70/010

ASSESSMENT REPORT for Modification Proposal P138

CONTINGENCY ARRANGEMENTS IN RELATION TO THE IMPLEMENTATION OF DEMAND CONTROL MEASURES PURSUANT TO GRID CODE OC6

Prepared by: Pricing Issues Standing Modification Group

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

RECOMMENDATIONS

The PSMG invites the BSC Panel to;

- **NOTE the P138 Assessment Report and NOTE that the PSMG could not reach a consensus as to whether this Modification better facilitated achievement of Applicable BSC Objectives;**
- **DETERMINE whether the BSC Panel believes, based upon the contents of this assessment report, that the Modification better facilitates the Applicable BSC Objectives:**
  - **If the BSC Panel believes that this Proposed Modification P138 better facilitates the Applicable BSC Objectives, the BSC Panel should AGREE that the Proposed Modification P138 should be made; and**
  - **If the BSC Panel does not believe that this Proposed Modification P138 better facilitates the Applicable BSC Objectives, then the BSC Panel should AGREE that the Proposed Modification P138 should not be made.**
- **AGREE a provisional Implementation Date for the Proposed Modification P138 of 3 November 2004, if an Authority determination is received on or before the 30 April 2003, or 23 February 2005 if an Authority determination is received on or before the 20 August 2003;**
- **NOTE the development and implementation costs for Proposed Modification P138 of £22,600, operational costs of £1,537 per Settlement Period affected by the Demand Control and ELEXON effort of 80 man days, with an additional 15% tolerance associated with these estimates;**

[1] The current version of the Balancing and Settlement Code (the 'Code') can be found at www.elexon.co.uk/ta/bscrel_docs/bsc_code.html

- **AGREE that Modification Proposal** Error! Unknown document property name. **be submitted to the Report Phase in accordance with Section F2.7 of the Code; and**
- **AGREE that the draft Modification Report be issued for consultation and submitted to the Panel Meeting on** Error! Unknown document property name**..**

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SUMMARY OF IMPACTED PARTIES AND DOCUMENTS

As far as BSCCo has been able to assess the following parties/documents have been identified as being potentially impacted by Modification Proposal P138.

Parties	
Suppliers	☒
Generators	☒
Licence Exemptable Generators	☒
Transmission Company	☒
Interconnector	☐
Distribution System Operators	☐
Party Agents	
Data Aggregators	☐
Data Collectors	☐
Meter Operator Agents	☐
ECVNA	☐
MVRNA	☐
BSC Agents	
SAA	☒
FAA	☐
BMRA	☐
ECVAA	☐
CDCA	☐
TAA	☐
CRA	☐
Teleswitch Agent	☐
SVAA	☐
BSC Auditor	☐
Profile Administrator	☐
Certification Agent	☐
MIDP	☐
TFLA	☐
Other Agents	
SMRA	☐
Data Transmission Provider	☐

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

Code Subsidiary Documents	
BSC Procedures	☒
Codes of Practice	☐
BSC Service Descriptions	☒
Service Lines	☐
Data Catalogues	☐
Communication Requirements Documents	☐
Reporting Catalogue	☐
MIDS	☐
Core Industry Documents	
Grid Code	☒
Supplemental Agreements	☐
Ancillary Services Agreements	☐
Master Registration Agreement	☐
Data Transfer Services Agreement	☐
British Grid Systems Agreement	☐
Use of Interconnector Agreement	☐
Settlement Agreement for Scotland	☐
Distribution Codes	☐
Distribution Use of System Agreements	☐
Distribution Connection Agreements	☐
BSCCo	
Internal Working Procedures	☒
Other Documents	
Transmission Licence	☐

Estimated cost for progressing P138 though Modification Procedures	**£ 42,300 + 80 ELEXON man days**
Cost of implementing Proposed Modification P138:	
Change specific	£17,660
Standalone Release Cost	Not Applicable
BSC Auditor Effort	£2,000
Clarification of Solution	£1,000
Additional ELEXON Demand Led Costs	Not Applicable
Operational/maintenance	£1,537 [1]
Total [2]:	**£ 20,660 + 80 ELEXON man days**

1. Note that the operational / maintenance cost is per Settlement Period affected by the Demand Control for 100 BM Units.
2. Note that the total cost does not include the operational / maintenance cost and a standalone project overhead was not quoted as P138 would be implemented as part of a BSC systems release as this is more cost effective and efficient.

1 DESCRIPTION OF PROPOSED MODIFICATION AND ASSESSMENT AGAINST THE APPLICABLE BSC OBJECTIVES

1.1 Modification Proposal

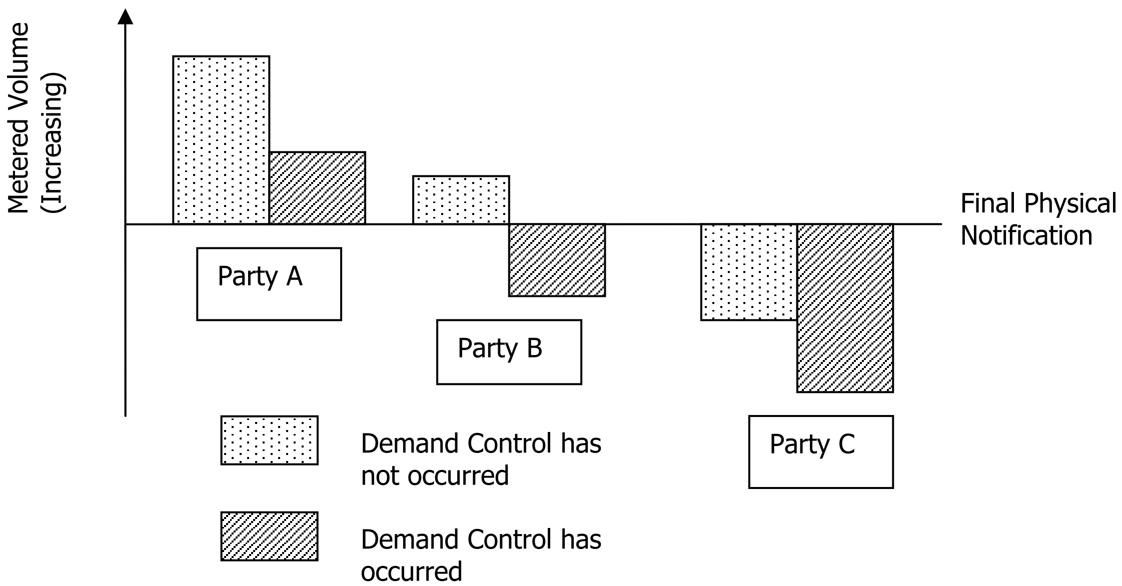
Modification Proposal P138 'Contingency Arrangements in relation to Implementation of Demand Control Measures pursuant to Grid Code OC6' (P138) was raised on 8 August 2003 by Innogy PLC. P138 aims to bring certain aspects of Demand Control within the provisions of the Balancing and Settlement Code (the Code), namely the adjustment of Energy Account volumes to reflect lost demand and the inclusion of Demand control volumes in the Energy Imbalance Price calculation.

The Panel considered the Initial Written Assessment for P138 at its meeting of 11 September 2003. The Panel agreed to submit P138 to a three month Assessment Procedure with the assessment to be undertaken by the Pricing Issues Standing Modification Group (PSMG) supported by members of the Volume Allocation Standing Modification Group (VASMG) and Licensed Distribution System Operators (LDSOs).

There are currently no provisions in the Code that relate to the impact of Demand Control measures as defined by certain provisions of the Grid Code OC6. The proposer believes that tighter system margins have increased the risk that a period of Demand Control could occur and a period of Demand Control would have a number of consequences:

- During a period of Demand Control, those parties who are affected (i.e. have their demand reduced) would have a lower Metered Volume than if the Demand Control had not occurred. This would affect their imbalance position by lengthening their position and so those parties who were short would be less short, or possibly long, and those parties who were long would be longer (as shown in Figure 1);
- The change of imbalance position created by the period of Demand Control could mean that Parties face significant costs; and
- Residual Cashflow Reallocation Cashflow (RCRC) could be high and unpredictable.

Figure 1



The Proposer therefore believes that a modification to the Code is required to include measures that will address the above issues where a Demand Control instruction is issued pursuant to Grid Code OC6; including:

- An instruction issued by the System Operator (SO) for Demand Control under certain circumstances as defined in the Grid Code OC6 would be considered to be an Offer Acceptance;
- The SO would provide details to BSCCo of the LDSO(s) that were affected by the Demand Control and approximately by what volume each LDSO was affected. These details would have been provided to the SO by LDSOs as this is a current requirement of the Grid Code OC6;
- The impact of the Demand Control upon each affected party within the GSP Group would be calculated;
- Affected Parties would receive a marginal Offer price for this Demand Control Offer; and
- Affected Parties expected Metered Volume would be adjusted by the amount identified by the relevant Demand Control Offer so that the Party's pre-Demand Control position is approximated.

The Proposer recognises that the difference between the Metered Volume if Demand Control had occurred compared to that had Demand Control not occurred could only ever be estimated, however there are various tools to aid this estimation. Primarily the information from LDSOs regarding the details of the Demand Control that has occurred could be used, and this could be supplemented by information taken from the SO's Demand Forecast and the comparison of the affected Parties Contracted and Metered Volumes. An initial estimate could be calculated in time for the Initial Interim (II) or Settlement Final (SF) run, and then further information could be added to obtain a more accurate estimate at any time up to the Final Reconciliation Run (RF) run. The Proposer also believes that if the Demand Control was carried out via a voltage reduction, deemed profiles could be used to estimate the initial volume of the Demand Control.

The Proposer believes that P138 better facilitates the following Applicable BSC Objectives:

- (b) 'The efficient, economic and co-ordinated operation by the SO of the Transmission System' by ensuring that Demand Control is utilised effectively under the Code, and by ensuring that the cost of Demand Control is appropriately incurred by NGC; and
- (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' by removing the risk of Parties being exposed to high and unpredictable Imbalance charges and potentially RCRC charges during a Demand Control Settlement Period.

The mechanism proposed for P138 is explored in section 1.2 of this Assessment Report.

It should be noted that no Alternative Modification is proposed for P138 as the PSMG could not agree on an alternative to P138 that would better achieve the Applicable BSC Objectives. Sections 1.3.6 and 6 explore this aspect in further detail.

During the Assessment Procedure for P138, the PSMG met six times, on 15 September 2003, 2, 10 and 23 October 2003 and 11 and 26 November 2003. The PSMG have undertaken one consultation and one Impact Assessment from the BSC Central Service Agent, BSCCo and the SO. The deliberations of the PSMG in respect of P138 are provided in section 6.

At its meeting of 26 November 2003, the PSMG considered the consultation responses in respect of the assessment of P138 and finalised the solutions and the recommendations in respect of the Modification Proposal. The Assessment Report for P138 was drafted to reflect the deliberations of the PSMG and was agreed by the PSMG by correspondence.

1.2 Proposed Modification

1.2.1 P138 Overview

Given the requirements of P138, the PSMG concluded that Demand Control actions should be treated as equivalent to Offer Acceptances. In order to give effect to this requirement, the PSMG considered that a number of key requirements should be introduced by the Proposed Modification:

- Where an instruction is issued by the SO for Demand Control, as defined in the Grid Code OC6, as a consequence of insufficient generation to meet demand (i.e. 6.2.1 (c), (d) and (e): Demand Reduction instructed by NGC; Automatic Low Frequency Demand Disconnection; and/or Emergency Manual Demand Disconnection), then an Offer Acceptance would be created, reflecting the volume associated with the Demand Control;
- Deemed volumes of lost demand would be calculated for all affected Parties. Details of this calculation should be included within the Code. Some of these details (i.e. estimates of the volumes of lost demand) would have been provided to the SO by LDSOs as this is a current requirement of the Grid Code OC6;
- The volumes associated with lost demand would be apportioned to affected Parties using defined volume allocation rules, which are based upon the relevant BM Unit Metered Volumes on the last equivalent day and Settlement Period for which Initial Settlement had been performed;
- Only Supplier BM Units which were importing (i.e. those beginning 2_ which had negative Metered Volume) on the equivalent Settlement Period would be included in the volume allocation rules. Therefore P138 is limited to Supplier BM Units that are importing on the equivalent Settlement Period to the Demand Control;
- Affected Parties would receive a marginal Offer Price (referred to as the Demand Control Offer Price) for the volume by which their demand was reduced (Demand Control Volume), payable by the SO; and
- Affected Parties' contracted position would be adjusted by the Demand Control Volume so that each Party's imbalance positions would be the same, whether or not the Demand Control had occurred

1.2.2 P138 Mechanism

This section describes the basic mechanism for P138. The mechanism for P138 has been split down into a number of steps:

- Notification of Demand Control;
- Initial Notification of Demand Control Volumes and Prices;
- Calculation of the Demand Control Offer Price;
- Calculation of BM Unit Deemed Demand;
- Submission of Data into Settlement; and
- Settlement Processing.

1.2.2.1 Notification of Demand Control

This process is initiated where the SO instructs the LDSOs in accordance with OC6.2.1 (c), (d) and (e). Periods of Demand Control instructed in accordance with these clauses are referred to as 'Demand

Control Periods' Note that it is assumed that the instruction to the LDSOs is synonymous with the corresponding GSP Groups.

The SO sends a notification, following each Demand Control instruction, to the Balancing Mechanism Reporting Agent (BMRA), identifying the start time of the particular Demand Control Period for each affected LDSO(s). The start time of the Demand Control Period for a particular LDSO is defined as the time the instruction to reduce demand is issued by the SO, for the relevant LDSO. Note that it is assumed that the SO will not issue a delayed instruction for Demand Control to take effect i.e. at a given point in the future, therefore it is assumed that the Demand Control instruction would take affect at the moment that it is instructed.

At some point, the SO instructs the LDSOs to start reconnecting demand, in accordance with OC6. The SO sends a notification to the BMRA following the instruction to start reconnecting demand, notifying the time of the end of the Demand Control Period for the affected LDSO(s) and, if possible, an estimate of the Demand Control Volume achieved per Settlement Period. The end time of the Demand Control Period for a particular LDSO is defined as the time the instruction to reconnect demand is issued by the SO or the start of an Electricity Supply Emergency, a Fuel Security Period or a Black Start Period.

Demand Control Settlement Periods are Settlement Periods that span the start and end times notified above and are particular to a GSP Group (LDSO). For the avoidance of doubt, where the start or end of a Demand Control Period falls part way through a Settlement Period, then the whole Settlement Period is a Demand Control Settlement Period. For example, if Demand Control was called in GSP Group X (LDSO X) at 9.50 (i.e. within Settlement Period 20) and then called off at 10.50 (i.e. within Settlement Period 22) and Demand Control was called in GSP Group Y (LDSO Y) at 10.20 (i.e. within Settlement Period 21) and called off at 11.50 (i.e. within Settlement Period 24) then Settlement Periods 20, 21 and 22 would be Demand Control Settlement Periods within GSP Group X (LDSO X) but Settlement Periods 21, 22, 23 and 24 would be Demand Control Settlement Periods within GSP Group Y (LDSO Y).

1.2.2.2 Initial Notification of Demand Control Volumes and Prices

As soon as practicable, the SO publishes a system warning message on BMRA providing an estimate of the Total Demand Control Volume for each Demand Control Settlement Period, the affected LDSO(s) and the Offer Acceptance with the highest price, which were taken or utilised in the Settlement Period within which the first Demand Control actually instructed and which:

- Has an Offer volume in excess of 1MWh;
- Which on its own or as part of a number of Acceptances that has an instruction length greater than the Continuous Acceptance Duration Limit (CADL); and
- Is not itself a Demand Control Offer.

The SO calculates the total volume of energy that it deems to have been lost due to the Demand Control as a MWh per Settlement Period per LDSO value and passes this information onto the Settlement Administration Agent (SAA), by Settlement Day + 2 (Business Days) at the latest. This communication would be via email.

The SAA would match the LDSO to the relevant GSP Group so that the SAA has the details of the total Demand Control Volume (MWh) per Settlement Period per GSP Group. The LDSO to GSP Group mapping details will have been provided to SAA by BSCCo.

The Demand Control Volume for each Settlement Period as notified to the SAA by the SO by Settlement Day + 2 (Business Days) will be deemed to be correct, aside from any manifest error. If there is such a manifest error in the SO notifications, the SO will have the discretion to correct the data.

Any Settlement Period falling wholly or partially between the time the SO instructed Demand Control to start and the time the SO instructed Demand Control to finish or the time the Demand Control was deemed to end as a consequence of the start of another situation (i.e. Electricity Supply Emergency, Fuel Security Period or Black Start) will be defined as a Demand Control Settlement Period.

1.2.2.3 Calculation of the Demand Control Offer Price

By the Initial Interim (II) run, the SAA calculates the Demand Control Offer Price. The Demand Control Offer Price would be the Price of the Accepted Offer accepted or utilised in the Settlement Period within which Demand Control occurred (note that this does not include BSAD), with the highest Offer price which:

- Has an Offer volume in excess of 1 MWh;
- Which on its own or as part of a number of Acceptances that has an instruction length greater than the CADL; and
- Is not itself a Demand Control Offer.

Note that the Offer setting the Demand Control Offer Price may have been taken in the same Settlement Period within which Demand Control was invoked, but equally may have originally been taken in a Settlement Period prior to the Settlement Period within which Demand Control was invoked, but for which the instruction is ongoing in the Settlement Period within which Demand Control was invoked. The Demand Control Offer Price would be used in all subsequent Settlement Periods which were subject to the same period of Demand Control. If two periods of Demand Control called in different GSP Groups overlapped then the Demand Control Offer Price would be the same for both periods of Demand Control. If two periods of Demand Control were called but did not overlap, then separate Demand Control Offer Prices would be calculated for each period of Demand Control.

If there are no such Accepted Offers meeting the criteria defined, then as a default, the Market Index Price would be used as the Demand Control Offer Price. If there was also no Market Index Price for that Settlement Period, then the Demand Control Offer Price would default to the Energy Imbalance Price derived from a volume weighted average of balancing actions in the Net Imbalance Volume (NIV) (as calculated in accordance with Section T4.4.5(a) or T4.4.6(a) as the case may be. Note that this is the same value to which reverse price defaults when it is zero).

1.2.2.4 Calculation of BM Unit Deemed Demand

The volume allocation rules described will be used to apportion the Demand Control Volume across all importing Suppliers in the affected GSP Group by the SAA.

For the avoidance of doubt, these volume allocation rules will be applied no matter by which relevant method demand is reduced (within the previously defined constraints).

The volume allocation rules will only apply to Supplier BM Units (i.e. those with IDs beginning '2_') that are importing in the given Settlement Period (i.e. which have negative consumption on the equivalent day used in the following volume allocation rules). Exporting BM Units (regardless of type) and directly connected demand are excluded from this calculation.

The Demand Control Volumes should be calculated for each GSP Group, for each Settlement Period within which Demand Control occurred.

To calculate the Demand Control Volume for each Settlement Period of Demand Control:

- Identify the most recent day d' which has the same day of the week as the Settlement Day d, and for which Initial Settlement has been performed and which is not a clock change day (i.e. the equivalent day as defined in section T4.2.2 (d)).
- For the Settlement Period(s) in which Demand Control occurred on day d, identify the corresponding Settlement Period j' on the equivalent day d'. This mapping process is

straightforward (period 1 mapping to period 1, period 2 mapping to period 2, and so on), except in the case where day d is a clock change day. In this case the default rules set out in T4.2.2(c) should be followed to determine the mapping.

- If the Metered Volume apportioned to a particular BM Unit in Settlement Period j' and day d' is zero, then the Metered Volume for that BM Unit from Settlement period j'-1 from day d' is substituted to be the Metered Volume for Settlement Period j'. (Note if the Metered Volume in Settlement Period j'-1 is zero, then a value of zero is used for Settlement Period j in the calculation.)
- If the Metered Volume for a BM Unit in period j' of day d' is positive (i.e. the BM Unit is exporting), then a value of zero is used for Settlement Period j in the calculation.
- Sum the Metered Volume of all the BM Units i, in the affected GSP Group in day d' and Settlement Period j' (to give $\sum_i QM_{ij'}$).
- Divide the Metered Volume of each BM Unit i, in day d' and Settlement Period j' by the total over the GSP Group (as calculated above) to give the proportion of demand per BM Unit throughout the GSP Group (to give $PDC_{ij} = QM_{ij'} / \sum_i QM_{ij'}$).
- Multiply this value obtained by the Total Demand Control Volume ($TQDC_j$; as notified by the SO by Settlement Day + 2 (Business Days)) and the Transmission Loss Multiplier Value to give the volume that should be added onto that BM Unit to take account of the Demand Control (i.e. $QDC_{ij} = PDC_{ij} * TLM_{ij} * TQDC_j$).
- Then multiply this volume by the Demand Control Offer Price ($DCOP_j$) to give the amount that the SO will pay the Lead Party of each affected BM Unit i (i.e. $CVDC_{ij} = VDC_{ij} * DCOP_j$). Note that this will be considered equivalent to an Acceptance of an Offer at the Demand Control Offer Price and should, therefore, comprise an additional element of the SOs BM Cashflow ($CSOBM_j$).

Note that this calculation would have to be carried out separately for each Settlement Period affected by the Demand Control. The SO will report a MWh figure of Total Demand Control Volume for each Settlement Period affected by the Demand Control.

Note that this calculation is carried out once and does not alter as more information becomes available in each Settlement Run.

For the avoidance of doubt no specific processing is required to account for Bank Holidays i.e. volumes for a Bank Holiday Monday will be estimated in the same way as those for a Working Day, as per T4.2.2 (d).

1.2.2.5 Submission of Data into Settlement

For each demand Control Settlement Period, defined above (i.e. which, for a given GSP Group, falls within a Demand Control Period), the SAA shall include the Demand Control Offer Volume for each affected BM Unit in the Energy Imbalance Price calculation, at the Demand Control Offer Price, (i.e. placed into the Offer / Buy stack).

