy Imbalance Price Calculation (Short System)



Pending Modifications related to P217

There is currently one pending Modification Proposals that seek to amend the calculation of the main Energy Imbalance Prices: P211 'Main Imbalance Price based on Ex-Post Unconstrained Schedule'.

P211 was raised on 16 April 2007 by EDF Energy. P211 proposes to amend the calculation of the main Energy Imbalance Price such that when the market is short and SBP is the main Energy Imbalance Price, then this is to be based on the least expensive Offers that the SO could have utilised on an unconstrained

¹⁰ 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).

¹¹ The Market Index Data Statement (MIDS) defines which agents can submit the required data, the data that is to be submitted and parameters used to calculate the submitted data.

system¹². Conversely, when the system is long and SSP is the main Energy Imbalance Price, then this is to be based on the least cost Bids that the SO could have utilised on an unconstrained system. This would be achieved by creating a new Ex-Post Unconstrained Schedule (EPUS). PAR tagging would then be applied to the EPUS to ensure that only the most expensive 500MWh of Bids or Offers that the SO could have utilised to resolve the energy imbalance in an unconstrained system are used to set the main price. The 'reverse' price would remain unchanged.

P211 was issued to the Authority for decision on 5 October 2007 with a Panel recommendation that the Proposed Modification should not be made. The Authority have determined that they will consider both P211 and P217 together before reaching a decision on which Modification Proposal (if any) should be implemented.

Why was P217 raised?

The Proposer raised P217 in order to improve the way the main Energy Imbalance Price is calculated. The Proposer believes that the current tagging rules do not remove actions which are taken to balance the System, rather than the energy on the system. Actions taken for reasons other than resolving the energy imbalance of the System are often described as 'system' balancing actions, rather than 'energy' balancing actions. The main energy Imbalance Price should be calculated from actions that were used to resolve the energy imbalance for the Settlement Period. An example of a 'system' balancing action would be one taken to resolve locational transmission constraints.

The Proposer believes that Imbalance Prices may not be fully reflective of the cost of resolving the short-term energy imbalance as the main Energy Imbalance Price is being polluted by system balancing actions. This gives rise to incorrect incentives to balance as a result of inappropriate market signals. This may result in an outcome in terms of total imbalance that is less economic and efficient than would be the case if cash out was not impacted by system actions.

¹² In this context, an unconstrained system is a transmission system without constraints on the physical flow of electricity, and balancing services without constraints on the notice, speed, frequency or granularity of delivery.

APPENDIX 5: CHANGES TO THE SAA I-014 FLOW

A new version of the SAA I-014 "Settlement Reports" flow would be created for each variant of the flow. The following changes would be implemented in the new version:

1. There would be a new record type for disaggregated BSAD (including an indicator showing whether or not the BSAD item was flagged by the SO). This new record type would be reported in a new section of the file and would be kept separate from existing data items. This is required to minimise the impact of P217 on market participant systems, including the SO's systems.

The new record type would also include, for each item of disaggregated BSAD, the following four types of volume: the volume that was provided by the SO; the tagged volume; the re-priced volume; and the volume that remains priced (as originally submitted by the Party).

- a. The tagged volume shall comprise all volumes that were tagged out by De Minimis tagging, Arbitrage tagging, NIV tagging and PAR tagging¹³.
 - b. The re-priced volume shall comprise the volume that remains within the NIV, has not been PAR tagged, and has been subjected to the Replacement Price process.
 - c. The priced volume shall comprise the volume that remains within the NIV, has not been PAR tagged and has not been subjected to the Replacement Price.
2. The BM Unit Period Bid Offer Acceptance record would indicate whether or not the BOA was flagged (either by the SO or by the BSC Central Systems).
 3. The BM Unit Period Bid Offer Data record would include the following eight types of BOA volume for each Bid Offer pair: the Period BM Unit Total Accepted Bid Volume, Period BM Unit Total Accepted Offer Volume, Period BM Unit Tagged Bid Volume, Period BM Unit Tagged Offer Volume, Period BM Unit Re-priced Offer Volume, the Period BM Unit Bid volume that remains priced and the Period BM Unit Offer Volume that remains priced.
 - a. The tagged volume shall comprise all volumes that were tagged out by De Minimis Tagging, Arbitrage Tagging, NIV tagging and PAR tagging.
 - b. The re-priced Volume shall comprise the volume that remains within the NIV, has not been PAR tagged, and has been subjected to the Replacement Price process.
 - c. The priced volume shall comprise the volume that remains within the NIV, has not been PAR tagged and has not been subjected to the Replacement Price.
 4. Settlement Period Information (System Period Data) record (SPI) shall include: the Total System Accepted Bid Volume, Total System Accepted Offer Volume, Total System Tagged Bid Volume, Total System Tagged Offer Volume, Total System Re-priced Offer Volume, Total System Re-priced Bid Volume the Total System Bid volume that remains Priced as Original and the Total System Offer Volume that remains Priced as Original. The equivalent of this information shall also be reported for disaggregated BSAD items.
 - a. The Total System Tagged Volume shall comprise all volumes that were removed by De Minimis Tagging, Arbitrage Tagging, NIV tagging and PAR tagging.

¹³ If a BSAD item or BOA volume is split between Tagged and non-Tagged, then only the Tagged portion shall be allocated to the relevant Tagged volume. The remaining volume shall be allocated to the Re-priced or Priced as Original volume as the case may be. The same principle applies throughout this Section.

- b. The Total System Re-priced Volume shall comprise all volumes (BOA and BSAD together) that remain within NIV, have not been PAR tagged and have been subjected to the Replacement Price.
 - c. The Total System Priced as Original Volume shall comprise all volumes (BOA and BSAD together) that remains within the NIV, have not been PAR tagged and have not been subject to the Replacement Price.
5. The Replacement Price for each Settlement Period shall be reported in the Settlement Period Information (System Period Data) record (SPI). If there was no Replacement Price for a Settlement Period, a NULL value shall be reported.
6. The RPAR value shall be reported in the Settlement Period Information (System Period Data) record (SPI). RPAR shall be reported for each Settlement Period.

For the avoidance of doubt, the six redundant BSAD variables shall continue to be populated in line with current practice.