MODIFICATION PROPOSAL P138 'CONTINGENCY ARRANGEMENTS IN RELATION TO THE IMPLEMENTATION OF DEMAND CONTROL MEASURES PURSUANT TO GRID CODE OC6'

ASSESSMENT CONSULTATION DOCUMENT

INTRODUCTION

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.

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. The Panel also agreed that the assessment should be undertaken by members of the Pricing Issues Standing Modification Group (PSMG), supported by members of the Volume Allocation Standing Modification Group (VASMG) and Licensed Distribution System Operators (LDSOs).

P138 aims to bring certain aspects of the Demand Control process within the provisions of the Balancing and Settlement Code (the Code) as there are currently no provisions in the Code that relate to the impact of Demand Control measures as defined by the Grid Code OC6

To date, the PSMG have met five times to consider P138, on 15 September 2003, 2, 10 and 23 October 2003 and 6 November 2003. The PSMG have undertaken an impact assessment. This consultation document contains a summary of the Assessment Procedure and deliberations of the PSMG to date in respect of P138.

Note that the Impact Assessment is currently taking place. A supplementary to this consultation will be provided if the results of the Impact Assessment are received prior to the end of the consultation period for consideration as part of the consultation.

It should also be noted that the PSMG have considered various options in relation to the solution for P138 that could be considered to be potential options to form an alternative, as set out in this document and touched on by some consultation questions. However, the PSMG has not concluded on any of these options at this time.

CONSULTATION LOGISTICS

A description of the mechanism proposed for P138, plus the Requirements Specifications for P138 is provided in support of this consultation (to provide detail supplementary to that in this consultation and is provided for information only[1]).

Please send your responses, in the proforma provided, by:

17:00 on Monday 24 November 2003

to Modifications@elexon.co.uk and please entitle your email **'P138 Assessment Consultation'**. Please note that any responses received after the deadline may not be considered by the Modification Group (due to the tight timescales for the PSMG consideration of the responses).

Any queries on the content of the consultation pro-forma should be addressed to Katie Key on 020 7380 4377, email address katie-ann.key@elexon.co.uk.

P138 PSMG DELIBERATIONS

In order to give effect to the Proposed Modification, the PSMG considered that there were four key requirements:

- To establish a price signal to the System Operator (SO) and consequently that the SO should be liable for costs arising from Demand Control;
- To enable these costs to be reflected in imbalance prices to retain and enhance the incentives to balance;
- To ensure that Supplier's imbalance volumes are corrected following the reduction in Metered Volumes resulting from Demand Control; and
- To adequately recompense Suppliers for the costs incurred in contracting for energy that is not used by their customers as a direct result of Demand Control.

Given these requirements, the PSMG concluded that Demand Control actions should be treated as deemed Acceptances of deemed offers.

In order to quantify these Acceptances, the following elements were considered by the PSMG:

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

[1] For information, the description of the mechanism provided in this consultation should be sufficient to enable responses to be made in respect of this consultation, the Requirements Specification is provided solely to provide more detail for those Parties that are interested.

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. 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 may 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 commensurate with 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'). 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 fall within 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 a Demand Control Settlement Period.

Scope

The scope of the arrangements should cover demand takers in a GSP Group (with some exceptions), i.e. all Supplier Balancing Mechanism (BM) Units which are importing when the Deemed Demand 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 these 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 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, therefore, discriminate against Embedded Generation (if included, exports would be incorrectly reduced).

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

Demand Control Offer Price

The appropriate price for Demand Control (Demand Control Offer Price) formed a key consideration of the PSMG. The PSMG noted that, under the current regime, there was 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 spill were increased), or a decrement of System Buy Price (SBP) (if shortfall were reduced). The treatment of Demand Control as a deemed Acceptance of a deemed Offer would remove this imbalance cash-flow. The Proposed Modification stated that the Demand Control Offer Price should be a marginal price as this would reflect the cost of the next action taken within the Balancing Mechanism had actions other than Demand Control been available. The PSMG concluded that the most appropriate marginal price was the highest priced Accepted Offer with a volume greater that 1 MW (effectively removing those Offers that would be De-minimus 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.

Defaults

Where there is no marginal offer price to use, the PSMG considered that, the defaults should mimic those used for imbalance pricing. Hence, in the absence of a marginal offer price, 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 Net Imbalance Volume i.e. the same value that the Market Index Price defaults to when it is zero.