1.2.2.6 Settlement Processing

Once this data is entered into settlement, the following apply:

- The Demand Control Offer Acceptance will be allocated to the relevant BM Unit and the cashflow for the Demand Control Offer Volume will be paid to the lead Party of the relevant BM Unit by the SO;
- The deemed Offer Acceptance will contribute to the calculation of System Buy Price (SBP) and will be treated along with all other Accepted Offers (except that CADL tagging will be applied only to

the Total Demand Control Volume not the Demand Control Volume applied to the individual Supplier BM Units. This means that if the Total Demand Control Volume has a duration of less than the CADL, it will be tagged out, however if the Total Demand Control Volume has a duration of more than the CADL, none of it will be tagged out, even if part of it is attributed to a Supplier BM Unit that has had another acceptance in one of the Demand Control Settlement Periods that has been subject to CADL tagging);

- The imbalance position (i.e. the calculation of Energy Imbalance for each energy account) of the affected Supplier would be corrected for those Demand Control Offer Volumes;
- The position of the impacted parties in the Energy Contract Volume Aggregation Agent (ECVAA) would be corrected for the correct calculation of Credit by a manual modification to the relevant flow; and
- Non Delivery Rules would not be applied to the Demand Control Offer Volumes.

1.2.3 Cash Flow Modelling Examples

As part of the analysis carried out to evaluate the impact of P138 on industry parties, a model has been developed to highlight the main cash flows that would result from the implementation of P138. This model has been developed to give an indication of magnitude and direction of cash flows rather than to calculate the specific financial position in which a given party may find itself. It has assumed a market consisting of five Suppliers, four generators, and four GSP Groups.

The model covers the cash flows associated with the Demand Control Offer payment, imbalance cash out, Residual Cashflow Reallocation Cashflow (RCRC), and Balancing Services Use of System (BSUoS) charges.

The results of the analysis are largely influenced by the assumptions that are made. The full details of the calculations performed are included in Annex 8. Eight examples of Settlement Periods where there had been Demand Reduction Imminent (DRI), High Risk of Demand Reduction (HRDR), or Notification of Insufficient System Margin (NISM) warnings were used with the associated prices (i.e. SBP, Market Index Price and Demand Control Offer Price) for those Settlement Periods. The calculations show the increase or decrease in payments made (including Payment for the Demand Control Offer, imbalance charges, RCRC and BSUoS) by each Party under P138 arrangements compared to current arrangements.

The model demonstrated that in most cases all generators would suffer increased charges if P138 was implemented, whether they were short or in a balanced position, due to the increased BSUoS charges. The model also demonstrated that in most cases, Suppliers that did not use any demand in the GSP Group within which the Demand Control was carried out would also suffer increased charges due to the increased BSUoS charges. Furthermore, the Model demonstrated that in some cases, a Supplier that was short, who had used demand in the GSP Group within which Demand Control was invoked would sometimes suffer increased charges but would sometimes gain due to the Demand Control, depending on the relative difference in the Demand Control Offer Price (at the Marginal Price) and SBP including, and not including the Demand Control Offer. In only one example, the Supplier who was short and who had demand takers in the GSP Group within which Demand Control was invoked suffered increased charges. This was due to the SBP without the Demand Control Offer being very low compared to the SBP including the Demand Control Offer.

1.3 Issues raised by the Proposed Modification

The PSMG considered all the issues raised in the Panel set Terms of Reference for P138 and additional other issues, all of which are addressed in the following sections.

1.3.1 Demand Control Trigger

The trigger point (i.e. start of the Demand Control Period) was determined to be the time that the first instruction by the SO to initiate Demand Control in accordance with OC6.2.1 (c), (d) and (e) was given, (note that a Demand Control instruction in accordance with OC6.2.1 (a) and (b), relating to actions taken by LDSOs, is excluded from P138). The end point of the Demand Control Period was determined to be the time the instruction was issued by the SO in accordance with OC6 to begin restoring the demand or the start of an Electricity Supply Emergency, fuel security Period or Black Start Period. The PSMG also recognised that although it would be desirable that such instructions would be specific to an LDSO and a particular GSP Group, the SO would not be able to relate the LDSO to a specific GSP Group. Therefore, the provisions of P138 would apply on an LDSO area specific basis (which the PSMG considered to be equivalent to GSP Groups, for the foreseeable future, recognising that under Approved Modification P62 'Changes to Facilitate Competitive Supply on the Networks of New Licensed Distributors', it is now possible for an LDSO to operate 'out of area'). LDSO – GSP Group mapping details would be provided by BSCCo to the SAA. The PSMG also recognised that if other emergency measures were invoked (such as an Electricity Supply Emergency, under the Electricity Supply Emergency Code or a Fuel Security Period), these would override the P138 arrangements, effectively also constituting an end point to the Demand Control Period. Demand Control Settlement Periods would then be defined as Settlement Periods that span the start and end time notified by the SO, i.e. where the start or end of a Demand Control Period falls part way through a Settlement Period, then the whole Settlement Period is considered to be a Demand Control Settlement Period.

1.3.2 Scope

The scope of the P138 arrangements should cover importers in a GSP Group (with some exceptions), i.e. all Supplier Balancing Mechanism (BM) Units which are importing when the deemed Demand Control Offer is calculated. Hence, it would be necessary to exclude any Supplier BM Units exporting in the Settlement Period used to calculate the Deemed Demand such as SVA registered generators (embedded generators). Directly connected demand would also not be within the scope of the P138 arrangements. The PSMG considered that, in the case of directly connected demand, there would be a greater likelihood of them participating in the Balancing Mechanism or having entered into other contracts with the SO to reduce demand and, hence, there was no need to try and encompass this demand in the scope of the proposal. The PSMG also concluded that although the solution to P138 did not include embedded generation, this would be outside the scope of P138, and P138 would not, discriminate against embedded generation.

The PSMG also recognised that Demand Control could involve both local and national load shedding and that it might be difficult to distinguish between Demand Control required for system balancing purposes and Demand Control required for energy balancing purposes. However, the PSMG concluded that, in any event the P138 mechanism should be invoked and then the system-energy tagging arrangements in the imbalance price cash-out mechanisms would, in effect, make that distinction (i.e. that CADL and NIV tagging make the system-energy differentiation and may remove the Demand Control Offer). Either way, the demand being reduced would and should still receive payment.

1.3.3 Demand Control Offer Price

The appropriate price for payment of lost demand / Demand Control (Demand Control Offer Price) was a key consideration of the PSMG. Proposed Modification P138 stated that the Demand Control Offer Price should be a marginal price as this would reflect the cost of the next action that the SO could have taken within the Balancing Mechanism had other actions been available instead of the necessity for Demand Control. The PSMG concluded that the most appropriate marginal price was the highest priced Accepted Offer with a volume greater than 1 MWh (effectively removing those Offers that would be De-Minimis tagged) and a duration longer than 15 minutes (effectively removing those Offers that would be tagged out by the CADL) in the first Settlement Period of the Demand Control, since the price of Demand Control should be a price that reflects this action (i.e. the last energy balancing action taken by the SO before the Demand Control occurs). The Demand Control Offer Price derived from the Settlement Period within which Demand Control was invoked would be used for all Settlement Periods which were subject to the same period of Demand Control. The PSMG noted that, under the current trading arrangements, there is no explicit payment for Demand Control, but the resulting change to imbalance implied that a Supplier would either receive an increment of System Sell Price (SSP) (if length / spill were increased by lost demand), or a decrement of SBP (if length / shortfall were reduced by lost demand). The treatment of Demand Control as a volume equivalent to an Offer would address this issue.

1.3.4 Defaults

Where there is no marginal offer price to use as the Demand Control Offer Price, the PSMG considered that the defaults should reflect those used for imbalance pricing. Hence, in the absence of an Offer meeting the relevant criteria, the Market Index Price should be used, and in the event that there is also no Market Index Price, the Demand Control Offer Price would default to the Energy Imbalance Price derived from a volume weighted average of all balancing actions in the NIV i.e. the 'main' price and the same value that the Market Index Price defaults to when it is zero.

1.3.5 Price Signals

Since the payment for the deemed Demand Control Offer (at the Demand Control Offer Price) would be included in the imbalance calculation price for the Demand Control Settlement Period, the main Energy Imbalance Price for that Demand Control Settlement Period would then also tend toward a the Demand Control Offer Price, particularly where it is marginal. Hence, any of those Parties that were short (and therefore could be said to be causing the Demand Control) would likely be exposed to a higher SBP. The PSMG considered that this could give Parties a greater incentive not to be short in order to avoid exposure to imbalance and a high SBP during periods of system stress.

1.3.6 Other Demand Control Offer Price Options

The PSMG also considered some other options for the Demand Control Offer Price, which if pursued, would have formed an Alternative Modification.

There was a suggestion that the Market Index Price could be used as the Demand Control Offer Price as it would be a more appropriate reflection of the costs incurred by Suppliers due to the Demand Control and would therefore act as compensation for the Demand Control. Another option was use of the statutory Value of Lost Load (VoLL). The arguments for VoLL were that this was a surrogate for the price at which customers, in the absence of any explicit desire to reduce demand, would not wish to purchase electricity. Furthermore, this would be a fixed administrative price and would simplify the Modification Proposal. It was recognised that this simplification would apply to any fixed price that might be applied. A value of zero was also suggested as a fixed price so that the volume of the Demand Control is entered into the Bid-Offer stack as a system balancing action (i.e. at the top of the stack). This would appropriately treat the change in a Supplier's Metered Volume due to the Demand Control, because Parties imbalance position with or without the Demand Control would stay similar. However it would not reward Suppliers for what could be regarded as a market failure. A further option suggested was the Demand Control Offer Price from the marginal Offer, but capping it at VoLL, however, since this introduced more complexity, the PSMG did not pursue this option further.

The PSMG could not reach a consensus on any of the above options for the definition of the Demand Control Offer Price. Therefore no Alternative Modification was developed.

1.3.7 Volume

The volume of the Demand Control needs to be estimated. The PSMG considered that a simple estimate for the total volume lost from the system due to the Demand Control (Total Demand Control Volume) which could be derived from the information exchange already allowed for in the Grid Code between the SO and the relevant LDSOs would suffice as a reasonable approximation of lost demand. This overall volume would then need to be allocated to the relevant Supplier BM Units in the affected GSP Group(s). This would be calculated using latest firm available BM Unit Metered Volumes (from the Settlement Final (SF) run) to establish the proportion of demand of each BM Unit in the GSP Group affected. However, the PSMG did note that the volume estimation would not reflect reality and the SVA mechanisms would not necessarily allocate demand reductions accurately.

Also as the volumes are to be treated as Offer Acceptance equivalents, then the Non-Delivery Rule would need to be relaxed for these acceptances to mitigate the effect of the Non-Delivery Rules. If workaround 18 were to be employed to enter the deemed Demand Control Offers into the Bid-Offer stack, it would also be necessary to create, or modify, Physical Notifications (PNs) and Bid-Offer Data to enable the deemed offer and associated deemed acceptance to be established.

1.3.8 Reporting

In the first instance, the PSMG considered that there should be prompt reporting of the Demand Control Volumes attributed to relevant BM Units and the Demand control Offer Price. Given the difficulty of identifying the prices and volumes for each BM Unit and also that the PSMG had requested that minimal system changes should be required to implement P138, the PSMG acknowledged that accurate and comprehensive prompt reporting could not be achieved. Instead the PSMG concluded that it would be useful to promptly report (i.e. on the Balancing Mechanism Reporting Service (BMRS)) an estimate of the total Demand Control Volume for each Demand Control Settlement Period, the likely Demand Control Offer Price, derived from the highest priced offer which is greater than 1 MWh in energy and that would not be tagged out by the CADL, taken or utilised in the Settlement Period within which Demand Control was invoked and the affected GSP Group(s). The proposal also recognises that the Demand Control instructions for the start and end of the Demand Control Period would be reported on the BMRS. A manual report would be issued detailing the Demand Control Offers attributed to relevant BM Units alongside the Settlement Report, by the SAA.

1.3.9 Implementation Approach

The PSMG considered that there should be minimal system impact from this proposal and that ad-hoc calculations and estimates would suffice. Therefore the solution to P138 involves a manual workaround.

1.3.10 Whether the Modification Proposal fall within the vires of the Code

The PSMG considered whether P138 falls within the vires of the Code with reference to the Authority decision letters on P59 'The Acceptance of Bids and Offers to Honour a BM Unit's Dynamic Parameters Beyond the Balancing Mechanism Window', P80 'Deemed Bid/Offer Acceptances for Transmission System Faults' and P87 'Removal of Market Risk Associated with the Operation of a Generator Inter-Trip Scheme'. The PSMG expressed the view that the reason that the Authority did not implement these Modifications was for reasons of efficiency rather than on the grounds that they were ultra-vires. For example, P80 and P87 involved issues of compensation that were being discussed as part of the Connection and use of System Code (CUSC) amendment entitled CAP048 and P59 was rejected since it was covered by another industry document. Although the Grid Code contains obligations relating to Demand Control, it does not cover related commercial provisions. The CUSC does not mention Demand Control and thus is not a suitable place for contingency measures relating to Demand Control. The Code does however mention Demand Control and is a commercial document hence it was deemed by the PSMG to be the most suitable place for contingency measures relating to certain aspects of Demand Control. One member of the PSMG commented that P138 seeking compensation seemed to be similar to P80 and P87 and hence perhaps would be rejected by the Authority for similar reasons. However the other members of the PSMG disagreed. P80 and P87 were concerned with transmission access whereas P138 is not a network problem but an energy problem – i.e. there is not enough energy to meet demand.

The PSMG also noted that as each Settlement Period was considered individually, there was no element of going beyond the Balancing Mechanism Window Period. Hence, the Modification Proposal was believed to be a legitimate one to be considered under the auspices of the Code.

1.3.11 Definition of Marginal Price

Aside from the definition of marginal price for the Demand Control Offer Volume agreed by the PSMG, the PSMG also considered two other definitions of marginal price.

- The highest priced Offer (following NIV tagging) from the Settlement Period preceding the Demand Control could be used to set the Demand Control Offer Price. It is assumed that Demand Control will only occur during a period of peak demand and so the preceding period will closely approximate the Settlement Period in which the Demand Control occurred. Therefore the assumption is that the only difference between the two Settlement Periods is the Demand Control. Effectively, two calculations would therefore be carried out in the Settlement period prior to the period of Demand Control – the SBP would be calculated as normal for that Settlement Period and the Demand Control Offer Price would also be calculated as the last energy Offer in the NIV in that Settlement Period. The PSMG believed that the option actually chosen for the Demand Control Offer Price, defined in section 1.2, would set a more accurate price as it would be set at the same price as the last Accepted Offer before Demand Control occurred. Also it would be more realistic as it was an Offer Accepted in the same Settlement Period in which Demand Control was invoked.
- From the Period in which Demand Control was invoked, the highest priced Offer left after NIV tagging would set the Demand Control Offer Price. The calculation would be more complex as two calculations would have to be carried out for the Settlement Period within which Demand Control occurred to obtain the imbalance prices, which could not be carried out simultaneously. Firstly, all taken Bids and Offers would be stacked (without the deemed Demand Control Volume) and all the tagging would occur as usual. The highest Offer left in the Bid-Offer Stack after NIV tagging has occurred would be taken as the Demand Control Offer Price. The Bids and Offers would then be re-stacked, this time including the deemed Demand Control Volume, priced at the Demand Control Offer Price NIV Tagging would then occur and the SBP would be calculated as per normal.

The PSMG believed that there might however be problems with this mechanism. Following the Demand Control, the SO may have to take bids to ensure that the level of generation meets demand and to bring some generators off to increase the margin. This could potentially make the market long, which will affect the calculation of the Demand Control Offer Price. The PSMG therefore discounted this option for the definition of the Demand Control Offer Price.

1.3.12 Impact on the Grid Code

The P138 Modification Proposal noted that there might be a requirement to amend OC6 and / or OC7 of the Grid Code. If P138 were approved, the SO could raise any consequential Grid Code changes prior to implementation.

1.3.13 Impact on Manifest Errors

The PSMG agreed that since the proposed solution established Demand Control Offer Volumes according to rules set out in the Code, any errors would be rectifiable under the current disputes process. If the total Demand Control Offer Volume provided by the SO to the SAA at Settlement Day + 2 (Business Days) was considered to be manifestly wrong, this could be resubmitted by the SO, up to 48 hours after the end of the Demand Control Period. There would be no need to use or amend the Manifest Error process in this case.

1.3.14 Interaction with other Modifications

The PSMG have identified the following other Modification Proposals that could potentially interact with P138:

<u>P59 'The Acceptance of Bids and Offers to Honour a BM Unit's Dynamic Parameters Beyond the Balancing Mechanism Window', 'P80 'Deemed Bid/Offer Acceptances for Transmission System Faults' and P87 'Removal of Market Risk Associated with the Operation of a Generator Inter-Trip Scheme'</u>

The interaction between P138 and P59, P80 and P87 is discussed in section 1.3.10 above.

<u>P71 'Transfer of Imbalances caused by Balancing Services to the Transmission Company Energy Account'</u>

P71 introduced the concept of an Applicable Balancing Service (QAS). This is where the SO determines a volume associated with the provision of Applicable Balancing Services for a BM Unit and Settlement Period. These volumes are then removed from the Energy Account of the lead Party of the BM Unit delivering the balancing service and (implicitly) transferred to the Energy Account of the SO, thus removing the lead Party of the BM Unit delivering the balancing service from exposure to the consequences of Imbalance on the volumes deemed to have been delivered for balancing services provision. This method will not be used for P138 since, to introduce a new variable similar to QAS would involve a system change, which the PSMG were not keen to do. The QAS variable may however be manually adjusted as a workaround for the manual solution for P138 to allow the Energy Account of the lead Party of each Impacted BM Unit to be adjusted to reflect the Demand Control Offer Volume.

<u>P135 'Marginal System Buy Price During Periods of Demand Reduction'</u>

The PSMG noted that the Authority's determination letter in respect of P135 stated that the Authority was concerned that the current rules during periods of Demand Control might not offer appropriate commercial incentives to balance in such situations. P138 seeks to address this issue.

P136 'Marginal Definition of the 'Main Energy Imbalance Price' and P137 'Revised Calculation of System Buy Price and System Sell Price'

The PSMG agreed that there is no interaction between P138 and P136 and P137

P144 'Removal of CADL from the BSC'

The Demand Control Offer Price calculated as a marginal price for P138 requires that the Offer setting the marginal price would be not be an Offer that would be CADL tagged (or De-Minimis tagged). Should P144 be approved, the calculation of the Demand Control Offer Price at a marginal price would be amended so that the marginal price would be calculated from all Offers, except those that would be De-Minimis tagged.

1.3.15 Interaction with Existing Code Arrangements for Demand Control Instructions

There are already arrangements in Grid Code BC2.9 and the Code Q5 to treat certain Demand Control instructions as Bid Offer Acceptances. These provisions apply only to Demand Control instructions issued in relation to a particular BM Unit (and not to Demand Control instructions issued to an LDSO, which affect all Supplier BM Units in the affected GSP Group). These provisions would not be amended under P138.

1.3.16 Interaction with Fuel Security Periods

There is no interaction between P138 and fuel Security Periods as there are separate provisions for fuel Security Periods, at which point it is the responsibility of the Secretary of State to turn off the normal Balancing Mechanism, if required. If a fuel Security Period were instructed, this would constitute an end to the Demand Control Period as defined under P138.

1.3.17 Justification for P138

The PSMG discussed the justification for P138. Since the PSMG had concluded that P138 was within the vires of the Code, and a number of the PSMG believed that Demand Control measures should be included within the Code, the PSMG believed that a mechanism for the inclusion of Demand Control within the Code should be developed.

1.4 Assessment of how the Proposed Modification will Better Facilitate the Applicable BSC Objectives

1.4.1 Applicable BSC Objective 3(b) The efficient, economic and co-ordinated operation by the Transmission Company of the Transmission System

It was suggested that, by providing an explicit cost signal in relation to the cost of demand lost by Parties, to the SO, that the SO's behaviour would be optimised in respect of forward contracting and Balancing Mechanism actions. Hence, Objective (b) would be better achieved.

The counter argument was that the SO does not see Demand Control as a decision taken based upon an economic rationale but rather sees Demand Control as an action driven by operational requirements, taken as a last resort without consideration of the economic consequences. Some of the PSMG agreed that there is no incentive for the SO to initiate Demand Control and so P138 would not change the SO's behaviour. Furthermore, even if it was believed that the SO would respond to an economic incentive in relation to Demand Control, the infrequency with which it is used would have little impact on the SO's decision making. However, some members considered that the prospect of Demand Control was becoming more likely and as such the SO should be financially incentivised to avoid it.

Some members of the PSMG believed that P138 sends the correct signals to incentivise Parties not to be short as it would likely increase imbalance prices during periods of Demand Control. However, other members of the PSMG stated that the signals i.e. high imbalance prices during Demand Control Settlement Periods, come too late as, by the time Demand Control is invoked, Gate Closure has already passed for the following two Settlement Periods. As Demand Control is such a rare event, it was argued that neither the SO nor Suppliers will change their behaviour.

It was suggested that P138 established an enhanced incentive to balance, since the inclusion of the Demand Control Volume and price in the calculation of the SBP (when the market was potentially short) would mean that it would tend towards the marginal Demand Control Offer Price. A counter view was that, because Demand Control would attract this marginal offer price, this may encourage Suppliers to go short and precipitate Demand Control. The rationale for this scenario being that, although the SBP would tend towards the marginal Demand Control Offer Price, the actual marginal offer price would constitute a windfall gain for those subject to Demand Control. On this basis, an administered Demand Control Offer Price of £0/MWh would be an option. However, it was suggested that no Supplier could predict the outcome of Demand Control (which GSP Groups, or Suppliers within those GSP Groups, would be affected) and so such exploitation would not occur. Another counter argument was that Demand Control was considered to be such a rare event that no Supplier would adjust their contracting strategy to mitigate the impact of Demand Control.

1.4.2 Applicable BSC Objective 3(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;

It was suggested that, under the current Demand Control process there was a risk that a Supplier would not have the costs of forward contracting fully re-imbursed through the change in its imbalance position due to the Demand Control. Under the current baseline, Suppliers that are short and impacted by the Demand Control action, would become less short and therefore would face less exposure to SBP. It was also noted that SSP may be negative if reduced generation was required to compensate for any overshoot on Demand Control. Given that, ahead of the event, it would not be known how much Demand Control would be required, nor which GSP Groups and Suppliers within a GSP Group would be affected, this constituted a risk to a Supplier due to the differential costs faced by Parties. Counter arguments to this were that, under P138, there could be a windfall gain to Suppliers and that given the rarity of the event, there would not be a material impact on Supplier risk. It was also argued that BSUoS charges following Demand Control would increase under P138 as the cost of the demand lost by Suppliers for the Demand Control Offers would be recovered through BSUoS. Increased BSUoS charges would affect all Parties (Suppliers and generators), whilst only those Suppliers directly impacted by Demand Control would benefit from the payment at the Demand Control Offer Price. This would lead to parties not directly impacted by the Demand Control action effectively subsidising the payment to Suppliers whose Metered Volumes were affected.

1.4.3 Applicable BSC Objective 3(d) Promoting efficiency in the implementation and administration of the balancing and settlement arrangements

The PSMG recognised that the Modification Proposal would constitute an increase in the cost and complexity of the central systems. A minority of members suggested that the cost to implement P138 would outweigh the benefits of P138, regardless of the degree of cost and complexity, by virtue of Demand Control being such a rare and unpredictable event.

1.5 Governance and Regulatory Framework Assessment

The starting point for P138 is an instruction issued by the SO to LDSOs in accordance with the Grid Code. The Grid Code contains reporting details (System Warning messages) for NISM, HRDR and DRI, but does not containing reporting details if Demand Control occurs. The PSMG believe that since this obligation is to be included in the Code, there is no need to also include it in the Grid Code, however the SO believes that there may potentially be an impact on the Grid Code and is currently reviewing relevant documentation.

2 RATIONALE FOR MODIFICATION GROUP'S RECOMMENDATIONS TO THE PANEL

2.1 Summary of the Recommendations and Rationale

Section 1.4 sets out the PSMG views in respect of P138 and the Applicable BSC Objectives. The PSMG considered the consultation responses and noted that they were evenly split on whether P138 did or did not better achieve the Applicable BSC Objectives.

- Members that believed that P138 did better facilitate the achievement of the Applicable BSC Objectives believed that Objective (b) and, to a lesser extent Objective (c) were better achieved and that this outweighed the impact on Objective (d);
- Some members that believed that P138 did not better facilitate the achievement of the Applicable BSC Objectives believed that Objectives (b) and (c) were better achieved, in principle, but that the rarity of a Demand Control event was such that, regardless of the degree to which cost and complexity were increased, the deleterious impact on Objective (d) would outweigh the benefits (if any); and
- Other members that believed that P138 did not better facilitate the achievement of the Applicable BSC Objectives considered that, Objective (d) notwithstanding, there was no better facilitation of Objectives (b) and (c), in any event.

Following the PSMG's discussion of the consultation responses (Section 6.2), a number of the PSMG believed that overall, P138 better facilitated the Applicable BSC Objectives, however a similar number of the PSMG believed that P138 would not better facilitate the Applicable BSC Objectives (also reflected in the balance of responses received to the consultation).

The PSMG did therefore not reach a recommendation in respect of P138 and have asked the Panel to determine whether P138 better facilitates the Applicable BSC Objectives.

The PSMG recommends a provisional Implementation Date for P138 of 3 November 2004 if an Authority determination is received on or before the 30 April 2003 or 23 February 2005 if an Authority determination is received on or before the 20 August 2003. These dates take into account the lead time and project duration times for the implementation of P138 in a BSC Systems release. Since a manual and low cost solution to P138 is required, it is more cost effective and efficient to implement P138 in a BSC systems release.

3 IMPACT ON BSC SYSTEMS AND PARTIES

An assessment has been undertaken in respect of BSC Systems and the following have been identified as potentially being impacted by the Proposed Modification.

3.1 Overview

The PSMG have recommended a manual solution for P138. In summary, development and implementation of P138 will incur BSC Central Service Agent costs of approximately **£17,660** (Option I, LogicaCMG Impact Assessment, Annex 6). Furthermore, each time Demand Control is invoked, costs of approximately **£1,537** per Settlement Period affected (and based on 100 BM Units being affected) will be incurred. There is an **additional 15% tolerance** associated with these figures.

This excludes ELEXON effort of approximately **80 man days** and additional ELEXON costs of

- £2,000 (Approximately 10% of the development cost for the BSC Auditor effort); and
- £1,000 (Approximately 5% of the development cost for any clarification in the solution during development).

The total cost for the Implementation of P138 is therefore **£20,600** plus **80 ELEXON man Days** plus **£1,537 per Settlement Period** which is affected by demand Control (based on 100 BM Units being affected).

There is also an **additional 20% tolerance** associated with these figures.

A lead time of approximately 22 weeks is required.

Therefore, provisional discussions indicate that if:

- P138 is to be delivered in the **November 2004** (3 November 2004 Implementation Date) BSC Systems release, an Authority determination is received by **30 April 2003**; and
- P138 is to be delivered in the **February 2005** (23 February 2005 Implementation Date) BSC Systems release, an Authority determination is received by **20 August 2003**.

3.2 BSCCo

BSCCo is impacted by the requirement to implement P138. Furthermore, should Demand Control occur, BSCCo will receive notification of the Demand Control in order that industry queries can be addressed if required.

The Impact Assessments are provided in Annex 7, however, in summary:

- The ELEXON CVA Programme estimate a resource requirement of **41 man days** for the development and implementation of P138, plus **20 man days** for release overheads.
- ELEXON CVA Operations estimate a resource requirement of **5 man days** for the development and implementation of P138
- ELEXON Assurance estimate a resource requirement of **6.5 man days** for the development and implementation and provision of assurance to the CVA programme for the implementation of P138.
- ELEXON Governance and Regulatory Affairs believe that there may be an impact on the department as there could be an increase in the workload of the Panel, who oversee most of the section G 'Contingencies' provisions.

- The ELEXON communications department have indicated that there may be a resource requirement of **6 ELEXON man days** if the Pricing Data section of the BSCCo website is to be modified.
- The following ELEXON departments have indicated that there is **no impact** from the implementation of P138: Market Monitoring, Strategic Commercial Services and Finance.

Therefore a total of approximately **80 ELEXON man days** are required for the development and implementation of P138. There is also an **additional 20% tolerance** associated with this figure.

There are also additional ELEXON costs of **£3,000** associated with the development and implementation of P138 consisting of:

- £2,000 (Approximately 10% of the development cost for the BSC Auditor effort); and
- £1,000 (Approximately 5% of the development cost for any clarification in the solution during development).

There are no additional ELEXON demand led costs associated with P138.

There is also an **additional 20% tolerance** associated with these figures.

3.3 BSC Systems

The Detailed Level Impact Assessment for P138 is provided in Annex 6 in full and is summarised in this section.

The following table details the impacts on the BSC Systems from the implementation of P138.

System / Process	Potential Impact of Proposed Modification
Registration	No Impact
Contract Notification	No Impact
Credit Checking Systems	No Impact
Balancing Mechanism Activities	Impacted as the Demand Control will be considered to be equivalent to an Offer Acceptance.
Collection and Aggregation of Metered Data	No Impact
Supplier Volume Allocation	No Impact
Settlement	Impacted as the Demand Control Offer Volumes for each BM Unit will be fed manually into the calculation of SBP, the calculation of Energy Imbalance for each Energy Account and the calculation for credit cover so that the position of each Party in these areas is similar to what it would have been had the Demand Control not occurred. Also the Demand Control Offer Volumes would be payable by the SO and so included in CSOBM and the BM Units excluded from Non Delivery Rules so that they would not apply for these Acceptances.
Clearing, Invoicing and Payment	No Impact

System / Process	Potential Impact of Proposed Modification
Reporting	Impacted. The initial estimations of Demand Control would be published on the BMRS. Also the Settlement Report would contain details of the Total Demand Control Volume, however, an additional report would have to be sent manually to explain why the Settlement Report contained the Total Demand Control Volume and give details of each Supplier's deemed Demand Control Offers

The BSC Central Service Agent provided a Detailed Level Impact Assessment which provided costs and timescales for a number of options that the PSMG were considering at the time of obtaining the impact assessment. Furthermore, the BSC Central Service Agent included a semi automated solution based on the method developed by the PSMG, an alternate solution covering all the requirements detailed by the PSMG and a fully automated solution. The PSMG agreed that the solution to P138 should not involve any system changes and so the details of the fully automated solution are not included in this section.

The permutations of solutions available mean that there are twenty-four options available for the solution, however the majority of the solutions include four different calculations of the Demand Control Offer Price to take into account possible alternate modifications. Details of the permutations are included on the BSC Agent Impact Assessment in Annex 6. Furthermore, half of these options involved BSCCo carrying out some of the processing. The PSMG have agreed that since the costs of BSCCo carrying out some of the processing compared to SAA are small, all processing should be carried out by SAA.

The BSC Agent Impact Assessment highlighted the problem that if a BM Unit already had an acceptance against it, then it would be hard to manually attribute that Demand Control Offer to it as an acceptance number would need to be generated as the Demand Control Offer acceptance would not have an acceptance number automatically generated. Another problem highlighted by the BSC Agent Impact Assessment was that as the solution specified required a change to the PN of the BM Unit, the accepted Offer on that BM Unit would also have to be amended. The PSMG therefore agreed that the LogicaCMG alternate solution would be the best way to implement P138 as it resolves these issues. (LogicaCMG Impact Assessment Form Reference I, Option 1). This project has a 6 week duration.

Therefore, the development and implementation of P138 will incur costs of **£17,600** for Central Service Agent development. No BSC Agent Project overhead has been quoted for P138 since P138 would be implemented as part of a BSC systems release as this is more cost effective and efficient. The operation of P138 will incur costs of **£1,537** per Settlement Period affected by the Demand Control (Based on 100 BM Units). There is also an **additional 15% tolerance** associated with these figures.

The changes will require a BSC Central Service Agent development time of **6 weeks**.

3.4 Parties and Party Agents

P138 may impact BSC Parties due to the change to the calculation of the Energy Imbalance Price during Period of Demand Control. If BSC Parties verify trading charges, then there will be an impact on any such processes / systems for such verification. Also Parties will be impacted by receiving the additional manual report alongside the Settlement Report for periods of Demand Control detailing the extent to which Parties were affected by the Demand Control.

4 SUMMARY OF TRANSMISSION COMPANY ANALYSIS

The Transmission Company Analysis (provided in full in Annex 5) states that no impact has been identified resulting from P138 to the SO's ability to discharge its actions under the Transmission Licence. Also minimal costs have been identified for the changes required to SO documented procedures from P138.

It should be noted that the SO has stated in its consultation response that at the start of the Demand Control Period, the SO will only be able to provide the start time of the Demand Control and the details of the LDSO that has been asked to initiate Demand Control. It will not be able to provide the GSP Group affected nor the volume of Demand Control requested. The SO also notes that it may be difficult to estimate the volume of Demand Control until some time after the end of the Demand Control Period. The PSMG agreed that the initial notifications of the Demand Control Provided by the SO to the BMRA would contain the information that the SO can provide at that time. This has been reflected in the P138 mechanism in section 1.2.2.

5 IMPACT ON CODE AND DOCUMENTATION

In summary, the following documents are impacted by the implementation of P138:

- The Code, Sections G, Q, T and X, Annex X-1;
- BSCP515 Licensed Distribution;
- The SAA Service Description;
- The BMRA Service Description;
- The SAA User Requirements Specification (and Operating Service Manual and Local Working Instructions);
- The ELEXON Business Process Model; and
- The ELEXON Obligations Register.

5.1 Balancing and Settlement Code

Draft Legal Text for Proposed Modification P138 is provided in Annex 1 . The Legal Text will be finalised prior to the consultation in the Report Phase.

The following table sets out a summary of the amendments to the Code required to give effect to P138:

Code Section	Potential Impact of Proposed Modification
G 'Contingencies'	There will need to be a new subsection in section G describing the following: The need for the SO to submit Total Demand Control Volumes for each Demand Control Settlement Period for each GSP Group when a Demand Control Period is initiated. This clause will also need to define a Demand Control Period and the notifications the SO would need to make to initiate and terminate such a Period. The obligation on BSCCo to provide the LDSO – GSP Group

Code Section	Potential Impact of Proposed Modification
	relationships to SAA. To identify that deemed acceptances will arise from OC6 Demand Control instructions. The obligation on the SAA to calculate the Demand Control Acceptance volumes and the Demand Control Offer prices. The description of how the calculations for the Demand Control Offer Price and the Demand Control Acceptance Volume should be derived. To state that the Demand Control Offers would be treated like other accepted offers, for the purposes of establishing SBP. To relax the obligation on the SO for reporting Demand Control acceptances etc within 15 minutes. To reflect the additional liability of the SO to pay for the Demand Control Offers
T 'Settlement and trading Changes'	Section T will need to be amended to reflect the non-application of Non-Delivery Rules.
X Annex X1 'General Glossary'	Various Terms such as Demand Control Period, Demand Control Settlement Period and Total Demand Control Volume will need to be defined.

5.2 Code Subsidiary Documents

The following table sets out the amendments to Code Subsidiary Documents required to give effect to P138:

Code Subsidiary Document	Potential Impact of Proposed Modification
BSCP515 Licensed Distribution	BSCP515 requires amendment to give the process by which BSCCo will notify SAA of any new LDSO – GSP Group relationships.
The SAA Service Description	The SAA Service Description requires amendment to detail the extra processing to be carried out by SAA during Periods of Demand Control.
The BMRA Service Description	The BMRA Service Description may require amendment to detail the extra reporting on BMRA (although it should be noted that this reporting will be on the System Warning Message Screen which is a free text field so there is no requirement to amend the BMRA system).

5.3 Other ELEXON Configurable Items

The following table sets out the amendments to other ELEXON Configurable Items required to give effect to P138:

ELEXON Configurable Item	Potential Impact of Proposed Modification
The SAA User Requirements Specification (and Operating Service Manual and Local Working Instructions)	The SAA system and process documentation requires amendment to detail the extra processing to be carried out by SAA during Periods of Demand Control.
The ELEXON Business Process Model	The Elexon Business Process Model requires amendments to reflect the new requirements during Demand Control Settlement Periods.
The ELEXON Obligations Register	The Elexon Obligations Register requires amendments to reflect the new requirements during Demand Control Settlement Periods.

5.4 Impact on Core Industry Documents and Supporting Arrangements

The following table sets out the amendments to Core Industry Documents required to give effect to P138:

Document	Potential Impact of Proposed Modification
Grid Code	The SO highlighted that there may be an impact on the Grid Code, in particular OC7 (Reference 3) to ensure that the Grid Code is consistent with P138. The SO is currently reviewing the Grid Code in this area and noted that if changes are required to the Grid Code, this may impact the Implementation Date of P138.

6 SUMMARY OF CONSULTATIONS

Consultation question	Respondent agrees	Respondent disagrees	Opinion unexpressed
1. Do you believe Proposed Modification P138 better facilitates the achievement of Applicable BSC Objective (b) The efficient, economic and co-ordinated operation by the Transmission Company of the Transmission System?	2	4	1
2. Do you believe Proposed Modification P138 better facilitates the achievement of Applicable BSC Objective (c) Promoting effective competition in the generation and supply of electricity, and (so far as consistent therewith) promoting such competition in the sale and purchase of electricity?	3	3	1

3. Do you believe Proposed Modification P138 has a negative impact on Applicable BSC Objective (d) Promoting efficiency in the implementation and administration of the balancing and settlement arrangements	4	2	1
4. Overall, do you believe Proposed Modification P138 better facilitates the achievement of the Applicable BSC Objectives?	3	3	1
5. Do you support the implementation approach described in the consultation document / the implementation option preferred by the Modification Group?	4	1	1
6. Do you believe there are any alternative solutions that would better facilitate the Applicable BSC Objectives to a greater degree than P138 (for example, adopting P138 with one of the suggested alternative pricing options or any other options that the Modification Group has not identified) that should be considered?	1	4	2
7. Do you agree with the PSMG's views of the scope of P138 in relation to those Parties covered / not covered by the modification (see page 3 of the consultation document)?	5	0	2
8. Does P138 raise any issues that you believe have not been identified so far and that should be progressed as part of the Assessment Procedure?	1	4	2

6.1 Modification Group's Summary of the Consultation Responses

1. Do you believe Proposed Modification P138 better facilitates the achievement of Applicable BSC Objective (b) The efficient, economic and co-ordinated operation by the Transmission Company of the Transmission System?

Arguments For:

P138 will ensure that Demand Control periods can be effectively utilised under the BSC.

P138 will introduce appropriate incentives on NGC to ensure that the cost of Demand Control is appropriately targeted.

Demand Control is an instruction issued to meet energy requirements, and therefore Suppliers should be paid for demand shed under OC6. Demand Control is a rare event and often a last resort decision, however introducing a price for Demand Control similar to other Balancing Mechanism actions will lead to the efficient and economic running of the Transmission System by the Transmission Company.

Arguments Against:

P138 will have a negligible impact on the behaviour of the SO in maintaining an economic, efficient and co-ordinated Transmission System.

Demand Control is (and should remain) a purely operationally driven decision taken by the SO to ensure the overall system stability where there is either insufficient contracted reserve or failure of the market to provide sufficient energy to meet demand and implemented via Emergency Instructions. It is not a commercial decision taken by the SO (such commercial decisions being taken by the SO via the other means such as the BM, Pre Gate Closure BM Unit Transactions (PGBTs)). The level of contracted reserve is driven by the SO's obligations in relation to Security of Supply. Putting a price on Demand Control, as suggested under P138, will not impact the level of reserve held and will do nothing to prevent insufficient generation being contracted by Suppliers and the market failing. It will, as a result, fail to lead to the more efficient, economic or co-ordinated operation of the Transmission System. The SO should not be penalised following the failure of the market over which it has limited control.

In the very rare event that Demand Control is used it should only be utilised to ensure the overall stability of the system. In this respect the SO should only consider the technical aspect of maintaining the integrity of the system and should not take account of any financial consideration.

If Demand Control was an option available to the SO as a balancing service that could be utilised based upon economic rationale, then it would be right and proper that Demand Control were priced and in doing so, Applicable BSC Objective (b) would be better facilitated. However, Demand Control as instructed under OC6 of the Grid Code is NOT an option open to the SO based upon economic rationale. If it were, the SO would have made use of it as a justifiable balancing service long before now. The very fact that the SO has not instructed Demand Control for such a long time clearly indicates that it is not seen as a 'free' option and is treated as an action to be 'avoided at all costs'. Charging the SO for taking Demand Control will have no impact upon its behaviour. Demand Control will occur whether or not there is a cost associated with it. The SO would take every feasible action, irrespective of price, prior to initiating Demand Control.

If the assertion that the SO will respond to the pricing of Demand Control is correct then there could be a perverse incentive making it more likely that Demand Control is initiated. P138 proposes that the SO pays for Demand Control at the marginal price. The Marginal Price is defined as the highest priced offer taken prior to the initiation of Demand Control. This could incentivise the SO to take Demand Control earlier than would otherwise have been the case, as the earlier it is initiated, the cheaper it will be. If this incentive is taken to its logical conclusion, Demand Control will be the first action taken by the SO as it will be 'free' due to the fact that there is no Offer price to set the cost of the action. Based upon this logic P138 fails to achieve its objective of making Demand Control less likely.

Based upon the same incorrect premise that the SO will respond to the costing of Demand Control, it could be argued that the SO would never take Demand Control, preferring to wait until the system begins to collapse in an uncontrolled manner and a Black Start situation occurs. This would avoid the need for the SO to pay for the action at the prevailing marginal price as proposed by P138, but would obviously be an undesirable outcome for the wider industry and an inappropriate incentive for the SO.

Price Signals

Even though treating the amount of demand reduction as an offer appears to be the correct intellectual thing to do, it is not clear that it will send a sufficient signal to participants to improve balancing or to ensure sufficient plant is available. The signal will be sent too late, as it comes once the event has actually occurred. It is possible for imbalance prices to send signals to participants when past imbalance prices alter expectations of likely future levels. However, this mechanism will be used infrequently meaning that participants will have insufficient experience of the relevant prices for it to alter their future expectations. Market participants have previously indicated that pricing signals that only present themselves at times of Demand Control come too late to affect behaviour as they are only seen after the event and can not be predicted. As such, higher imbalance prices that only occur following Demand Control will have no impact upon the contracting behaviour of industry participants.

Sharpened incentive to balance through increased imbalance prices

The inclusion of deemed Demand Control Offers (at a marginal offer price) within the offer stack used to calculate imbalance prices (SBP / SSP), could lead to an increase in average SBP and thus supposedly increase the incentive on parties to balance. Whilst it is desirable for the SBP to be increased at times of system stress to improve the incentives on Parties to balance, it is believed that there are more appropriate means of achieving this. Imbalance prices are only increased under P138 as a result of the SO paying Suppliers what is effectively a windfall payment following Demand Control. This windfall payment may reduce incentives on Suppliers to balance as it would reduce or negate any increase in imbalance cost exposure faced by Suppliers who are in a short contracted position. Without the perversions associated with windfall payments, the sharper incentives on parties' to balance would better facilitate Applicable BSC Objective (b). Unfortunately, the increase in imbalance prices is directly linked to the payment of such windfall gains.

System Operator Payment following an action that could have been avoided by the market more efficiently

Payment at a marginal price, by the SO, for the Demand Control Volume is in direct contradiction to Applicable BSC Objective (b) as it would almost certainly have been more efficient for the energy to be procured through forward contracts to ensure that sufficient was made available. If Demand Control is required due to a lack of available energy to meet demand, the market should be incentivised to contract for greater volumes. It can readily be assumed that the cost per MWh of such contracting would be less than the marginal offer price P138 suggests is paid for every MWh of demand reduced.