Price Signals

Since the payment for the deemed Demand Control Offer (at a marginal price) would feed through to the imbalance price for the Demand Control Settlement Period, the imbalance price for that Demand Control Settlement Period would then also tend toward a marginal price. Hence, any of those Parties that were short (and therefore could be said to causing the Demand Control) would 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 the likelihood of a high SBP during periods of system stress.

Other Demand Control Offer Price Options

The PSMG also considered some other options for the Demand Control Offer Price, which if pursued, could form an alternate 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 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 as 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 marginal offer price, 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 at this stage no alternate modification has been developed.

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 (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. This overall volume would then need to be allocated to the relevant Supplier BM Units in the affected GSP Group. This would be calculated using latest available BM Unit metered volumes to establish the proportion of demand each BM Unit in the GSP Group used. 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 the Non-Delivery Rule would need to be relaxed for these deemed acceptances to mitigate the effect of the Non-Delivery Rules. 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 and entered into the Bid-Offer Stack.

Reporting

In the first instance, the PSMG considered that there should be prompt reporting. Given the difficulty of identifying the prices and volumes fore 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 Offer Acceptance with the highest price which is greater than 1 MW in energy and that would not be tagged out by the CADL taken 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. Settlement Reporting would then report as normal.

Implementation Approach

The PSMG considered that there should be minimal system impact from this proposal and that ad-hoc calculations and estimates would suffice. In particular, the PSMG considered that Workaround 18, which allows Parties to have the data concerning BM Unit Acceptances corrected, could form the basis of this proposal.

Other assessment issues

The following additional assessment issues have been identified by the PSMG from the Terms of Reference for P138

Whether the Modification Proposal is within the vires the BSC

The PSMG considered whether Modification P138 was within the vires of the BSC 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 agreed that the reason that these Modifications were not implemented by the Authority 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 BSC does however mention Demand Control and is a commercial document hence it was deemed the most suitable place for contingency measures relating to 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 proposal was believed to be a legitimate one to be considered under the auspices of the BSC.

Definition of Marginal Price

Aside from the Definition of marginal price 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 System Buy Price 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 chosen for the Demand Control Offer Price 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 in the NIV 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 System Buy Price would be calculated as per normal.

  The PSMG believed that there may 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.

Impact on the Grid Code

The P138 proposal noted that there may be a requirement to amend OC6 of the Grid Code. However, the particular solution to P138 proposed by the PSMG does not require any explicit changes to the Grid Code for it to be effective.

Impact on Manifest Errors

The PSMG agreed that since the proposed solution established deemed Offers according to rules set out in the BSC, any errors would be disputable under the current disputes process but would not impact the Manifest Error process.

Interaction with other Modifications

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

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-minimus 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 only those that would be de-minimus tagged.

ASSESSMENT OF P138 AGAINST THE APPLICABLE BSC OBJECTIVES

(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 to the SO, that the SO's behaviour would be optimal 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 economic rational 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 not to use 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 period 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 increase it towards the marginal 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 price, the actual marginal offer price would constitute a windfall gain for those subject to Demand Control. On this basis, an administered deemed 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.

(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 their contract price fully re-imbursed through the resultant change in its imbalance position. 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 Balancing Services Use of System (BSUoS) charges following Demand Control would increase under P138. 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 marginal offer price. This would lead to parties not directly impacted by the Demand Control action, effectively subsidising the payment to Suppliers whose volume were affected.

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

The PSMG recognised that the 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 the need for Demand Control being such a rare and unpredictable event.

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 within 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 BSUoS.

The results of the analysis are largely influenced by the assumptions that are made. 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 National Grid have issued a Demand Reduction Imminent (DRI), High Risk Of Demand Reduction (HRDR), or Notification of Insufficient System Margin (NISM) warnings.

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:

- System Buy Price calculated without the deemed Demand Control Offer (as it is now)
- System Buy Price calculated with the deemed Demand Control Offer (under P138)
- Market 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 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 is the 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
Beer Fund	£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
Beer Fund	£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
Beer Fund	£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
Beer Fund	£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
Beer Fund	£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
Beer Fund	£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
Beer Fund	£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
Beer Fund	£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**