Previous industry views relating to sharper imbalance prices at times of Demand Control

It appears obvious that the P138 proposal would lead to increased uncertainty in relation to imbalance prices and RCRC payments at times of Demand Control. Under the proposal, the increase in imbalance prices, and resultant RCRC payments, would be dependent upon the volume associated with, and price at which, Demand Control is instructed. Neither the volume nor price, associated with the Demand Control action under P138, is predictable. As such, P138 will lead to increased uncertainty within the market.

The proposed P138 mechanism relies upon post event calculation and allocation of volumes, identification of prices and calculation of payments. This means that prompt pricing becomes impossible during a Demand Control Period, a requirement that has previously been held as sacrosanct by market participants during other pricing modification discussions.

It could be suggested that P138 results in the need for the development of a separate pricing regime that only operates at times of Demand Control. As industry participants have previously argued, this could be seen to be inefficient and to inappropriately introduce unnecessary complexity and uncertainty into the market.

2. Do you believe Proposed Modification P138 better facilitates the achievement of Applicable BSC Objective (c) Promoting effective competition in the generation and supply of electricity, and (so far as consistent therewith) promoting such competition in the sale and purchase of electricity?

Arguments For:

By treating Demand Control as a BM action and removing the potential financial risks associated with Demand Control measures, the Modification Proposal will better facilitate Objective (c). P138 will remove the risk that parties are exposed to high and unpredictable imbalance charges and RCRC during a Demand Control Period.

P138 will better facilitate effective competition in the sale and generation of electricity. There is a defect within the current methodology, which may benefit the party that caused the problem to the detriment of a party that attempted to balance their position. P138 will amend this to ensure all Parties contract positions are reflective of their notified position prior to Demand Control being initiated.

P138 will remove the ability of the SO to call Demand Control and not pay for the instruction.

Any solution should ensure that the volume associated with the Demand Control instruction is feed back into the derivation of the imbalance price. This will ensure that the NIV tagging process is more robust as it will be more accurate and it will also ensure that the energy imbalance price is more reflective of the actions taken by the SO.

Importing Supplier BM Units in a GSP Group affected by Demand Control should not be exposed to increased imbalance exposure because of such an instruction. P138 would promote competition by removing this exposure.

Under current arrangements, Suppliers' incentives to balance are dampened at times of Demand Control as the resultant reduction in Metered Volumes will generally improve affected Suppliers' imbalance positions. By treating Demand Control Volumes as deemed offers, Suppliers' contracted positions are changed such that their imbalance positions are not impacted by the Demand Control action. The removal of the current perversion that could reduce incentives on Suppliers to balance at times of Demand Control does better facilitate Applicable BSC Objective (c).

Arguments Against:

It is not clear that the present treatment of Demand Control is acting as a deterrent to competition in supply.

Treatment of volume associated with Demand Control

It is not clear that Parties that are short would be the ones that caused the Demand Control in all circumstances. It may be that there is a shortfall in area A, but due to system constraints the SO chooses to invoke Demand Control in area B and that Party X is short in area C. Given the system set up, it could be that Party X has not caused Demand Control to be invoked in area B, so should not be exposed to a higher SBP.

Also, it is not clear that the market has failed as the Demand Control could, for example, be invoked due to system problems. This is not a failure of the market, as there is no market for the system itself as there is only one SO.

In most cases P138 will appropriately account for the impact of Demand Control on Suppliers' contracted volumes. However, this may not be the case where Demand Control is affected by disconnecting specific loads. In such a situation it will be quite clear which Supplier's Metered Volume will have been affected and which Supplier should receive the Demand Control Offer payment. However, the proposed P138 mechanism does not take account of this, effectively smearing the reduced volume across the whole Supplier community based upon their market shares within the GSP Group. This results in Demand Control Offer payments being made to Suppliers that were not affected by the Demand Control action, whilst the Supplier that lost significant Metered Volume will only receive a small element of the total Demand Control Offer payment that should have been received under the principles of P138.

Despite the acceptance that, in most cases, P138 appropriately accounts for the impact of Demand Control on Suppliers' contracted volumes. Other elements of P138 counteract the benefits of correctly accounting for the volumes associated with Demand Control resulting in an overall detrimental impact on Applicable BSC Objective (c).

Windfall Payments to Suppliers at times of Demand Control

It is inappropriate for Suppliers to be rewarded with, what equates to, a 'windfall' payment in the event of Demand Control. The choice of which GSP to be subject to Demand Control is by the SO, without any involvement of Suppliers who thus take no action. If payment is made at the Marginal Offer Price taken within the BM, this could provide perverse incentives on Suppliers as they will benefit when there is Demand Control. It is appropriate that Suppliers are held neutral; i.e. do not incur costs where Demand Control is invoked for something they are not responsible for (being out of balance in a Demand Control area due to the action taken by the SO); but Suppliers should not receive a windfall profit. The issue of rewarding a Supplier for doing nothing is compounded when it is noted that the volume estimation would not reflect reality and would not necessarily allocate demand reductions accurately, which is turn is exacerbated by the proposition that the volume allocation rules should be based on an equivalent day methodology.

Increased costs for all parties through BSUoS charges

Payment for deemed offers associated with Demand Control will be re-charged to the industry through BSUoS. BSUoS charges reflect the costs incurred by the SO in balancing the system. The re-allocation of P138 costs through BSUoS charges results in Parties not impacted by Demand Control paying for the windfall payments received by Parties that are affected by Demand Control. Payment for Demand Control through BSUoS is based upon the total Metered Volumes of all Market Participants and has no relation to whether a party has contributed to the Demand Control initiation through their imbalance position. It is not appropriate for a Supplier to benefit from Demand Control, at the expense of other parties within the industry, when it could have been in a short position and thus contributing to the need for Demand Control to be initiated.

The allocation of BSUoS charges is based upon Metered Volumes. As such those Suppliers benefiting from windfall payments as a result of having their Metered Volumes reduced, will also benefit from reduced BSUoS, reduced Transmission Network Use of System (TNUoS) and possibly reduced Distribution Use of System (DUoS) charges, as these are all calculated as a factor of Metered Volume that will reduce following Demand Control. The recovery of total costs by the SO is achieved through the general socialisation of costs across the community. Whilst affected Suppliers benefit through reduced Metered Volumes, non-affected parties will face higher costs as their market share is artificially increased, seeing them incur a higher proportion of charges.

Barrier to entry for Smaller Suppliers

The impact of increased BSUoS charges being incurred by all industry participants whilst payment following Demand Control are made to a limited number of Suppliers based upon their Metered Volumes in a specific area, will discriminate against smaller Suppliers. Smaller Suppliers, or Suppliers whose customer base is location specific, are proportionately less likely to receive payment following Demand Control, but guaranteed to pay a proportional increase in BSUoS charges. This effect is in direct contradiction of Applicable BSC objective (c).

Re-allocation of monies around the industry

The eight examples, contained within Annex 8, demonstrate that the net impact upon industry participants resulting from cashflows associated with P138 is completely arbitrary. The range of different volumes, prices and imbalance positions that can be in place when Demand Control occurs means that no single party can be certain of being better or worse off. As a result, P138 is unlikely to change the behaviour of any participant. Demand Control will thus be just as likely to occur if P138 is approved as it is now. P138 provides no clear incentives that will change the behaviour of generators or Suppliers from that that they currently display. P138 will therefore have no impact upon the behaviour of the SO.

From the examples contained within Annex 8, it can quite clearly be seen that, whilst generators are generally made worse off by P138 as a result of facing higher BSUoS charges without benefiting from any windfall payments, there could be situations where they benefit as a result of the increase in RCRC payments being greater than the increased BSUoS charges.

Similarly, Suppliers not affected by Demand Control are generally worse off as a result of being subject to higher BSUoS costs without benefiting from payment for reduced volumes. However, these Suppliers too could be made better off under P138 if RCRC payments outweigh the increased BSUoS charges.

In all examples a Supplier is contributing to the need for Demand Control by being in a short contracted position. Despite this short position, in the majority of examples (5 out of 8), this Supplier is made better off following Demand Control under P138. This appears to provide a perverse incentive whereby Suppliers who contribute to the need for Demand Control could benefit from its instruction.

The re-allocation of monies resulting from P138 fails to provide any incentive on industry parties to change behaviours from those currently displayed. As such P138 fails to better facilitate BSC Applicable Objective (c).

3. Do you believe Proposed Modification P138 has a negative impact on Applicable BSC Objective (d) Promoting efficiency in the implementation and administration of the balancing and settlement arrangements

Arguments For (i.e. P138 has a negative impact on applicable BSC Objective (d)):

The process proposed under P138 will add significant complexity to the implementation and administration of the Balancing and Settlement Arrangements and therefore P138 will be to the detriment of Applicable BSC Objective (d). As well as this increased complexity, it will also add uncertainty and increase risk for Parties operating within the industry. There will be significantly different BSUoS charges, Imbalance prices and RCRC payments as a result of P138 and parties will have to wait until at least 48 hours after the end of each Demand Control Settlement Period before knowing the impact that the P138 calculations will have on them and on Parties that they trade with. The information required to determine the effect of P138 cashflows on any given party will not be available prior to the completion of the II Run.

Where a change to the process of managing the balancing and settlement arrangements results in the inability to provide prompt prices, increased uncertainty and volatility, greater scope for error, increased costs and a risk of discrimination, it cannot better facilitate Applicable BSC Objective (d).

The process associated with the implementation and administration of the changes proposed by P138 has been hugely simplified. As a result of the necessary simplification of the procedures proposed to affect the P138 objectives, estimates are used to calculate other estimates, which in turn determine potentially significant changes in industry cash flows resulting in a lottery of P138 winners and losers.

P138 not only simplifies the proposed process through the use of estimates to drive key calculations, but also simplifies those calculations by making the assumption that some parties will not be impacted by Demand Control (e.g. embedded generators and directly connected demand). Whilst the logic used to justify their exclusion may be right in some cases, there may be times when P138 discriminates against such Parties as a result of their exclusion.

It would not be promoting efficiency in the implementation and administration of the Balancing and Settlement Arrangements if the costs associated with P138 were to be incurred as these costs do not outweigh the reputed benefits.

Arguments Against (i.e. P138 does not have a negative impact on Applicable BSC Objective (d)):

There are currently no contingency arrangements associated with Demand Control periods in the BSC. The proposal will address this defect and on this basis will better facilitate Objective (d) by promoting efficiency in the implementation and administration of the Balancing and Settlement Arrangements

The costs associated with implementing a manual solution for P138 do not have a negative impact on facilitating Applicable BSC Objective (d).

4. Overall, do you believe Proposed Modification P138 better facilitates the achievement of the Applicable BSC Objectives?

Arguments For:

Importing Supplier BM Units should be compensated for Demand Control instructions and with sight of the total costs, P138 will better facilitate achievement of the Applicable BSC Objectives.

On balance, the proposal better facilitates Objectives (b) and (c) for the reasons stated above, and may also better facilitate Objective (d).

Whilst Applicable BSC Objective (b) may not be better facilitated similarly it will not be adversely impacted either. There is a detrimental effect on Applicable BSC Objective (d) but this is outweighed by the benefits associated with Objective (c).

Arguments Against:

On balance, the potential benefits in terms of the small increase in intellectual purity of the arrangements are not worth the increase in complexity in the price setting arrangements.

The only aspect of P138 that better facilitates any of the Applicable BSC Objectives is the treatment of Demand Control Volumes that removes the perversity of making Suppliers better off following Demand Control as a result of the resultant effect on Metered Volumes and imbalance positions. This is outweighed by the detrimental impact that the rest of P138 would have on Applicable BSC Objectives (b), (c) and (d).

The benefit of P138 is more than out weighed by the detrimental impact that P138 would have on Applicable BSC Objectives (b), (c) and (d) including making windfall payments to Suppliers, increasing the risk of greater uncertainty and volatility in the market and in certain circumstances possibly perversely making Demand Control a more likely event.

5. Do you support the implementation approach described in the consultation document / the implementation option preferred by the Modification Group?

Arguments For:

Taking into account the fact that Demand Control is unlikely to occur very often, there should be minimal system impact from this proposal and it should be inexpensive to implement. If this is not the case the downside of Objective (d) could outweigh the benefits provided under Objective (c).

A solution based on the lowest cost of implementation is appropriate since it is difficult to justify major system changes to accommodate a rare event.

Pricing a Demand Control Offer from the highest priced accepted Offer, that has not been tagged out, in the first Settlement Period in which Demand Control is instructed is the appropriate implementation option.

Arguments Against:

There is a pragmatic approach being taken in using estimates to determine the impact of Demand Control on Suppliers' Metered Volumes, however these very high level estimates will be used to determine what could be significant cashflows. The accuracy of the volume estimates will not only determine Demand Control Offer payments, but will affect imbalance volumes, imbalance payments and RCRC payments. A small error in the volume estimates could result in disproportionate impacts upon cashflows and the monies paid by and to each individual party. The fact that the total Demand Control Volume is based upon a high level estimate provided by the LDSO and is then allocated to Suppliers based upon an estimated market share derived from volumes taken from a completely different period, suggests that cashflows associated with P138 are little more than a lottery.

In respect of the "Demand Control Trigger", the suggestion that the end point should be determined as being the time the instruction was issued by the SO in accordance with OC6 (to begin restoring the demand) is not appropriate. There maybe sometime between the SO issuing an instruction (which may have a time lag built in) to the demand being restored to 'normal' (noting that historically when load is restored that circa 15% additional load 'returns'. If the load lost due to Demand Control is 100MW, then 115MW is the demand that comes back). It would be better if the end of the Demand Control period were determined as when the SO instruction has been carried out by the LDSO.

'The PSMG recognised that if other emergency measures were invoked these would override the P138 arrangements, effectively also constituting an end point to the Demand Control Period', however it is not clear what 'Emergency Supply Arrangements, under the Electricity Supply Emergency Code' are. This needs to be clarified, as it is possible that provisions of the Electricity Supply Emergency Code (such as orders to certain users to reduce demand) could be on-going whilst OC6 Demand Control is invoked / underway.

6. Do you believe there are any alternative solutions that would better facilitate the Applicable BSC Objectives to a greater degree than P138 (for example, adopting P138 with one of the suggested alternative pricing options or any other options that the Modification Group has not identified) that should be considered?

In considering whether there is an alternative to P138 that better facilitates the Applicable BSC Objectives, an alternative option is one that treats the volume associated with Demand Control, whilst reducing, or removing, the aspects of P138 that have a detrimental impact upon the Applicable BSC Objectives is an option. In this respect, all of the alternative means of pricing the Demand Control action better facilitate the Applicable BSC Objectives due to the fact that they result in a scaled reduction in the detrimental impact that the Proposed Modification has. Any alternative means of pricing the Demand Control Volume is better than the Proposed Modification.

Option of a Zero Price for the Demand Control Offer Price

By setting the Demand Control Offer Price to zero, the Proposed Modification will effectively put Suppliers' imbalance volumes back to the levels faced prior to the Demand Control action. This will be achieved without the detrimental affects of windfall payments, higher BSUoS payments, perverse incentives on Suppliers and the SO, or barriers to entry that are a characteristic of the Proposed Modification. However, the rules around tagging will have to be carefully considered as the inclusion of the Demand Control volume in the Offer stack at a zero price could have the negative effect of depressing average SBP. This would obviously be undesirable as at times of system stress, incentives on parties to balance should be at their greatest. Any dampening of SBP would be undesirable.

Option of a reverse price Demand Control Offer Price

There is an argument that the Demand Control Offer Price should be based upon the reverse price as opposed to the marginal price.

7. Do you agree with the PSMG's views of the scope of P138 in relation to those Parties covered / not covered by the Proposed Modification (see page 3 of the consultation document)?

Arguments For:

Demand Control based on Grid Code OC6, SO instructed events impacts on Supplier BM Units.

The proposed solution covers Supplier BM Units who do not usually participate in the BM. As stated in the consultation document directly connected BM Units are more likely to be BM participants and can give economic signals to the SO.

The scope of P138 provides a pragmatic and simple approach of implementing the proposal without incurring significant cost or requiring complex calculations to cover an event that is unlikely to occur on a frequent basis.

Arguments Against:

There are concerns that the potential size of Demand Control payments and increases in BSUoS charges etc. could discriminate against Direct Connected Demand and embedded generators in some circumstances.

8. Does P138 raise any issues that you believe have not been identified so far and that should be progressed as part of the Assessment Procedure?

The PSMG should ensure that there is an agreed understanding as to how the tagging mechanism will work following Demand Control in a post P138 environment. There is clearly a risk that the Demand Control offer could be tagged out as a result of CADL or De-Minimis tagging. This will obviously dampen any incentive on parties to balance by reducing the imbalance charges faced by those parties out of balance and contributing to the need for Demand Control to be initiated.

9. Are there any further comments on P138 that you wish to make?

The frequency of Demand Control is rare and therefore the costs should to be kept to a minimum, i.e. manual processes where possible. Without the Impact Assessments it would have been difficult to determine whether P138 better facilitates achievement of the Applicable BSC Objectives.

The Business Requirements Specification and the P138 Mechanism documents indicate that, following initiation of Demand Control, the SO is expected to provide details of the affected GSP group(s), the affected LDSO(s), the amount of Demand Control requested as both a percentage reduction and actual volume. At the point of initiation, the SO will not know which GSP Group(s) is affected as it will instruct Demand Control from an LDSO and leave the LDSO to decide how and where the instruction is delivered. Similarly, at the point of instruction, the SO will ask an LDSO to deliver stage one Demand Control. This will reflect a percentage reduction in demand, across the LDSO's network, of between 4 and 6 percent in line with their submission to the SO on an annual basis. The SO will not ask for a specific volume of Demand Control to be delivered. As a result of the limited information available at the point of initiation, the SO will only be able to confirm the start time and details of which LDSO has been asked to initiate Demand Control under OC6.

Immediately following the instruction to an LDSO to reconnect demand, the SO may not know or be able to estimate the volume of demand reduced as part of the Demand Control instruction. As such it may be difficult to provide an estimate of the reduced volume delivered by the Demand Control action until some time after the notice is published detailing the end time of the Demand Control period.

6.2 Comments and Views of the Modification Group

The PSMG discussed each consultation question and the responses received to each question.

1. Do you believe Proposed Modification P138 better facilitates the achievement of Applicable BSC Objective (b) The efficient, economic and co-ordinated operation by the Transmission Company of the Transmission System?

A number of the PSMG considered that P138 did not better facilitate Applicable BSC objective (b) as it did not provide any better signals to the market to balance, especially in times of system stress, and that Demand Control is an operational tool not an economic one.

Other members of the PSMG believed that P138 would better facilitate applicable BSC objective (b) as it may encourage the SO to procure energy in a more efficient way at times of system stress, and that the SO would be faced with a cost for any Demand Control measures. Others were concerned that the signal presented by the cost of Demand Control could be wrong, and that, in any event, the seriousness of Demand Control was such that basing it on a commercial signal may not be reasonable and prudent.

Other members of the PSMG believed that although P138 did better facilitate Applicable BSC Objective (b) in principle, it was such a rare event that there would be no change in the behaviour of the SO in fulfilling its current responsibilities.

Ultimately, the PSMG were split between those who considered that P138 better achieved Applicable BSC Objective (b), those who believed that although Applicable BSC Objective (b) was better achieve in theory, no such better achievement would arise in practice and those who did not believe that P138 better achieved Applicable BSC Objective (b).

2. Do you believe Proposed Modification P138 better facilitates the achievement of Applicable BSC Objective (c) Promoting effective competition in the generation and supply of electricity, and (so far as consistent therewith) promoting such competition in the sale and purchase of electricity?

Some members of the PSMG believed that allowing the SO to take Demand Control as a free action (i.e. the SO effectively buying energy for free) is a fundamental defect in the Code and so P138 better facilitated Applicable BSC Objective (c). Added to this, it increased SBP during times of system stress. Some members of the PSMG also believe that currently the cost of Demand Control is targeted onto those Participants affected by the Demand Control and that under P138, the cost of the Demand Control would be shared by all Participants through BSUoS.

Other members of the PSMG believed that P138 does not better facilitate Applicable BSC Objective (c) due to the new risks it introduced though increased BSUoS (as Participants, not the SO will ultimately pay for the Demand Control Offer through BSUoS). Furthermore, some members of the PSMG believed that if a system warning message were issued, notifying a possibility of Demand Control, it may change Parties behaviour and encourage a short position since if Demand Control were invoked, the Party would receive a Marginal Price for their Demand Control Offer, which would be greater than the SBP that they would be charged for their short fall in energy.

Some members of the PSMG believed that although P138 would not better facilitate Applicable BSC Objective (c) (as they believed that there is no current defect in the Code), they also believed that it would not have an adverse impact on Applicable BSC Objective (c).

Ultimately, the PSMG were split between those who considered that Applicable BSC Objective (c) was better achieved, those who considered that Applicable BSC Objective (c) was not better achieved and those who considered that there would be no impact on Applicable BSC Objective (c).

3. Do you believe Proposed Modification P138 has a negative impact on Applicable BSC Objective (d) Promoting efficiency in the implementation and administration of the balancing and settlement arrangements

Some members of the PSMG believed that P138 had an adverse impact on Applicable BSC Objective (d) as it increases complexity for no benefit.

Some members of the PSMG believed that since the cost to implement P138 would be modest, it better facilitates Applicable BSC Objective (d) as it puts in place an efficient process for the payment of Suppliers for Demand Control Offers.

A majority of the PMSG considered that, whilst there was a negative impact on Applicable BSC Objective (d), that impact was modest.

4. Overall, do you believe Proposed Modification P138 better facilitates the achievement of the Applicable BSC Objectives?

A number of the PSMG believed P138 better facilitates the Applicable BSC Objectives for the reasons given above.

A number of the PSMG believed that P138 does not better facilitate the Applicable BSC Objectives for the reasons given above.

A number of the PSMG believed that Suppliers should be compensated for Demand Control but the solution offered in P138 was not the correct way for the Demand Control to be compensated,

The PSMG could not reach a consensus on any of the above views, and there were similar numbers of members of the PSMG supporting each view (similar to the responses received to the consultation).

5. Do you support the implementation approach described in the consultation document / the implementation option preferred by the Modification Group?

The PSMG supported the consultation responses and agreed that a manual solution should be adopted for P138 as it is a rare event.

The PSMG discussed the end time for the period of Demand Control and whether the end time of the Demand Control should reflect the point in time when the Demand is fully restored as this would be a more accurate time for the end of the Demand Control Period. The PSMG recognised that although it would be desirable to define the end time of the Demand Control as the point in time that Demand is restored, this would be subjective as there are defined timescales or indicators for demand to be restored and therefore not possible to define. The PSMG noted that the SO would only give an instruction for the reconnection of Demand when the system was able to support that Demand and so that would be a valid end time for the Demand Control. The PSMG therefore believed that the only defining point for the end of the Demand Control would be the time that the notice is given to the LDSO from the SO to begin to reconnect demand, noting also that the whole of the Settlement Period within which the instruction to reconnect demand is given would be considered to be a Demand Control Settlement Period.

The PSMG discussed the interaction of P138 with Electricity Supply Emergencies and fuel Security Periods. Apart form the issue of whether market rules would be modified under such conditions, the PSMG also noted that, under an Electricity Supply Emergency, there would be rota disconnections and it would be difficult to distinguish between such disconnections and those instructed by the SO. The PSMG therefore reaffirmed their view that P138 should not have effect if such emergency arrangements were invoked.

6. Do you believe there are any alternative solutions that would better facilitate the Applicable BSC Objectives to a greater degree than P138 (for example, adopting P138 with one of the suggested alternative pricing options or any other options that the Modification Group has not identified) that should be considered

The PSMG discussed two alternative modifications suggested by consultation responses.

The first option for an alternate modification is that of setting the Demand Control Offer Price to zero.

A Majority of the PSMG believed that this option is does not better facilitate the Applicable BSC Objectives compared to the Proposed Modification, or compared to current practise as Suppliers would not only not receive anything for their Demand Control Offer, but would also then be further penalised by their market position being taken back to where it would have been had the Demand Control not occurred. Under current arrangements, Suppliers are, to some extent, compensated for their Demand Control Offer by their Metered Volume reflecting the Demand Control.

A minority of the PSMG believe that setting the Demand Control Offer Price to zero would better facilitate the Applicable BSC objectives than the Proposed Modification as it would ensure that Parties' positions would reflect what they would have been had the Demand Control not occurred and so those Parties that were short and could have been said to have been causing the Demand Control would remain as short and therefore have to pay SBP for their imbalance, whilst not leading to any windfall payments to any Parties. It was noted that if the Demand Control Offer Price were zero, further consideration would have to be given as to how the Demand Control Offer would feed into the Bid Offer Stack, without suppressing the imbalance prices.

The second option for an alternate modification was that of setting the Demand Control Offer Price to the Market Index Price. Some members of the PSMG believed that in this way Parties would not receive windfall payments for their Demand Control Offers and so it would lessen the possible perceived incentive to contract short during periods of system stress, and it would incentivise trading in the forward markets at times of system stress as Parties would receive a similar price for the Demand Control Offer to what had been paid for that energy in the forward market. Other members of the PSMG believed that the Market Index Price would not provide the correct signal to balance at times of system stress. The PSMG also noted that if the Market Index Price was used as the Demand Control Offer Price, and it was fed into the Imbalance calculations, it would suppress SBP at times of system stress. The PSMG agreed that SBP should not be suppressed at times of system stress. Some members of the PSMG also believed that setting a price for the Demand Control of the marginal price would set a price at which the SO could initiate Demand Control.

The PSMG therefore believed that setting the Demand Control Offer Price to the Market Index Price may provide compensation for the Demand Control but would not provide a strong price signal during periods of system stress.

The PSMG could not agree on an alternative to P138 that would better achieve the applicable BSC Objectives.

7. Do you agree with the PSMG's views of the scope of P138 in relation to those Parties covered / not covered by the modification (see page 3 of the consultation document)?

The PSMG believe that the scope of P138 is correct.

8. Does P138 raise any issues that you believe have not been identified so far and that should be progressed as part of the Assessment Procedure?

The PSMG discussed CADL tagging in respect of P138. The PSMG noted that due to the mechanism chosen for the implementation of the solution of P138, if the total Demand Control was shorter in duration than fifteen minutes, the whole of the Demand Control would be tagged by the CADL. The

PSMG believe that this would be correct as a Demand Control Period of less than fifteen minutes would be taken for System Balancing reasons. The PSMG noted that if the Demand Control was longer in duration than fifteen minutes, even it if spanned two Settlement Periods and was less than fifteen minutes in each of the two Settlement Periods, it would not be tagged out by the CADL. The PSMG also noted that under current CADL tagging, if a BM Unit has an acceptance for less than fifteen minutes in any Settlement Period, then all acceptances on that BM Unit in that Settlement Period would be CADL tagged. The group noted that due to the implementation method chosen, the Demand Control Offer on any BM Unit that had an acceptance that was subject to CADL tagging would not be CADL tagged. The PSMG agreed that the legal drafting to the Code would recognise this.

9. Are there any further comments on P138 that you wish to make?

The PSMG noted the comments made by the SO and agreed that the SO would notify on the BMRA the LDSO affected by the Demand Control as opposed to the GSP Group. The PSMG agreed that BSCCo would provide the SAA mapping details of the LDSO and GSP Group to facilitate the rest of the mechanism for P138.

It was also acknowledged that OC7 (Reference 3) of the Grid Code may need to be changed to ensure that notifications and information provided by the SO under P138 would be consistent with confidentiality provisions.

7 IMPLEMENTATION APPROACH

P138 requires change to the Code and Code Subsidiary documents and the development of a number of SAA scripts. The costs and timescales for the implementation of P138 are included in section 3. P138 will be implanted as part of a BSC systems release as this is more cost effective and efficient. ELEXON will be responsible for managing the implementation of P138

8 DOCUMENT CONTROL

8.1 Authorities

Version	Date	Author	Reviewer	Change Reference
0.1	10/11/03	Katie Key	PSMG	P138AR01
0.2	1/12/03	Katie Key	Peer review	P138AR02
0.3	4/12/03	Katie Key	Peer review	P138AR03

8.2 References

Ref	Document	Owner	Issue date	Version
Reference 1	Operating Code No. 6 (OC6)	National Grid Company	15 October 2001	Revision 3
Reference 2	Operating Code No. 1 (OC1)	National Grid Company	30 September 2002	Revision 8
Reference 3	Operating Code No. 7 (OC7)	National Grid Company	24 November 2003	Revision 12

ANNEX 1 DRAFT LEGAL TEXT

- Draft Legal Text for the Proposed Modification is included as Annex 1 and attached as a separate document.

ANNEX 2 MODIFICATION GROUP DETAILS

The PSMG have met six times during the assessment for P138. The details of the Modification Group members, and the meetings that each attended are detailed in the table below.

Name	Company	Member	15/ 09	02/ 10	10/ 10	23/ 10	15/ 11	26/ 11
Justin Andrews	ELEXON (Chairman)	Y	√	√	√			
Neil Cohen	ELEXON (Chairman)	Y				√	√	√
Katie-Ann Key	ELEXON (Lead Analyst)	Y	√	√	√	√	√	√
Bill Reed	Innogy PLC (Proposer)	Y	√	√	√	√	√	√
Ben Willis	Npower	Y		√		√		
Mark Manley	BGT	Y		√	√	√	√	√
Joanne Ellis	Cornwall Consulting	Y		√		√	√	√
John Costa	Edf Energy	Y	√		√	√	√	
Kevin Rendell	National Grid Transco	Y	√		√	√	√	√
Martin Mate	British Energy	Y	√	√	√	√		
Paul Jones	Powergen	Y	√		√	√		√
Ron Slade	Edf Energy	Y	√	√	√			√
Chris Pooley	Campbell Carr	Y	√					
Maurice Smith	Campbell Carr	N		√	√	√		
Vishal Patel	British Energy	N	√	√	√	√	√	√
Dena Harris	ELEXON	N	√	√		√		
Matt Buffey	Ofgem	N	√	√		√	√	√
Simon Bradbury	Ofgem	N			√			
Danielle Lane	BGT	N	√					
Louise Petchell	National Grid Transco	N		√				
Paul Mott	Edf Energy	N		√				
Jan Devito	Jade	N		√				
Ndidi Njoku	Ofgem	N					√	√
Garth Graham	Scottish and Southern	N						√
Rob Barnet	Campbell Carr	N						√

ANNEX 3 TERMS OF REFERENCE FOR MODIFICATION PROPOSAL P138

Modification Proposal P138 will be considered by the Pricing Standing Modification Group (PSMG) in accordance with the PSMG Terms of Reference.

P138 – Contingency arrangements in relation to implementation of Demand Control measures pursuant to Grid Code OC6 (Innogy plc)

1. ASSESSMENT PROCEDURE

1.1 The Modification Group will carry out an Assessment Procedure in respect of Modification Proposal P138 pursuant to section F2.6 of the BSC.

1.2 The Modification Group will produce an Assessment Report for consideration at the BSC Panel Meeting on 11 December 2003.

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

Whether the Modification Proposal is within the vires the BSC

Prior to discussions of the Modification Proposal, the Modification Group should consider the Decision Letters for Modification Proposals P59, P80 and P87, and establish whether the perceived defect is within the vires of the BSC.

Definition of Marginal Offer Price

Point 1 in the 'Description of Proposed Modification' states that Demand Control Instructions will be treated as Offers, with an Offer Price equal to the 'Marginal Offer Price prevailing for the Demand Control Settlement Period'. However, it does not explain in detail how this Marginal Offer Price should be calculated. Should the calculation take into account the various forms of tagging used in the calculation of System Buy Price (SBP) (e.g. De Minimis tagging, arbitrage tagging, Net Imbalance Volume (NIV) tagging)? Is it only Offers that are eligible to set the Marginal Price, or Energy Balancing Services Adjustment Data (BSAD) also?

It should be noted that a number of current pricing Mods (P135, P136 and P137) share the concept of a 'Marginal Offer Price' with P138. However, Section F requires that P138 be defined and assessed against the current BSC baseline. Therefore the Modification Group will need to define the 'marginal Offer price' in a way that's appropriate to P138 (which may not necessarily be the same definition that's appropriate for pricing purposes).

A further complexity with P138 is that it uses the Marginal Offer Price to set the price of Demand Control 'Offers'. Clearly, to avoid circularity, the Offer stack used to calculate the P138 marginal price will need to exclude those Demand Control 'Offers'. However, this doesn't necessarily mean that Demand Control 'Offers' should be excluded from the Offer stack used in the calculation of system prices. The Modification Group will need to take a view on this.

Interaction with Existing BSC Arrangements for Demand Control Instructions

Although P138 makes no mention of this, there are already arrangements in Grid Code BC2.9 and BSC Code Q5 to treat certain Demand Control Instructions as Bid Offer Acceptances. These provisions apply only to Demand Control Instructions issued in relation to a particular BM Unit (and not to Demand Control Instructions issued to an LDSO, which affect all Supplier BM Units in the affected GSP Group). However, the fact that there are these existing provisions raises the following issues:

- Should P138 apply to those Demand Control Instructions which are already covered by the BSC definition of Bid Offer Acceptance (BOA)? Or is it only intended to apply to those which currently aren't covered under the BSC?
- Given that there are these existing provisions, is it actually appropriate to introduce entirely new provisions into Section G? Possibly an alternative would be to extend the existing provisions in Grid Code BC2.9 and BSC Q5?

Mechanism for Calculating Demand Control Offer Profile

Point 3 in the 'Description of Proposed Modification' states that a 'Demand Control Offer Profile' would be derived from data provided by the Transmission Company. The Modification Group will need to clarify how this profile (assumed to be a Mega Watt (MW) profile similar to a Bid Offer Acceptance) could be derived. It should be noted in this context that the impact on Suppliers' Balancing Mechanism (BM) Unit Metered Volumes, of any reduction in a customer's Metered

Volumes, will vary depending on whether the customer has Half Hourly (HH) or Non-Half Hourly (NHH) metering:

- If the customer has HH metering, the reduction will be attributed to that customer's Supplier; but
- If the customer has NHH metering, the reduction will be smeared across all NHH Suppliers in the GSP Group.

Interaction with Non-Delivery Rules

In treating the Demand Control Instructions as Offer Acceptances, P138 presumably intends that the Lead Parties of the affected BM Units should have both their Energy Imbalance Cashflow and their BM Unit Cashflow adjusted:

- When calculating Energy Imbalance Charges, the Settlement system takes Offer Acceptances into account, insulating Parties from imbalance charges on the accepted volume.
- When calculating BM Unit Cashflows, the Settlement system pays for Offer Acceptances at the Offer Price (which in the case of P138 will be a marginal Offer price).

However, the Settlement system will only be able to achieve both these objectives if the Supplier BM Units affected have accurate Final Physical Notifications (FPNs). In general, this is likely to be harder for Supplier BM Units than for generators, due to their lack of control over their demand. Any inaccuracy in demand FPNs will potentially undermine the effectiveness of the P138 mechanism.

For example, suppose that Demand Control is invoked, reducing a Supplier BM Unit's Metered Volumes from 400 MW (200 MWh) to 360 MW (180 MWh). However, due to errors in demand forecasting the Supplier submitted an FPN of 350 MW. Under these circumstances, the error in the FPN will lead to Non-Delivery Rules 'clawing back' the Offer Payment:

- In order to reflect the Demand Control Instruction, an Acceptance must be entered into Settlement at the level of 310 MW (i.e. 40 MW below the 350 MW FPN). This will create a 20 MWh acceptance volume, to be taken into account in the Settlement process.
- However, because the original FPN was too low (i.e. 350 MW rather than 400 MW), the Offer Payment will be entirely 'clawed back' by Non-Delivery Charges.

The Modification Group may therefore need to consider the interaction between P138 and the rules for Non-Delivery Charges.

Impact on the Transmission Company

The Modification notes that there may be a requirement to amend OC6 of the Grid Code. Any likelihood of proposed change should be considered by the Modification Group prior to changes being developed via the normal route for changes to the Grid Code.

Interaction with Fuel Security Periods

The Modification Group should consider any interaction between Demand Control periods and Fuel Security periods.

Impact on Manifest Errors

It should be assessed whether this Modification could give rise to a new type of Manifest Error which would require a new procedure to be developed. The pricing process could be drawn out over fourteen months and would be handled through normal reconciliation runs, however, any new Manifest Error type would require a new disputes process to be developed.

Interaction with other Modifications

P135 'Marginal System Buy Price During Periods of Demand Reduction', P136 'Marginal Definition of the 'Main Energy Imbalance Price' and P137 'Revised Calculation of System Buy Price and System Sell Price'

P135, P136 and P137 have been raised and consider a Marginal pricing method as opposed to an average pricing method. P135 in particular looks at a marginal pricing mechanism during periods of Demand Control. Although P138 should be progressed against the current baseline, consideration should be given to its interaction with P135, P136 and P137.

P80 'Deemed Bid/Offer Acceptances for Transmission System Faults' and P87 'Removal of Market Risk Associated with the Operation of a Generator Inter-Trip Scheme'

The Modification Group should consider the issues raised in the Authority's decision letters for these Modification Proposals.

P71 'Transfer of Imbalances caused by Balancing Services to the Transmission Company Energy Account'

P71 introduced the concept of an Applicable Balancing Service (QAS). This is where the Transmission Company determines an energy volume associated with the provision of Balancing Services for a BM Unit and Settlement Period. These volumes are then removed for the Energy Account of the balancing service provider and transferred to the Energy Account of the Transmission Company, thus removing the balancing service provider from exposure to the consequences of Imbalance. The Modification Group should consider whether a similar approach could be adopted as the solution to P138.

Justification for P138

P138 asserts that (if the Modification is not made) Parties will be subject to high and unpredictable imbalance charges. The rationale for this is not entirely clear. In many cases Demand Control will have the effect of reducing the imbalance charges paid by Parties (by reducing their exposure to SBP, for example). The Modification Group may wish to consider the justification for P138

ANNEX 4 CONSULTATION RESPONSES

Consultation issued 20 November 2003

Representations were received from the following parties:

No.	Company	File Number	No. BSC Parties Represented	No. Non-Parties Represented
1.	Innogy	P138_ASS_001	9	0
2.	Aquila Networks	P138_ASS_002	1	0
3.	British Gas Trading (BGT)	P138_ASS_003	1	0
4.	EDF Energy	P138_ASS_004	9	0
5.	National Grid Transco	P138_ASS_005	1	0

No.	Company	File Number	No. BSC Parties Represented	No. Non-Parties Represented
6.	Powergen	P138_ASS_006	14	0
7.	Scottish and Southern Energy	P138_ASS_007	4	0

Respondent:	*Name* Bill Reed
No. of BSC Parties Represented	*9*
BSC Parties Represented	*Please list all BSC Parties responding on behalf of (including the respondent company if relevant).* Innogy plc, Innogy Cogen Limited, Innogy Cogen Trading Limited, Npower Limited, Npower Direct Limited, Npower Northern Limited, Npower Northern Supply Limited, Npower Yorkshire Limited, Npower Yorkshire Supply Limited
No. of Non BSC Parties Represented	
Non BSC Parties represented	*Please list all non BSC Parties responding on behalf of (including the respondent company if relevant).*
Role of Respondent	*(Supplier/Generator/ Trader / Consolidator / Exemptable Generator / BSC Agent / Party Agent / other – please state)* Supplier/Generator/ Trader / Consolidator / Exemptable Generator / Party Agent

	Question	Response	Rationale
1	Do you believe Proposed Modification P138 better facilitates the achievement of Applicable BSC Objective (b) The efficient, economic and co-ordinated operation by the Transmission Company of the Transmission System?	Yes	As noted in our Modification Proposal "The proposal will better facilitate Objective (b) in relation to the efficient, economic and co-ordinated operation by the Transmission Company of the Transmission System by ensuring that Demand Control periods can be effectively utilised under the BSC. Furthermore, the proposal will introduce appropriate incentives on NGC to ensure that the cost of demand control is appropriately targeted."
2	Do you believe Proposed Modification P138 better facilitates the achievement of Applicable BSC Objective (c) Promoting effective competition in the generation and supply of electricity, and (so far as consistent therewith) promoting such competition in the sale and purchase of electricity?	Yes	As noted in our Modification Proposal "By treating demand control as a BM action and removing the potential financial risks associated with Demand Control measures, the proposal will better facilitate Objective (c) of the BSC in relation to the promotion of 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. Specifically the proposal will remove the risk that parties are exposed to high and unpredictable imbalance charges and residual cashflow reallocation cashflows during a Demand Control Period."
3	Do you believe Proposed Modification P138 has a negative impact on Applicable BSC Objective (d) Promoting efficiency in the implementation and administration of the balancing and settlement arrangements	No	There are currently no contingency arrangements associated with demand control periods in the BSC. The proposal will address this defect and on this basis will better facilitate Objective (d) by promoting efficiency in the implementation and administration of the balancing and settlement arrangements

	Question	Response	Rationale
4	Overall, do you believe Proposed Modification P138 better facilitates the achievement of the Applicable BSC Objectives? Please give rationale and state objective(s)	Yes	The proposal better facilitates Objectives (b) and (c) for the reasons stated above, and may also better facilitate Objective (d).
5	Do you support the implementation approach described in the consultation document / the implementation option preferred by the Modification Group? Please give rationale	Yes	A solution based on the lowest cost of implementation is appropriate since it is difficult to justify major system changes to accommodate a rare event.
6	Do you believe there are any alternative solutions that would better facilitate the Applicable BSC Objectives to a greater degree than P138 (for example, adopting P138 with one of the suggested alternative pricing options or any other options that the Modification Group has not identified) that should be considered? Please give rationale	No	
7	Do you agree with the PSMG's views of the scope of P138 in relation to those Parties covered / not covered by the modification (see page 3 of the consultation document)? Please give rationale	Yes	Demand control based on Grid Code OC6 transmission operator instructed events impacts on supplier BMUs.
8	Does P138 raise any issues that you believe have not been identified so far and that should be progressed as part of the Assessment Procedure? Please give rationale	No	
9	Are there any further comments on P138 that you wish to make?	No	

Aquila Networks Plc response to P138 Assessment Consultation:

Please find that there is no impact to Aquila Networks Plc systems and/or processes.

Respondent:	Mark Manley
No. of BSC Parties Represented	
BSC Parties Represented	British Gas Trading (BGT)
No. of Non BSC Parties Represented	
Non BSC Parties represented	
Role of Respondent	

	Question	Response	Rationale
1	Do you believe Proposed Modification P138 better facilitates the achievement of Applicable BSC Objective (b) The efficient, economic and co-ordinated operation by the Transmission Company of the Transmission System?	No	BGT believe that this modification will have a negligible impact on the behaviour of the System Operator (SO) in maintaining an economic, efficient and co-ordinated Transmission System. BGT do not concur with the view that this will send the correct price signals to market participants to incentivise balance. The amendment to the imbalance price will be retrospective and as such will not provide a real time price signal that BSC Parties will be able to respond to.

	Question	Response	Rationale
2	Do you believe Proposed Modification P138 better facilitates the achievement of Applicable BSC Objective (c) Promoting effective competition in the generation and supply of electricity, and (so far as consistent therewith) promoting such competition in the sale and purchase of electricity?	Yes	BGT believe P138 will better facilitate effective competition in the sale and generation of electricity. There is a defect within the current methodology, which may benefit the party that caused the problem to the detriment of a party that attempted to balance their position. P138 will amend this to ensure all Parties contract positions are reflective of their notified position prior to demand control being initiated. BGT also supports removing the ability of the SO to call demand control and not paying for the instruction. BGT is unsure if the payment should be based upon a marginal action or if it more appropriate for the repayment to be based on the reverse price. BGT believes any solution should ensure that the volume associated with the demand control instruction is feed back into the derivation of the imbalance price. This will ensure that the NIV tagging process is more robust as it will be more accurate and it will also ensure that the energy imbalance price is more reflective of the actions taken by the SO.
3	Do you believe Proposed Modification P138 has a negative impact on Applicable BSC Objective (d) Promoting efficiency in the implementation and administration of the balancing and settlement arrangements	No	BGT agree that the modification adds cost and complexity to the processing of settlements and therefore this modification will be to the detriment of Applicable BSC Objective (d).
4	Overall, do you believe Proposed Modification P138 better facilitates the achievement of the Applicable BSC Objectives? Please give rationale and state objective(s)	Yes	Whilst BGT do not believe Applicable BSC Objective (b) will be better facilitated similarly BGT do not believe it will be adversely impacted either. BGT note the detrimental effect on Applicable BSC Objective (d) but believe these to be outweighed by the benefits associated with Objective (c).
5	Do you support the implementation approach described in the consultation document / the implementation option preferred by the Modification Group? Please give rationale	Yes	BGT support the implementation approach outlined by the Modification Group. The solution should have minimal system impact and it should be inexpensive to implement. If this is not the case the downside of Objective (d) could outweigh the benefits provided under Objective (c).

	Question	Response	Rationale
6	Do you believe there are any alternative solutions that would better facilitate the Applicable BSC Objectives to a greater degree than P138 (for example, adopting P138 with one of the suggested alternative pricing options or any other options that the Modification Group has not identified) that should be considered? Please give rationale	No	
7	Do you agree with the PSMG's views of the scope of P138 in relation to those Parties covered / not covered by the modification (see page 3 of the consultation document)? Please give rationale	Yes	BGT support the scope of the modification in terms of the Parties covered by the solution.
8	Does P138 raise any issues that you believe have not been identified so far and that should be progressed as part of the Assessment Procedure? Please give rationale	No	
9	Are there any further comments on P138 that you wish to make?	No	

Respondent:	Tony Dicicco
No. of BSC Parties Represented	9
BSC Parties Represented	EDF Energy Networks (EPN) plc; EDF Energy Networks (LPN) plc EDF Energy Networks (SPN) plc; EDF Energy (Sutton Bridge Power) EDF Energy (Cottam Power) Ltd; EDF Energy (West Burton Power) Ltd; EDF Energy plc; London Energy plc; Seeboard Energy Limited
No. of Non BSC Parties Represented	0
Non BSC Parties represented	N/A
Role of Respondent	Supplier/Generator/ Trader

	Question	Response	Rationale

	Question	Response	Rationale
1	Do you believe Proposed Modification P138 better facilitates the achievement of Applicable BSC Objective (b) The efficient, economic and co-ordinated operation by the Transmission Company of the Transmission System?	Yes	EDF Energy do recognise that Demand Control is an instruction issued to meet energy requirements, and we believe that Suppliers should be paid for demand shed under OC6. We also recognise that Demand Control is a rare event and often a last resort decision. We believe that introducing a price for Demand Control similar to other Balancing Mechanism actions will lead to the efficient and economic running of the Transmission System by the Transmission Company.
2	Do you believe Proposed Modification P138 better facilitates the achievement of Applicable BSC Objective (c) Promoting effective competition in the generation and supply of electricity, and (so far as consistent therewith) promoting such competition in the sale and purchase of electricity?	Yes	EDF Energy believe that importing Supplier BM Units in a GSP Group affected by Demand Control should not be exposed to increased imbalance exposure because of such an instruction. We believe that P138 would promote competition by removing this exposure.
3	Do you believe Proposed Modification P138 has a negative impact on Applicable BSC Objective (d) Promoting efficiency in the implementation and administration of the balancing and settlement arrangements	No	EDF Energy believe that the costs associated with implementing a manual solution for P138 do not have a negative impact on facilitating Applicable BSC Objective (d).
4	Overall, do you believe Proposed Modification P138 better facilitates the achievement of the Applicable BSC Objectives? Please give rationale and state objective(s)	Yes	EDF Energy believe that importing Supplier BM Units should be compensated for Demand Control instructions and with sight of the total costs EDF Energy believe that P138 will better facilitate achievement of the Applicable BSC Objectives.
5	Do you support the implementation approach described in the consultation document / the implementation option preferred by the Modification Group? Please give rationale	Yes	EDF Energy believe that pricing a Demand Control Offer from the highest priced accepted Offer, that has not been tagged out, in the first Settlement Period in which Demand Control is instructed is the appropriate implementation option.

	Question	Response	Rationale
6	Do you believe there are any alternative solutions that would better facilitate the Applicable BSC Objectives to a greater degree than P138 (for example, adopting P138 with one of the suggested alternative pricing options or any other options that the Modification Group has not identified) that should be considered? Please give rationale	No	
7	Do you agree with the PSMG's views of the scope of P138 in relation to those Parties covered / not covered by the modification (see page 3 of the consultation document)? Please give rationale	Yes	EDF Energy believe that the proposed solution covers Supplier BM Units who do not usually participate in the BM. As stated in the consultation document directly connected BM Units are more likely to be BM participants and can give economic signals to the System Operator.
8	Does P138 raise any issues that you believe have not been identified so far and that should be progressed as part of the Assessment Procedure? Please give rationale	No	
9	Are there any further comments on P138 that you wish to make?	Yes	It is unfortunate that the impact assessments were not available at the start of the P138 consultation. EDF Energy believe that as the frequency of demand control is rare we would want the costs to be kept to a minimum, i.e. manual processes where possible. Without the impact assessments it would have been difficult to determine whether P138 better facilitates achievement of the Applicable BSC Objectives.

Respondent:	***National Grid Transco***
No. of BSC Parties Represented	*1*
BSC Parties Represented	***National Grid Company***
No. of Non BSC Parties Represented	*0*
Non BSC Parties represented	*0*
Role of Respondent	**Transmission System Operator**

	Question	Response	Rationale
1	Do you believe Proposed Modification P138 better facilitates the achievement of Applicable BSC Objective (b) The efficient, economic and co-ordinated operation by the Transmission Company of the Transmission System?	**No**	See Below

Economic Incentive on the Transmission System Operator to avoid Demand Control

P138 states that National Grid currently has a perverse option to initiate Demand Control under OC6 as a 'free' option, thus suggesting that there is a higher probability of Demand Control being exercised. If Demand Control was an option available to National Grid as a balancing service that could be utilised based upon economic rationale, then it would be right and proper that Demand Control were priced and in doing so, Applicable BSC Objective (b) would be better facilitated.

However, Demand Control as instructed under OC6 of the Grid Code is **NOT** an option open to National Grid based upon economic rationale. If it were, National Grid would have made use of it as a justifiable balancing service long before now. The very fact that National Grid has not instructed Demand Control for such a long time clearly indicates that it is not seen as a 'free' option and is treated as an action to be 'avoided at all costs'. Charging National Grid for taking Demand Control will have no impact upon its behaviour. Demand Control will occur whether or not there is a cost associated with it. National Grid would take every feasible action, irrespective of price, prior to initiating Demand Control.

Demand Control is an operational decision taken as a result of either insufficient contracted reserve or failure the of the market to provide sufficient energy to meet demand. The level of contracted reserve is driven by National Grid's obligations in relation to Security of Supply. Putting a price on Demand Control, as suggested under P138, will not impact the level of reserve held and will do nothing to prevent insufficient generation being contracted by suppliers and the market failing. It will, as a result, fail to lead to the more efficient, economic or co-ordinated operation of the Transmission System. National Grid should not be penalised following the failure of the market over which it has limited control.

If the assertion, made by the proposer of P138, that National Grid will respond to the pricing of Demand Control is correct (a point strongly refuted by National Grid), then there could be a perverse incentive making it more likely that Demand Control is initiated. The modification proposes that National Grid pay for Demand Control at the marginal price. The Marginal Price is defined as the highest priced offer taken prior to the initiation of Demand Control. This could incentivise National Grid to take Demand Control earlier than would other wise have been the case, as the earlier it is initiated, the cheaper it will be. If this incentive is taken to its logical conclusion, Demand Control will be the first action taken by National Grid as it will be 'free' due to the fact that there is no offer price to set the cost of the action. Based upon this logic P138 fails to achieve its objective of making Demand Control less likely.

Based upon the same incorrect premise that National Grid will respond to the costing of Demand Control, it could be argued that National Grid would never take Demand Control, preferring to wait until the system begins to collapse in an uncontrolled manner and a Black Start situation occurs. This would avoid the need for National Grid to pay for the action at the prevailing marginal price as proposed by P138, but would obviously be an undesirable outcome for the wider industry and an inappropriate incentive for National Grid.

Sharpened incentive to balance through increased imbalance prices

The inclusion of deemed Demand Control Offers (at a marginal offer price) within the offer stack used to calculate imbalance prices (SBP/SSP), could lead to an increase in average SBP and thus supposedly increase the incentive on parties to balance. Whilst National Grid agrees with the principle of improving incentives on parties to balance, especially at times of system stress, it is believed that there are more appropriate means of achieving this (e.g. P136/P137). Imbalance Prices are only increased under P138 as a result of National Grid paying suppliers what is effectively a 'windfall' payment following Demand Control. This windfall payment may reduce incentives on suppliers to balance as it would reduce or negate any increase in imbalance cost exposure faced by suppliers who are in a 'short' contracted position. Without the perversions associated with windfall payments, the sharper incentives on parties' to balance would better facilitate Applicable BSC Objective (b). Unfortunately, the increase in imbalance prices is directly linked to the payment of such windfall gains.

Transmission Company Payment following an action that could have been avoided by the market more efficiently

National Grid believes that payment at a marginal price, by the System Operator, for Demand Control volume is in direct contradiction to Applicable BSC Objective (b) as it would almost certainly have been more efficient for the energy to be procured through forward contracts to ensure that sufficient was made available. If Demand Control is required due to a lack of available energy to meet demand, the market should be incentivised to contract for greater volumes. It can readily be assumed that the cost per MW of such contracting would be less than the marginal offer price P138 suggests is paid for every MW of demand reduced.

Previous industry views relating to sharper imbalance prices at times of Demand Control

Whilst not fully agreeing with the views made by industry participants in relation to P135, National Grid notes that the same counter arguments could be applied to the changes to imbalance prices and the signals provided to the market as a result of P138.

As with P135, it appears obvious that the P138 proposal would lead to increased uncertainty in relation to imbalance prices and Residual Cashflow Reallocation Cashflow (RCRC) payments at times of Demand Control. Under the proposal, the increase in imbalance prices, and resultant RCRC payments, would be dependent upon the volume associated with, and price at which, Demand Control is instructed. Neither the volume nor price, associated with the Demand Control action under P138, is predictable. As such, P138 will lead to increased uncertainty within the market.

Another argument against P135 was the inappropriate nature of post event calculations to determine cashout prices. National Grid notes that the proposed P138 mechanism relies upon post event calculation and allocation of volumes, identification of prices and calculation of payments. This means that prompt pricing becomes impossible during a Demand Control Period, a requirement that has previously been held as sacrosanct by market participants during other pricing modification discussions.

Similarly, market participants have previously indicated that pricing signals that only present themselves at times of Demand Control, come too late to affect behaviour as they are only seen after the event and can not be predicted. As such, higher imbalance prices that only occur following Demand Control will have no impact upon the contracting behaviour of industry participants.

National Grid further notes that it could be suggested that the P138 modification proposal results in the need for the development of a separate pricing regime that only operates at times of Demand Control. As industry participants have previously argued, this could be seen to be inefficient and to inappropriately introduce unnecessary complexity and uncertainty into the market.

If the above views expressed by other industry participants are valid, P138 clearly fails to better facilitate Applicable BSC Objective (b).

2	Do you believe Proposed Modification P138 better facilitates the achievement of Applicable BSC Objective (c) Promoting effective competition in the generation and supply of electricity, and (so far as consistent therewith) promoting such competition in the sale and purchase of electricity?	**No**	See Below

Treatment of volume associated with Demand Control

National Grid recognises that, under current arrangements, Suppliers' incentives to balance are dampened at times of Demand Control as the resultant reduction in metered volumes will generally improve affected Suppliers' imbalance positions. By treating Demand Control volumes as deemed offers, suppliers' contracted positions are changed such that their imbalance positions are not impacted by the Demand Control action. National Grid fully supports the removal of the current perversion that could reduce incentives on suppliers to balance at times of Demand Control. In this way, P138 does better facilitate Applicable BSC Objective (c).

In most cases P138 will appropriately account for the impact of Demand Control on Suppliers' contracted volumes. However, National Grid notes that this may not be the case where Demand Control is effected by disconnecting specific loads. In such a situation it will be quite clear which Supplier's metered volume will have been affected and which Supplier should receive the Demand Control Offer payment. However, the proposed P138 mechanism does not take account of this, effectively smearing the reduced volume across the whole Supplier community based upon their market shares within the GSP Group. This results in Demand Control Offer payments being made to Suppliers that were not affected by the Demand Control action, whilst the Supplier that lost significant metered volume will only receive a small element of the total Demand Control Offer payment that should have been received under the principles of P138.

Despite the acceptance that, in most cases, P138 appropriately accounts for the impact of Demand Control on Suppliers' contracted volumes, National Grid believes that other elements of P138 counteract the benefits of correctly accounting for the volumes associated with Demand Control resulting in an overall detrimental impact on Applicable BSC Objective (c).

Windfall Payments to Suppliers at times of Demand Control

National Grid believe it wholly inappropriate for Suppliers to be rewarded with, what equates to, a 'windfall' payment in the event of Demand Control. If payment is made at the Marginal Offer Price taken within the BM, this could provide perverse incentives on Suppliers as they will benefit when there is Demand Control. This can clearly be seen in the examples contained within the consultation document.

Increased costs for all parties through BSUoS charges

National Grid note that payment for deemed offers associated with Demand Control will be re-charged to the industry through BSUoS. BSUoS charges reflect the costs incurred by National Grid in balancing the system. The re-allocation of P138 costs through BSUoS charges results in parties not impacted by Demand Control paying for the windfall payments received by parties that are affected by Demand Control. Payment for Demand Control through BSUoS is based upon the total metered volumes of all market participants and has no relation to whether a party has contributed to the Demand Control initiation through their imbalance position. National Grid does not believe that it is appropriate for a Supplier to benefit from Demand Control, at the expense of other parties within the industry, when it could have been in a 'short' position and thus contributing to the need for Demand Control to be initiated.

The allocation of BSUoS charges is based upon metered volumes. As such National Grid further notes that ironically, those suppliers benefiting from windfall payments as a result of having their metered volumes reduced, will also benefit from reduced BSUoS, TNUoS and possibly DUoS charges, as these are all calculated as a factor of metered volume that will reduce following Demand Control. The recovery of total costs by National Grid is achieved through the general socialisation of costs across the community. Whilst affected suppliers benefit through reduced metered volumes, non-affected parties will face higher costs as their market share is artificially increased, seeing them incur a higher proportion of charges.

Barrier to entry for Smaller Suppliers

National Grid notes that the impact of increased BSUoS charges being incurred by all industry participants whilst payment following Demand Control being made to a limited number of suppliers based upon their metered volumes in a specific area, will discriminate against smaller suppliers. Smaller suppliers, or suppliers whose customer base is locational specific, are proportionately less likely to receive payment following demand control, but guaranteed to pay a proportional increase in BSUoS charges. This effect is in direct contradiction of Applicable BSC objective (c).

Re-allocation of monies around the industry

The eight examples, contained within the consultation document, clearly demonstrate that the net impact upon industry participants resulting from cashflows associated with P138 is completely arbitrary. The range of different volumes, prices, imbalance positions etc. that can be in place when Demand Control occurs means that no single party can be certain of being better or worse off. As a result, P138 is unlikely to change the behaviour of any participant. Demand Control will thus be just as likely to occur if P138 is approved as it is now. The modification provides no clear incentives that will change the behaviour of Generators or Suppliers from that that they currently display. As stated in response to question 1, the modification will have no impact upon the behaviour of National Grid.

From the examples contained within the consultation document, it can quite clearly be seen that, whilst generators are generally made worse off by P138 as a result of facing higher BSUoS charges without benefiting from any windfall payments, there could be situations where they benefit as a result of the increase in Residual Cashflow Reallocation Cashflow (RCRC) payments being greater than the increased BSUoS charges.

Similarly, Suppliers not affected by Demand Control (e.g. Supplier B) are generally worse off as a result of being subject to higher BSUoS costs without benefiting from payment for reduced volumes. However, these suppliers too could be made better off under P138 if RCRC payments outweigh the increased BSUoS charges.

In all examples Supplier C is contributing to the need for Demand Control by being in a 'short' contracted position. Despite this 'short' position, in the majority of examples (5 out of 8), Supplier C is made better off following Demand Control under P138. This appears to provide a perverse incentive whereby Suppliers who contribute to the need for Demand Control could benefit from its instruction.

The re-allocation of monies resulting from P138 fails to provide any incentive on industry parties to change behaviours from those currently displayed. As such P138 fails to better facilitate BSC Applicable Objective (c).

In summary, P138 seems to provide a windfall payment to affected Suppliers resulting in a seemingly haphazard re-allocation of costs around the community.

3	Do you believe Proposed Modification P138 has a negative impact on Applicable BSC Objective (d) Promoting efficiency in the implementation and administration of the balancing and settlement arrangements	Yes (has a negative impact & does not better facilititate)	See Below

The process associated with the implementation and administration of the changes proposed by P138 has been hugely simplified. As a result of the necessary simplification of the procedures proposed to effect the P138 objectives, estimates are used to calculate other estimates, which in turn determine potentially significant changes in industry cash flows resulting in a lottery of P138 winners and losers.

P138 not only simplifies the proposed process through the use of estimates to drive key calculations, but also simplifies those calculations by making the assumption that some parties will not be impacted by Demand Control (e.g. embedded generators and directly connected customers). Whilst the logic used to justify their exclusion may be right in some cases, there may be times when P138 discriminates against such parties as a result of their exclusion.

The process proposed under P138 will add significant complexity to the implementation and administration of the balancing and settlement arrangements. As well as this increased complexity, it will also add uncertainty and increase risk for parties operating within the industry. There will be significantly different BSUoS charges, Imbalance prices and RCRC payments as a result of P138 and parties will have to wait until 48+ hours after the end of each Demand Controlled settlement period before knowing the impact that the P138 calculations will have on them and on parties that they trade with. The information required to determine the effect of P138 cashflows on any given party will not be available prior to the completion of the Initial Settlement Run.

Where a change to the process of managing the balancing and settlement arrangements results in the inability to provide prompt prices, increased uncertainty and volatility, greater scope for error, increased costs and a risk of discrimination, it can not better facilitate Applicable BSC Objective (d).

4	Overall, do you believe Proposed Modification P138 better facilitates the achievement of the Applicable BSC Objectives? Please give rationale and state objective(s)	**No**	See Below

The only aspect of P138 that better facilitates any of the Applicable BSC Objectives is the treatment of Demand Control Volumes that removes the perversity of making Suppliers better off following Demand Control as a result of the resultant effect on metered volumes and imbalance positions.

This benefit of P138 is more than out weighed by the detrimental impact that the modification would have on Applicable BSC Objectives b, c and d.

In summary, Applicable BSC Objective (b) is made worse by:

- Requiring the System Operator to pay for an action that may have been avoided more efficiently by market participants;
- Increasing System Operator costs and thus BSUoS charges without changing behaviour or making Demand Control a less likely event;
- Potentially making either Demand Control or a blackout situation a more likely event;
- Increasing the risk of high and unpredictable Imbalance and RCRC payments; and
- Making windfall payments to suppliers that could lead to perverse incentives and increase the costs incurred in balancing the system.

Applicable BSC Objective (c) is made worse by:

- Restricting competition by creating a potential barrier to entry for smaller Suppliers;
- Inappropriately rewarding suppliers with windfall payments following Demand Control, potentially reducing incentives for suppliers to contract appropriately;
- Increasing costs for all industry participants through higher BSUoS charges; and
- Creating a lottery of winners and losers that has no bearing upon the effectiveness of a party's contracted position.

Applicable BSC Objective (d) is made worse by:

- Making high level assumptions and basing key calculations upon estimates rather than actual data;
- Increasing system and administration costs without positively changing behaviours or making Demand Control less likely;
- Increasing market uncertainty and volatility through unpredictable cash flows and delays in providing associated market information;
- Failing to feed Demand Control prices and volumes into Prompt Pricing calculations; and
- Creating a risk of inappropriately dealing with embedded generators and directly connected customers.

5	Do you support the implementation approach described in the consultation document / the implementation option preferred by the Modification Group? Please give rationale	**Yes (with reservations)**	See Below

Taking into account the fact that Demand Control is unlikely to occur very often, National Grid generally supports the proposal that "there should be minimal system impact form this proposal…"

However, whilst not disagreeing with the pragmatic approach being taken in using estimates to determine the impact of Demand Control on Suppliers' metered volumes, it does have concerns that these very high level estimates will be used to determine what could be significant cashflows. The accuracy of the volume estimates will not only determine Demand Control Offer payments, but will affect imbalance volumes, Imbalance payments and RCRC payments. A small error in the volume estimates could result in disproportionate impacts upon cashflows and the monies paid by and to each individual party. The fact that the total Demand Control volume is based upon a high level estimate provided by the Distribution System Operator and is then allocated to suppliers based upon an estimated market share derived from volumes taken from a completely different period, reinforces the fact that cashflows associated with P138 are little more than a lottery.

6	Do you believe there are any alternative solutions that would better facilitate the Applicable BSC Objectives to a greater degree than P138 (for example, adopting P138 with one of the suggested alternative pricing options or any other options that the Modification Group has not identified) that should be considered? Please give rationale	**Yes**	See below

National Grid has already explained in its response to questions 1 to 4 that, other than the lack of any current means of accounting for the volume associated with Demand Control, it does not believe that the defects assumed by P138 exist. In considering whether there is an alternative to P138 that better facilitates the Applicable BSC Objectives, it can only look at an alternative that treats the volume associated with Demand Control whilst reducing, or removing, the aspects of the modification that have a detrimental impact upon the BSC Objectives. In this respect, all of the alternative means of pricing the Demand Control Action better facilitate the BSC Objectives due to the fact that they result in a scaled reduction in the detrimental impact that the main proposal has. Any alternative means of pricing the Demand Control volume is better than the original modification.

Option of a Zero Price for the Demand Control Offer Price

By setting the Demand Control Offer Price to zero, the modification will effectively put Suppliers' imbalance volumes back to the levels faced prior to the Demand Control action. This will be achieved without the detrimental affects of windfall payments, higher BSUoS payments, perverse incentives on Suppliers and the System Operator, or barriers to entry that are a characteristic of the main modification proposal.

National Grid supports the development of an alternative to the main P138 proposal that has a zero value for the Demand Control Offer Price. However, it notes that the rules around tagging will have to be carefully considered as the inclusion of the Demand Control volume in the Offer stack at a zero price could have the negative effect of depressing average SBP. This would obviously be undesirable as at times of system stress, incentives on parties to balance should be at their greatest. Any dampening of SBP would be undesirable.

7	Do you agree with the PSMG's views of the scope of P138 in relation to those Parties covered / not covered by the modification (see page 3 of the consultation document)? Please give rationale	**Yes (with reservations)**	See Below
National Grid supports the PSMG's view of the scope of P138 in that it provides a pragmatic and simple approach of implementing the proposal without incurring significant cost or requiring complex calculations to cover an event that is unlikely to occur on a frequent basis. However, it does have concerns that the potential size of Demand Control payments and increases in BSUoS charges etc. could discriminate against direct connected and embedded Generators in some circumstances.			
8	Does P138 raise any issues that you believe have not been identified so far and that should be progressed as part of the Assessment Procedure? Please give rationale	**Yes**	See Below
National Grid believes that the PSMG should ensure that there is an agreed understanding as to how the tagging mechanism will work following Demand Control in a post P138 environment. There is clearly a risk that the Demand Control offer could be tagged out as a result of CADL or De-minimus tagging. This will obviously dampen any incentive on parties to balance by reducing the imbalance charges faced by those parties out of balance and contributing to the need for Demand Control to be initiated.			

9	Are there any further comments on P138 that you wish to make?	**Yes**	See Below

National Grid Notes that the Business Requirements Specification and the P138 Mechanism documents indicate that, following initiation of Demand Control, the System Operator is expected to provide details of the affected GSP group(s), the affected LDSO(s), the amount of Demand Control requested as both a percentage reduction and actual volume. At the point of initiation, the System Operator will not know which GSP Group(s) is affected as it will instruct Demand Control from a Local Distribution System Operator (LDSO) and leave the LDSO to decide how and where the instruction is delivered. Similarly, at the point of instruction, the System Operator will ask an LDSO to deliver stage one Demand Control. This will reflect a percentage reduction in demand, across the LDSO's network, of between 4 and 6 percent in line with their submission to the Transmission System Operator on an annual basis. The System Operator will not ask for a specific volume of Demand Control to be delivered. As a result of the limited information available at the point of initiation, the System Operator will only be able to confirm the start time and details of which LDSO has been asked to initiate Demand Control under OC6.

Immediately following the instruction to an LDSO to reconnect demand, the System Operator may not know or be able to estimate the volume of demand reduced as part of the Demand Control instruction. As such it may be difficult to provide an estimate of the reduced volume delivered by the Demand Control action until some time after the notice is published detailing the end time of the Demand Control period.

Respondent:	Powergen
No. of BSC Parties Represented	14
BSC Parties Represented	Powergen UK plc, Powergen Retail Limited, Cottam Development Centre Limited, TXU Europe Drakelow Limited, TXU Europe Ironbridge Limited, TXU Europe High Marnham Limited, Midlands Gas Limited, Western Gas Limited, TXU Europe (AHG) Limited, TXU Europe (AH Online) Limited, Citigen (London) Limited, Severn Trent Energy Limited (known as TXU Europe (AHST) Limited), TXU Europe (AHGD) Limited and Ownlabel Energy Limited
No. of Non BSC Parties Represented	-
Non BSC Parties represented	-
Role of Respondent	Supplier, Generator, Trader & Exemptable Generator.

	Question	Response	Rationale
1	Do you believe Proposed Modification P138 better facilitates the achievement of Applicable BSC Objective (b) The efficient, economic and co-ordinated operation by the Transmission Company of the Transmission System?	No	Even though treating the amount of demand reduction as an offer appears the correct intellectual thing to do, it is not clear that it will send a sufficient signal to participants to improve balancing or to ensure sufficient plant is available. The proposal suffers from the same problem as P135. That is, the signal will be sent too late, as it comes once the event has actually occurred. It is possible for imbalance prices to send signals to participants when past imbalance prices alter expectations of likely future levels. However, this mechanism will be used infrequently meaning that participants will have insufficient experience of the relevant prices for it to alter their future expectations.
2	Do you believe Proposed Modification P138 better facilitates the achievement of Applicable BSC Objective (c) Promoting effective competition in the generation and supply of electricity, and (so far as consistent therewith) promoting such competition in the sale and purchase of electricity?	No	It is not clear that the present treatment of demand control is acting as a deterrent to competition in supply.
3	Do you believe Proposed Modification P138 has a negative impact on Applicable BSC Objective (d) Promoting efficiency in the implementation and administration of the balancing and settlement arrangements	Yes	It will increase the complexity of the price setting arrangements.
4	Overall, do you believe Proposed Modification P138 better facilitates the achievement of the Applicable BSC Objectives? Please give rationale and state objective(s)	No	On balance, we do not believe that the potential benefits in terms of the small increase in intellectual purity of the arrangements are worth the increase in complexity in the price setting arrangements.
5	Do you support the implementation approach described in the consultation document / the implementation option preferred by the Modification Group? Please give rationale	No	

	Question	Response	Rationale
6	Do you believe there are any alternative solutions that would better facilitate the Applicable BSC Objectives to a greater degree than P138 (for example, adopting P138 with one of the suggested alternative pricing options or any other options that the Modification Group has not identified) that should be considered? Please give rationale	No	
7	Do you agree with the PSMG's views of the scope of P138 in relation to those Parties covered / not covered by the modification (see page 3 of the consultation document)? Please give rationale	Yes	
8	Does P138 raise any issues that you believe have not been identified so far and that should be progressed as part of the Assessment Procedure? Please give rationale	No	
9	Are there any further comments on P138 that you wish to make?	No	

This response is sent on behalf of Scottish and Southern Energy, Southern Electric, Keadby Generation Ltd., SSE Energy Supply Ltd. and Medway Power Ltd.

In relation to the nine questions listed in the Consultation Paper, contained within your note of 10th November 2003 concerning Modification Proposal P138, we have the following comments to make:-

Q1 Do you believe Proposed Modification P138 better facilitates the achievement of Applicable BSC Objective (b) The efficient, economic and co-ordinated operation by the Transmission Company of the Transmission System?

No. Demand Control is (and should remain) a purely operationally driven decision taken by the SO to ensure the overall system stability and implemented via Emergency Instructions. It is not a 'commercial' decision taken by the SO (such 'commercial' decisions being taken by the SO via the other means such as the BM, PGBTs etc.).

In this respect we fundamentally oppose any suggestion that "the SO should be financially incentivised not to use it" as this implies (if the incentive is not 'sufficient') that the SO might consider (from a financial / commercial perspective) to invoke Demand Control. In the very rare event that Demand Control is used it should only be utilised to ensure the overall stability of the system. In this respect the SO should only consider the technical aspect of maintaining the integrity of the system and should not take account of any financial consideration.

Q2 Do you believe Proposed Modification P138 better facilitates the achievement of Applicable BSC Objective (c) Promoting effective competition in the generation and supply of electricity, and (so far as consistent therewith) promoting such competition in the sale and purchase of electricity?

No. It is not clear that the statement that "any of those Parties that were short (and therefore could be said to causing the Demand Control)" is correct in all circumstances. It may be that there is a shortfall in area A, but due to system constraints etc., that the System Operator chooses to invoke Demand Control in area B and that Party X is short in area C. Given the system set up it could well be that Party X has not caused Demand Control to be invoked in area B, so should not be exposed to a higher SBP.

Furthermore we do not believe it is appropriate for the PSMG to consider (in respect of "Other Demand Control Offer Price Options") that "it would not reward Suppliers for what could be regarded as a market failure".

Firstly, why should Suppliers be "rewarded" for doing nothing? The choice of which GSP to be subject to Demand Control is chosen by the SO, without any involvement of Suppliers who thus take no action (to be 'rewarded').

It is appropriate that Suppliers are held neutral; i.e. do not incur costs (where Demand Control is invoked) for something they are not responsible for (being out of balance in a Demand Control area due to the action taken by the SO); but Suppliers should not receive a windfall profit; i.e. be rewarded; for these events. This issue (of rewarding a Supplier for doing nothing) is compounded when it is noted (in respect of "Volume") "that the volume estimation would not reflect reality and....would not necessarily allocate demand reductions accurately", which is turn is exacerbated by the proposition that the volume allocation rules should be based on an "equivalent day" methodology. The worked example, where August 28th would be considered 'equivalent' to October 2nd, shows how inappropriate and inefficient this methodology would be.

Secondly, it is not clear that the market has failed (and, if it has, why are we not relying on the Section G Contingency arrangements) as the Demand Control could, for example, be invoked due to system problems. This is not a failure of the market, as there is no market for the system itself – we have only one System Operator.

Q3 Do you believe Proposed Modification P138 has a negative impact on Applicable BSC Objective (d) Promoting efficiency in the implementation and administration of the balancing and settlement arrangements

Yes. In addition to the reasons outlined in our response to Q1 and Q2 above we believe it would not be promoting efficiency in the implementation and administration of the balancing and settlement arrangements if the costs associated with this Modification Proposal were to be incurred as these costs do not outweigh the reputed benefits.

Q4 Overall, do you believe Proposed Modification P138 better facilitates the achievement of the Applicable BSC Objectives? Please give rationale and state objective(s)

No. For the reasons outlined in our response to Q1, Q2 and Q3 above.

Q5 Do you support the implementation approach described in the consultation document / the implementation option preferred by the Modification Group? Please give rationale

In respect of the "Demand Control Trigger", the suggestion that the end point should be determined as being the time the instruction was issued by the SO in accordance with OC6 (to begin restoring the demand) is not appropriate. There maybe sometime between the SO issuing an instruction (which may have a time lag built in) to the demand being restored to 'normal' (noting that historically when load is restored that circa 15% additional load 'returns' - if the load lost due to demand control is 100MW, then 115MW is the demand that comes back). It would be better if the end of the Demand Control period were determined as when the SO instruction has been carried out by the LDSO.

In regard to the comments that "the PSMG recognised that if other emergency measures were invoked.....these would override the P138 arrangements, effectively also constituting an end point to the Demand Control Period"; it is not clear what "Emergency Supply Arrangements, under the Electricity Supply Emergency Code" are. This needs to be clarified, as it is possible that provisions of the Electricity Supply Emergency Code (such as orders to certain users to reduce demand) could be on-going whilst OC6 Demand Control is invoked / underway).

Q6 Do you believe there are any alternative solutions that would better facilitate the Applicable BSC Objectives to a greater degree than P138 (for example, adopting P138 with one of the suggested alternative pricing options or any other options that the Modification Group has not identified) that should be considered? Please give rationale

Q7 Do you agree with the PSMG's views of the scope of P138 in relation to those Parties covered / not covered by the modification (see page 3 of the consultation document)? Please give rationale

Q8 Does P138 raise any issues that you believe have not been identified so far and that should be progressed as part of the Assessment Procedure? Please give rationale

Q9 Are there any further comments on P138 that you wish to make?

We have nothing further to add at this time.

ANNEX 5 TRANSMISSION COMPANY ANALYSIS

In accordance with paragraph F 2.8 of the Code, please respond to the following questions concerning P138 (including the rationale for each response):

Q	Question	Response
1	Please outline any impact of the Proposed Modification (and, if applicable, any Alternative Modification) on the ability of the Transmission Company to discharge its obligations efficiently under the Transmission Licence and on its ability to operate an efficient, economical and co-ordinated transmission system.	No impact has been identified resulting from this modification proposal on the ability of the Transmission Company to discharge its obligations under the Transmission Licence.
2	Please outline the views and rationale of the Transmission Company as to whether the Proposed Modification (and, if applicable, any Alternative Modification) would better facilitate achievement of the Applicable BSC Objectives.	We do not believe that the modification proposal better facilitates the BSC Applicable Objectives. We do not believe it is appropriate for the Transmission Company to pay for an Emergency Instruction for Demand Control, which will result in a windfall payment to Suppliers. Our more detailed views on this issue will be incorporated within our response to the Assessment Consultation for Modification P138.
3	Please outline the impact of the Proposed Modification (and, if applicable, any Alternative Modification) on the computer systems and processes of the Transmission Company, including details of any changes to such systems and processes that would be required as a result of the implementation of the Proposed Modification (and, if applicable, any Alternative Modification	No impact has been identified on our computer systems as a result of this proposed modification, however we would have to make changes our documented procedures and working instructions covering the areas of System Warnings and Demand Control to give effect to the modification.
4	Please provide an estimate of the development, capital and operating costs (broken down in reasonable detail) which the Transmission Company anticipates that it would incur in, and as a result of, implementing the Proposed Modification (and, if applicable, any Alternative Modification).	Minimal costs have been identified.
5	Please provide details of any consequential changes to Core Industry Documents that would be required as a result of the implementation of the Proposed Modification (and, if applicable, any Alternative Modification).	There may be a potential impact on the Grid Code resulting from this proposed modification and we are currently reviewing the relevant documentation. We will provide feedback on our conclusions as soon as it is available.
6	Any other comments on the Proposed Modification (and Alternative Modification if applicable).	No other comments.

ANNEX 6 BSC AGENT IMPACT ASSESSMENTS

NETA Change Form		ELEXON Reference
		P138
Title		**Version No.**
Contingency arrangements in relation to implementation of Demand Control measures pursuant to Grid Code OC6		0.2
		LogicaCMG Reference
		ICR554
Type of Assessment	**Date CP Received**	**Date IA Issued**
N/A	31/10/03	19/11/03

Brief Summary of Change

A process needs to be developed that will come into operation if Demand Control is invoked. The process will (for each settlement period that occurs within Demand Control) determine and enter new FPN, Bid-offer pair and Acceptance data for each supplier BM Unit impacted by Demand Control.
This DLIA is against the P138 Requirements Specification v1.0 dated 31 October 2003 [P138AS].

LogicaCMG's Proposed Solution

The process is a mixture of automated scripts and manual procedures. Various options are proposed which require varying proportions of manual intervention. A full system solution is also proposed to allow ELEXON to consider all possible solutions to the problem.

Non-System Solutions

An overview of the steps to be performed per settlement period of Demand Control invocation is given below:

1. Calculate the demand control price. This will require running the SAA II run (without issuing reports) to calculate acceptance volumes in order to determine the price
2. Identify all supplier BM Units in the GSP Group. This requires extraction of volumes for that day and period
3. Determine the proportion of demand per BM Unit and demand control volume
4. Extract of demand capacity for all affected BM Units
5. Derivation of FPN data and Bid-Offer data using the demand control price as the offer price having pair size at least as big as the computed demand control volume and Acceptance
6. Manual entry of:
   - Derived FPN
   - New bid-offer pair
   - Acceptance
7. Check data after entry

The work involved for each step is described in more detail here:

Step 1 Perform the II run without issuing the results. Develop script to determine demand control price [select MAX(QPAQ) where QPAQ>DMAT]

Step 2 Develop a script to identify supplier BM Units (type S or G) that were importing (QM < 0) for the relevant GSP Group for that period on the most recent SF run. If the equivalent period value is zero, then the prior period (possibly prior day) will be examined. The associated metered volume is recorded against each BM Unit

Step 3 Develop a script to take the output from step 2 and determine the proportion of demand per BM Unit and demand control volume. The GSP Group demand control volume is the total of the BM Unit metered volumes. The proportion of demand per BM Unit is calculated by dividing the metered volume of each BM Unit by the GSP Group demand control volume. Each BM Unit individual demand control volume is then calculated by multiplying the total demand control volume as supplied by the SO by the BM Unit's proportion of the GSP Group demand

Step 4 Develop a script to extract the demand capacity for all impacted BM Units

Step 5 Develop a script to derive FPN data, Bid-offer data (offer price equal to demand control price, offer volume equal to demand control volume) and acceptance data for all impacted BM Units

Note: Steps 2 – 5 would be developed as a single script for efficiency

Step 6 Manual process to enter generated data from step 5. Expected to be between 50 and 100 BM Units impacted per settlement period per demand control invocation

Step 7 Develop a script to check data entered in step 6. This takes the data generated in step 5 and reads database to confirm correct data entry

<u>Options</u>

There are many permutations to how these tasks may be performed. These are explained in this section.

Demand Control Price

The calculation of the demand control price (Step 1) could be calculated in 4 ways, which produce the following 4 permutations:

Option 1 Use the marginal price

Option 2 Use the market index price – same development effort as option 1

Option 3 Use the marginal price with a cap – same development effort as option 1

Option 4 Use a fixed price – removes the need for Step 1

BM Unit Deemed Demand

The calculation of the BM Unit Deemed Demand (Steps 2 – 5) could be calculated by SAA or by BSCCo. If BSCCo performs the work, the development effort for these steps is removed. This section doubles the number of permutations to 8.

Data Entry

The data entry (Step 6) could be automated. This has the advantage of reducing the time required to perform the entire process and also removes the need for checking the manual data entry (Step 7). An automated script would add new development effort, but significantly reduce the effort to perform the operation. If Steps 2 – 5 are performed by BSCCo (see above) this automated script would also need to load and validate a CSV file from BSCCo to allow the output of Steps 2 – 5 to be input into Step 6. This section adds a further 8 permutations.

LogicaCMG Alternative

As it currently stands, the BRS does not cover the situation where demand side acceptances exist prior to Demand Control being invoked. In reality this situation is bound to exist and in order to handle it, the process of calculating the FPN, Bid-offer pair and Acceptance data would need to be modified. A mechanism for determining what acceptance number to use would also be needed. The proposed LogicaCMG Alternative process will be able to handle existing acceptances and also has the advantage of removing the large manual data entry activity, which reduces the execution time and effort of the process. The work involved is as follows:

1. Develop script to calculate the demand control price
2. Develop script to calculate the BM Unit Deemed Demand
3. Manually modify QAS flow so that Demand Control balancing action is taken into account for each impacted BM Unit
4. Enter FPN, Bid-offer and Acceptance data against a single dummy 'Demand Control' BM Unit

so that the stack is adjusted correctly and NGC are charged for the Demand Control activity

5. Develop script to determine the cashflow for each impacted BM Unit relating to the Demand Control activity, taking into account Transmission Loss Multiplier values
6. Develop script to identify the parties impacted by the Demand Control action
7. Manually modify the relevant SAA-I013 flow to ECVAA so that the position of the impacted parties is corrected
8. Send a manual flow to FAA with details of the impacted parties and the related BM Unit prices

If Step 2 is performed by BSCCo, the development effort for this step is removed.
This sections adds a further 8 permutations, which gives a total of 24 possible permutations in this assessment, but because options 1, 2 and 3 for calculation of Demand Control Price require the same development effort, the number of distinct price permutations is reduced to 12. These are labelled A to K and are summarised in the following table:

Other Alternatives	Manual Data Entry				Automated Data Entry				LogicaCMG Alternative			
BM Unit Deemed Demand	SAA		BSCCo		SAA		BSCCo		SAA		BSCCo	
Demand Control Price	Option 1, 2 or 3	Option 4	Option 1, 2 or 3	Option 4	Option 1, 2 or 3	Option 4	Option 1, 2 or 3	Option 4	Option 1, 2 or 3	Option 4	Option 1, 2 or 3	Option 4
Option Reference Id	A	B	C	D	E	F	G	H	I	J	K	L

Full System Solution

This proposed solution involves amending SAA so that the Demand Control calculations would be carried out as part of the Settlement Run process. The loading of GSP Group demand control volume data from the SO would be a manual process, as would the extraction and reporting of demand control data to BSCCo (i.e. SAA-I014 would be unchanged). The tasks involved are as follows:

1. Create new tables:
   DEMAND_CONTROL(Date, Period, GSP GROUP SID, Demand Control Volume, Demand Control Price)
   DEMAND_CONTROL_BMU(Date, Period, BMU SID, Demand Control Volume, Demand Control Price)
2. Amend the Settlement Calculation:
   a. Ensure that Demand Control processing can be invoked for the II run and only that run
   b. The demand control price is calculated and populated in the DEMAND_CONTROL table against each GSP Group and period that a volume is in that table for that day. This will only be done for II runs
   c. The BM Unit Deemed Demand will be calculated for each period and GSP Group in the DEMAND_CONTROL table, and that data will be written to the DEMAND_CONTROL_BMU table. This will only be done for II runs
   d. Amend F005 module so that the QBS for each BM Unit includes data from the DEMAND_CONTROL_BMU table for all runs
   e. Amend F009 module so that the Demand Control Volume for each GSP Group is included in the Offer Stack for all runs, where there is data in the DEMAND_CONTROL table
   f. Amend F007 module so that the calculation for party cashflow (CBM) includes data from the DEMAND_CONTROL_BMU table for all runs as if they were acceptances

Deviation from ELEXON's Solution / Requirements					
LogicaCMG has suggested an alternative solution to deal with the situation where demand side acceptances exist prior to Demand Control being invoked (see previous section).					
Operational Solution and Impact					
Non-System Solutions Operation of the Demand Control process will involve the following tasks: • Manual data entry • Service Delivery support • Second Line support These tasks will be charged T&M. Scheduling of Demand Control Process In order to meet the existing II Settlement Run timetable the Demand Control Process needs to start on D+3. It is expected that the process of calculating the BM Unit Deemed Demand would take 0.5 days to complete (either by SAA or BSCCo). For those options which require the calculation of the Demand Control Price by performing the II run it would be necessary to carry out the Aggregation Process on the afternoon of D+2 and hence all estimation activity would need to be complete by midday on D+2. Under normal circumstances this is achievable, but there is a risk of the II run being delayed. Similarly, if more than one settlement period is impacted for a single day by a Demand Control invocation or Demand Control is invoked more than once in a single week there is a risk of the II run being delayed due to the workload generated by the manual data entry. This risk does not apply to the options that remove the need for manual data entry. **Full System Solution** The operational tasks are as follows: 1. The SO would send the GSP Group Demand Control Volumes to SAA via an adhoc manual flow 2. These would be entered into the DEMAND_CONTROL table via an adhoc script 3. The II Settlement Run would then be carried out as per normal 4. The relevant data would then be extracted from the system database tables using adhoc scripts and be sent to BSCCo as a manual flow for publication to parties					
Testing Strategy					
Unit	X	Change Specific	X	End to End	
Module	X	Operational Acceptance	X	Participant Testing	
System	X	Performance		Parallel Running	
Regression		Volume		Deployment/ Backout	X
Other:					
Validated Assumptions					
None.					
Outstanding Issues					
None.					

Changes to Service

Services Impacted

	BMRA	CDCA	CRA	ECVAA	SAA	TAA	Other
Software					X		
IDD Part 1 (Docs)							
IDD Part 1 (S'Sheet)							
IDD Part 2 (Docs)							
IDD Part 2 (S'Sheet)							
URS					X		
SS					X		
DS					X		
MSS							
OSM					X		
LWIs					X		
RTP	None						
Comms	None						
Other	None						

Nature of Documentation Changes

Non-System Solutions
SAA OSM, SAA LWI
Full System Solution
SAA URS, SAA SS, SAA DS, SAA OSM, SAA LWI

Nature / Size of System Changes

Medium

Type of Release Costed:	Standalone patch
Deployment Issues, eg Outage Requirements:	None
Impact on Service Levels:	None
Impact on System Performance:	None

Responsibilities of ELEXON

Within reasonable levels, ELEXON will make available appropriate staff to assist LogicaCMG during the development of this change.

Acceptance Criteria

N/A

Any Other Information

The information imbalance price is currently set to zero. If this values is made non-zero, the processes described in this assessment will not function correctly and this modification must be reassessed.
We have some comments on the P138 BRS and these are attached to this assessment.

Attachments

P138 Price Presentation v0.1 P138 Marked-Up SAA URS v0.1 P138 BRS Review Comments v0.1		
PRICING		
Price Breakdown		
Item description	**Remarks**	**Price (ex VAT)**
Development	Non-System Solutions: A B C D E F G J I J K L	 £22,204 £18,585 £8,573 £6,724 £24,053 £22,204 £23,128 £21,279 £17,660 £15,811 £8,573 £6,724
Change Specific	Full System Solution	£162,750
Release Cost	Full System Solution	£307,472
Total Price		£470,221
Price Tolerance	Non-System Solutions Full System Solution	15% 20%
Project Duration	Non-System Solutions Full System Solution	6 weeks 16 weeks
Operational Price		T&M
Rationale		
See Price Presentation. All estimates are based on a single run through the Demand Control process for a single settlement period, for 100 impacted BM Units.		
Annual Maintenance Price	Full System Solution	£22,785
Rationale		
The Annual Maintenance Price is derived as 14% of the Change Specific Price of the software changes		

Validity Constraints
• Price excludes provision for indexation of daily rates from 1st April 2004 • Price and duration assume that this change is developed in isolation and the effects of other changes are excluded • No allowance is included for the final solution being different from the BRS • Price is for creating DCRs, not a formal documentation issue • No allowance is included for Information Imbalance price being non-zero • No allowance is included for supporting PwC activities. Any effort will be charged at contracted T&M rates • No allowance is included for supporting ELEXON assurance activities. Any effort will be charged at contracted T&M rates • No allowance is included for End to End/Participant Testing activities. Any effort will be charged at contracted T&M rates • No allowance is included for Walkthrough activities. Any effort will be charged at contracted T&M rates The validity period for this quote is 30 days and the offer is based on the following payment schedule: • For the non-system solutions, LogicaCMG will invoice in full for this change on deployment or within one month of the change being ready for deployment • For the full system solution, LogicaCMG will invoice 30% on receipt of Purchase Order or authorised start of work, 30% on completion of first build phase, 30% on live implementation and 10% on successful completion of the Success Criteria or one month after live implementation, whichever is sooner • Maintain charges will be invoiced monthly in arrears with part months charged pro rata. • Operate charge invoicing will be deferred until the de minimis limit has been reached

Authorised Signature	Date Signed

ANNEX 7 BSCCO IMPACT ASSESSMENTS

a CVA Programme

Assessor Name	Andy Holland	Assessor Team	CVA Programme	Date	1/12/03
1. Does this Impact your Department?	Yes				

2. System Impacts?	Yes		
Description: Business Process Model – new page			
Total Resources (man days) (Development)	5	Lead time	4 weeks
4. Documentation Impacts?	Yes		

Description: **BMRA SD** **SAA SD, URS, SS, DS, OSM,** **Workaround 018**			
Total Resources (man days) (Development)	**41 (+ 20** for release overheads)	**Lead time**	**12 weeks**
7. Any other Comments or Assumptions made:			
Assumes no system changes as specified in business requirements specification.			
Overall Lead Time for Project			**12 weeks**

b CVA Operations

Assessor Name	Darren Bourke	**Assessor Team**	**CVA Operations**	**Date**	
1. Does this Impact your Department?					
5. Operational Impacts?					
Description: It appears that a manually operated solution will be strongly favoured. If this is the case CVA Operations will need to be involved in developing a workable process and producing an LWI to capture this process. As CVA Operations have also been heavily involved in other work relating to Section G and Q and changes to these sections of the BSC may have associated implications on other areas. I would need 10 man days to develop a robust process plus 3 days to review and test this process. A further 2 days would be allowed for the production of the LWI and up to 5 days to determine any affects of changes to Section G and Q of the BSC. If the SAA automated solution is the preferred option CVA Operations would still be involved in reviews and testing but 5 many days should be sufficient to cover this.					
Ongoing Resources (man days per annum) (Post-implementation)					**20 Days or** **5 Days**
Overall Lead Time for Project					

c Market Monitoring

Option 1 - SAA Perform All Calculations

Assuming that there are no changes to the SAA I014 flows, there would be no impact on Market Monitoring.

Option 2 - BSC Co Perform Calculations Manually

Assuming that BSCCo are not required to report the revised price for Demand Control Periods in Best View Prices (on the BSC web site) there is no impact on Market Monitoring.

Option 3 - BSC Co Perform Calculations Automatically

A new screen and table would be required in TOMAS to specify the details of, and trigger calculations for the Demand Control. TOMAS could then generate a set of acceptances under run type "NA" - previously used for "NGC - ABD based Runs" - containing a copy of BMRA acceptances and the additional required acceptances for Demand Control to become W018 acceptances. A TOMAS Report would be required to relay this information to the CAA. The TOMAS Requirements Catalogue, System Design, Data Catalogue and LWI would all be impacted. Development and Documentation is estimated to take 10 days with a further 10 days for System Testing and Document Reviews. 5 days should be allowed for CVA Programme Integration/E2E testing of the software/process and a further 5 days for Management of these changes to MMR products. Total: 30 days.

d Assurance

Assessor Name	Richard Smith	Assessor Team	Assurance	Date	14/11/03
1. Does this Impact your Department?			Yes		

3. Process Impacts?	**Yes**		
Description: **The provision of assurance to the CVA programme for the implementation of this mod is estimated to be 5 man days.** **Please refer the original IA from assurance (12/08) for additional information.**			
Total Resources (man days) (Development)	**5**	**Lead time**	
4. Documentation Impacts?	Yes		
Description: **Obligations Register – estimated at 0.5 man days** **ELEXON view of BPM – estimated at 1 man day**			
Total Resources (man days) (Development)	**1.5**	**Lead time**	
Overall Lead Time for Project			

Assessor Name	Richard Smith	Assessor Team	For Assurance Dept.	Date	12/08/03
1. Does this Impact your Department?			Yes		
2. System Impacts?	**See below**				
Description: **Assurance Dept (Disputes) is working with Service Delivery (Market Monitoring) to specify and develop calculators to support the Post-Final Extra Settlement Determination process. These calculators will need to reflect any Settlement Day based changes to the pricing rules. Please ensure that there is an impact statement from Market Monitoring on this area.**					
Total Resources (man days)		**Lead time**			

(Development)			
3. Process Impacts?	**Yes**		
Description: **It should be assessed whether this modification could give rise to a new type of manifest error which would require a new procedure to be developed. The DA suggested that the pricing process could be drawn out over the 14 month settlement period and so handled through normal reconciliation runs. However, any new manifest error type (incorrect demand shutdown?) would impact Disputes requiring a new process to be developed.** **No impact expected on the Post-final ESD process being developed as it will be generic** **No impact on Performance Assurance or BSC Audit processes** **No impact on P6 processes as this rule change is outside the Settlement Day window relevant to P6** **The assurance to be provided for the implementation of this modification would be similar in scale to P78. At this early stage some 40 man-days programme assurance is estimated for the CVA Programme and for the internal ELEXON systems (e.g. TOMAS if changed) for the delivery of this mod.**			
Total Resources (man days) (Development)	**40**	**Lead time**	**0**
4. Documentation Impacts?	**Yes**		
Description: **Obligations Register – estimated at 0.5 man days** **ELEXON view of BPM – estimated at 1 man day** **No impact anticipated on ESD documentation as it will be generic**			
Total Resources (man days) (Development)	**1.5**	**Lead time**	**2 weeks**
5. Operational Impacts?	**No**		
Description: **Assume that this MP will not increase the level of Trading Disputes (see 3 above)**			
Ongoing Resources (man days per annum) (Post-implementation)			
7. Any other Comments or Assumptions made:			
1. This MP should be assessed as High business risk by ELEXON as it has a material impact on Settlement. **2. Delivery would be via the CVA Programme and ELEXON internally (if TOMAS impacted). PwC will be performing the Development audit for the relevant BSC Agents and Systems Assurance will be performing the Development Audit for ELEXON.**			
Overall Lead Time for Project			

e Governance & Regulatory Affairs

Assessor Name	**Laone Roscorla**	**Assessor Team**	**Governance & Regulatory Affairs**	**Date**	**11 Aug 03**

1. Does this Impact your Department?	**Possibly**	
5. Operational Impacts?	**Possibly**	
Description: Depending on the decided process adopted, there could be an increase in workload of the Panel which oversees most of the Section G provisions.		
Ongoing Resources (man days per annum) (Post-implementation)	**Not known**	
Overall Lead Time for Project		

f Communications

As with the assessment provided by Communications for P135, I would expect the impact of P138 to be similar, should a workaround solution be implemented. Therefore, it may be necessary to modify web page text within the Pricing Data section and to amend the text on each individual TOMAS web price report published within the Pricing Data section to indicate demand reduction.

I would allow 5 man days for this work, including development and testing. The BSC (ELEXON) website URS would also need to be updated (allow 1 day).

Please do let me know if additional information becomes available that might have an impact on what is a high level impact assessment.

g Strategic Commercial Services

No Impact

h Finance

No Impact

ANNEX 8 CASH FLOW MODELLING EXAMPLES

In the eight attached examples, the same generic assumptions have been made. These assumptions are detailed below.

The market share of each Supplier, for a given GSP Group, will affect the extent to which Demand Control impacts upon their Metered Volumes. It has been assumed that each Supplier's market share within each GSP is as indicated in table 1 below.

Table 1

Supplier Market Share for each GSP Group				
	GSP 1	GSP 2	GSP 3	GSP 4
Supplier A	5	25	10	30
Supplier B	50	20	0	5
Supplier C	10	25	60	35
Supplier D	20	30	25	30
Supplier E	15	0	5	0

Similarly, the total Demand, prior to Demand Control, in each of the four GSP Groups is assumed to be as shown in table 2.

Table 2

Total Demand in each GSP Group				
	GSP 1	GSP 2	GSP 3	GSP 4
MWh	5,000	7,500	12,250	2,500

The imbalance position, prior to Demand Control, of each of the five Suppliers and four generators that is assumed in each of the examples is outlined in table 3

Table 3

Imbalance Position prior to Demand Control			
Supplier A	+100 long	Generator F	0 balanced
Supplier B	0 balanced	Generator G	0 balanced
Supplier C	-250 short	Generator H	0 balanced
Supplier D	+100 long	Generator I	-200 short
Supplier E	0 balanced		

For simplicity, in each example it has been assumed that Demand Control has been initiated in GSP Group 3 and results in a reduction in Metered Volume of 250 MWh.

Each of the eight examples reflect the actual volumes and prices experienced during settlement periods where the SO have issued a DRI, HRHR or NISM warning.

The dates, settlement periods and associated live system warnings relating to the eight examples are shown in table 4.

Table 4

Dates and Settlement Period used for each example								
Example	1	2	3	4	5	6	7	8
Period	25	35	35	35	24	25	25	35

Date	28/06/01	15/11/01	21/11/02	10/12/02	14/07/03	15/07/03	21/07/03	11/08/03
Message	NISM	NISM	NISM	DRI	HRDR	HRDR	NISM	HRDR

The other key inputs into the model are:

- SBP calculated without the deemed Demand Control Offer (as it is now)
- SBP calculated with the deemed Demand Control Offer (under P138)
- Market Index Price; and
- Demand Control Offer Price (in these examples taken as the marginal offer)

For each example these are detailed in table 5.

Table 5

Key inputs into cash flow model for each example								
Example	1	2	3	4	5	6	7	8
SBP calculated without Demand Control Offer	£282	£144	£85	£255	£296	£301	£362	£258
SBP calculated with Demand Control Offer	£306	£324	£262	£305	£355	£345	£375	£321
Market Index Price	£41	£52	£163	£116	£104	£109	£154	£281
Demand Control Offer Price	£334	£453	£270	£450	£430	£430	£380	£430

These details were entered into the model. Table 6 shows the model's outputs for each example. The Net position of each Party shows the amount that each Party in the model would have lost or gained under P138, compared to the current baseline.

Table 6

Difference in Net Cash Flows with P138 - Example 1

	Sup A	Sup B	Sup C	Sup D	Sup E	Gen F	Gen G	Gen H	Gen I	NGT
Marginal Offer Price revenue	£8,350	£0	£50,100	£20,875	£4,175	£0	£0	£0	£0	-£83,500
Imbalance Cost	-£1,014	£0	-£48,395	-£2,536	-£507	£0	£0	£0	£0	£0
RCRC	£3,958	£4,007	£10,150	£6,799	£1,311	£7,285	£2,914	£4,857	£11,170	£0
Increased BSUOS	-£6,301	-£6,378	-£16,159	-£10,824	-£2,088	-£11,597	-£4,639	-£7,731	-£17,782	£83,500
Net Position	**£4,992.76**	**-£2,371.74**	**-£4,303.19**	**£14,314.61**	**£2,891.67**	**-£4,312.25**	**-£1,724.90**	**-£2,874.83**	**-£6,612.12**	**£0.00**

Difference in Net Cash Flows with P138 - Example 2

	Sup A	Sup B	Sup C	Sup D	Sup E	Gen F	Gen G	Gen H	Gen I	NGT
Marginal Offer Price revenue	£11,325	£0	£67,950	£28,313	£5,663	£0	£0	£0	£0	-£113,250
Imbalance Cost	-£1,295	£0	-£66,512	-£3,238	-£648	£0	£0	£0	-£35,945	£0
RCRC	£8,123	£8,222	£20,830	£13,953	£2,691	£14,950	£5,980	£9,966	£22,923	£0
Increased BSUOS	-£8,546	-£8,651	-£21,916	-£14,681	-£2,831	-£15,729	-£6,292	-£10,486	-£24,118	£113,250
Net Position	**£9,606.45**	**-£428.75**	**£351.64**	**£24,347.43**	**£4,874.68**	**-£779.54**	**-£311.82**	**-£519.70**	**-£37,140.39**	**£0.00**

Difference in Net Cash Flows with P138 - Example 3

	Sup A	Sup B	Sup C	Sup D	Sup E	Gen F	Gen G	Gen H	Gen I	NGT
Marginal Offer Price revenue	£6,750	£0	£40,500	£16,875	£3,375	£0	£0	£0	£0	-£67,500
Imbalance Cost	-£4,075	£0	-£56,930	-£10,188	-£2,038	£0	£0	£0	-£35,350	£0
RCRC	£8,194	£8,294	£21,012	£14,075	£2,715	£15,081	£6,032	£10,054	£23,124	£0
Increased BSUOS	-£5,094	-£5,156	-£13,063	-£8,750	-£1,688	-£9,375	-£3,750	-£6,250	-£14,375	£67,500
Net Position	**£5,775.04**	**£3,138.07**	**-£8,480.27**	**£12,012.72**	**£2,364.51**	**£5,705.59**	**£2,282.24**	**£3,803.73**	**-£26,601.61**	**£0.00**

Difference in Net Cash Flows with P138 - Example 4

	Sup A	Sup B	Sup C	Sup D	Sup E	Gen F	Gen G	Gen H	Gen I	NGT
Marginal Offer Price revenue	£11,250	£0	£67,500	£28,125	£5,625	£0	£0	£0	£0	-£112,500
Imbalance Cost	-£2,900	£0	-£50,791	-£7,250	-£1,450	£0	£0	£0	-£9,973	£0
RCRC	£5,461	£5,528	£14,004	£9,380	£1,809	£10,051	£4,020	£6,700	£15,411	£0
Increased BSUOS	-£8,490	-£8,594	-£21,771	-£14,583	-£2,813	-£15,625	-£6,250	-£10,417	-£23,958	£112,500
Net Position	**£5,321.19**	**-£3,065.97**	**£8,942.01**	**£15,672.13**	**£3,171.59**	**-£5,574.50**	**-£2,229.80**	**-£3,716.33**	**-£18,520.31**	**£0.00**

Difference in Net Cash Flows with P138 - Example 5

	Sup A	Sup B	Sup C	Sup D	Sup E	Gen F	Gen G	Gen H	Gen I	NGT
Marginal Offer Price revenue	£10,750	£0	£64,500	£26,875	£5,375	£0	£0	£0	£0	-£107,500
Imbalance Cost	-£2,589	£0	-£59,257	-£6,471	-£1,294	£0	£0	£0	-£11,942	£0
RCRC	£6,154	£6,230	£15,782	£10,572	£2,039	£11,327	£4,531	£7,551	£17,368	£0
Increased BSUOS	-£8,112	-£8,212	-£20,803	-£13,935	-£2,688	-£14,931	-£5,972	-£9,954	-£22,894	£107,500
Net Position	**£6,203.51**	**-£1,982.02**	**£221.54**	**£17,040.33**	**£3,432.09**	**-£3,603.67**	**-£1,441.47**	**-£2,402.44**	**-£17,467.86**	**£0.00**

Difference in Net Cash Flows with P138 - Example 6

	Sup A	Sup B	Sup C	Sup D	Sup E	Gen F	Gen G	Gen H	Gen I	NGT
Marginal Offer Price revenue	£10,750	£0	£64,500	£26,875	£5,375	£0	£0	£0	£0	-£107,500
Imbalance Cost	-£2,725	£0	-£56,082	-£6,813	-£1,363	£0	£0	£0	-£8,804	£0
RCRC	£5,719	£5,789	£14,666	£9,824	£1,895	£10,526	£4,210	£7,017	£16,140	£0
Increased BSUOS	-£8,112	-£8,212	-£20,803	-£13,935	-£2,688	-£14,931	-£5,972	-£9,954	-£22,894	£107,500
Net Position	**£5,631.74**	**-£2,422.63**	**£2,280.88**	**£15,951.37**	**£3,219.64**	**-£4,404.78**	**-£1,761.91**	**-£2,936.52**	**-£15,557.80**	**£0.00**

Difference in Net Cash Flows with P138 - Example 7

	Sup A	Sup B	Sup C	Sup D	Sup E	Gen F	Gen G	Gen H	Gen I	NGT
Marginal Offer Price revenue	£9,500	£0	£57,000	£23,750	£4,750	£0	£0	£0	£0	-£95,000
Imbalance Cost	-£3,850	£0	-£57,477	-£9,625	-£1,925	£0	£0	£0	-£2,599	£0
RCRC	£5,696	£5,766	£14,606	£9,784	£1,887	£10,483	£4,193	£6,989	£16,074	£0
Increased BSUOS	-£7,169	-£7,257	-£18,384	-£12,315	-£2,375	-£13,194	-£5,278	-£8,796	-£20,231	£95,000
Net Position	**£4,176.70**	**-£1,491.37**	**-£4,255.56**	**£11,594.18**	**£2,336.91**	**-£2,711.59**	**-£1,084.64**	**-£1,807.73**	**-£6,756.92**	**£0.00**

Difference in Net Cash Flows with P138 - Example 8

	Sup A	Sup B	Sup C	Sup D	Sup E	Gen F	Gen G	Gen H	Gen I	NGT
Marginal Offer Price revenue	£10,750	£0	£64,500	£26,875	£5,375	£0	£0	£0	£0	-£107,500
Imbalance Cost	-£7,014	£0	-£54,411	-£17,535	-£3,507	£0	£0	£0	-£12,537	£0
RCRC	£7,169	£7,257	£18,385	£12,315	£2,375	£13,195	£5,278	£8,797	£20,232	£0
Increased BSUOS	-£8,112	-£8,212	-£20,803	-£13,935	-£2,688	-£14,931	-£5,972	-£9,954	-£22,894	£107,500
Net Position	**£2,792.96**	**-£954.61**	**£7,670.96**	**£7,720.05**	**£1,555.58**	**-£1,735.66**	**-£694.26**	**-£1,157.11**	**-£15,197.91**	**£0.00**