Constraint Costing Methodology (Locational BSUoS)

1. Introduction

The System Operator (SO) performs a number of activities in managing the transmission system. These involve the procurement of balancing services to resolve issues such as constraint management and residual energy balancing. In line with its licence obligation to act economically and efficiently the SO may take a single action to resolve a number of functions if it deems this single action to be the least cost solution.

The following methodology set outs how the costs that the SO incurs in managing transmission constraints are calculated. Included within this is the mechanism by which the costs of an action taken to resolve both constraints and another issue are apportioned.

The methodology employed by the SO to allocate costs is utilised by National Grid in its internal cost management functions to track expenditure

The philosophy behind this constraint costing methodology is to consider what actions the SO would have taken if the constraint had not been active. To that end the methodology considers the following aspects in determining the direct and opportunity costs that the SO incurs in managing a constraint, namely,

- The price of the first order constraint action in comparison to the price that could be achieved from a BMU in a non constrained part of the network.
- Whether the action brought the market closer to, or further from, energy balance and the cost of recovering that imbalance position.
- The services that were sterilised as a consequence of the constraint

In the event that this cost is incurred by resolving a constraint across a derogated non complaint boundary, the methodology sets out which types of constraint costs would be charged to the locational element of BSUoS. It also sets out how the costs would be apportioned between those incurred due to the fact that the boundary is non compliant and the costs that would have been incurred under a compliant boundary.

2. The Energy Reference Price

This methodology compares the price that has been achieved for a particular buy or sell action associated with management of a constraint with that which could have been achieved if the volume of energy had been bought or sold using an appropriate measure for the price of energy in the Balancing Mechanism in that half hour. Effectively it compares the price of the action against what could have been achieved in the notional "National Hub" price.

For example, in a situation where bids are taken for a constraint in a long market[1] these bids may be the only actions taken. However, these bids may be taken out of strict cost order relative to the price that could be achieved procuring services to resolve only the energy imbalance on the system. Therefore, the cost to the SO is the incremental cost of taking the constraint action beyond that which would have taken in the absence of the constraint.

Determining the differential in prices is accomplished by the calculation of an "Energy Reference Price" (ERP).This is derived by taking a volume weighted average of all submitted Bids or Offers required to meet market length as measured by the "Net Imbalance Volume" (NIV) in a given Settlement Period.

[1] Generation supplied by the market exceeds demand offtake.

As well as the price of these submitted bids and offers this calculation also looks at the accessibility of the energy by taking into account the MEL and SEL of the BMU on which the bids and offers are submitted.

In settlement periods where the market is short (NIV is positive)

ERPj (Short Market)

$$\frac{\sum_{0}^{NIV}\left(MAX\left\{0, MIN\left[\left(QBO_{kij} + \left\{\begin{matrix} MEL_{ij}^{FPN>=0} \\ SIL_{ij}^{FPN<0}\end{matrix}\right\} - FPN_{ij} - \sum_{1}^{k,k>0} QBO_{kij}\right), QBO_{kij}\right]\right\} * PO_{kij}\right)}{\sum_{0}^{NIV} MAX\left\{0, MIN\left[\left(QBO_{kij} + \left\{\begin{matrix} MEL_{ij}^{FPN>=0} \\ SIL_{ij}^{FPN<0}\end{matrix}\right\} - FPN_{ij} - \sum_{1}^{k,k>0} QBO_{kij}\right), QBO_{kij}\right]\right\}}$$

(Sum of Feasible Offer Volume between FPN and MEL (SIL where FPN<0) * Price divided by Net Imbalance Volume)

In settlement periods where the market is long (NIV is negative)

ERPj Long Market

$$\frac{\sum_{0}^{NIV}\left(MAX\left\{0, MIN\left[\left(QBO_{kij} + \left\{\begin{matrix} 0^{FPN>0} \\ MIL_{ij}^{FPN<=0}\end{matrix}\right\} MIL_{ij} - FPNij - \sum_{1}^{k,k<0} QBO_{kij}\right), QBO_{kij}\right]\right\} * PB_{kij}\right)}{\sum_{0}^{NIV} MAX\left\{0, MIN\left[\left(QBOk_{ij} + \left\{\begin{matrix} 0^{FPN>0} \\ MIL_{ij}^{FPN<=0}\end{matrix}\right\} - FPN_{ij} - \sum_{1}^{k,k<0} QBO_{kij}\right), QBO_{kij}\right]\right\}}$$

(Sum of feasible Bid volume between FPN and MIL * Price divided by NIV; MIL assumed = zero where FPN>0)

Therefore in instances where a constraint management action also resolves market length the energy cost of the constraint to the SO is set out in equation 1

Equation 1 cost of constraint action used to resolve market length

Cost = Volume of Action (MWh) * ((Price of action (£/MWh) – ERP (£/MWh))

3. Replacement Energy

Where the volume of actions taken to manage constraints is in excess of or in the opposite direction to the length of the market (NIV) then a volume of actions must also be taken to bring generation and demand back in to equilibrium. The actions that are needed to rebalance generation and demand are termed “Replacement Actions”[2]

[2] Due to them replacing the energy taken off the system, in the case of Bids

The energy required to replace that lost through management of a constraint situation would be managed at a notional "National Hub" point which would be located outside of the constraint zone.

This methodology again uses the "Energy Reference Price" as the cost of energy at that point. This means that the relevant equation is unchanged:

Equation 2 : Cost of a Constraint Action

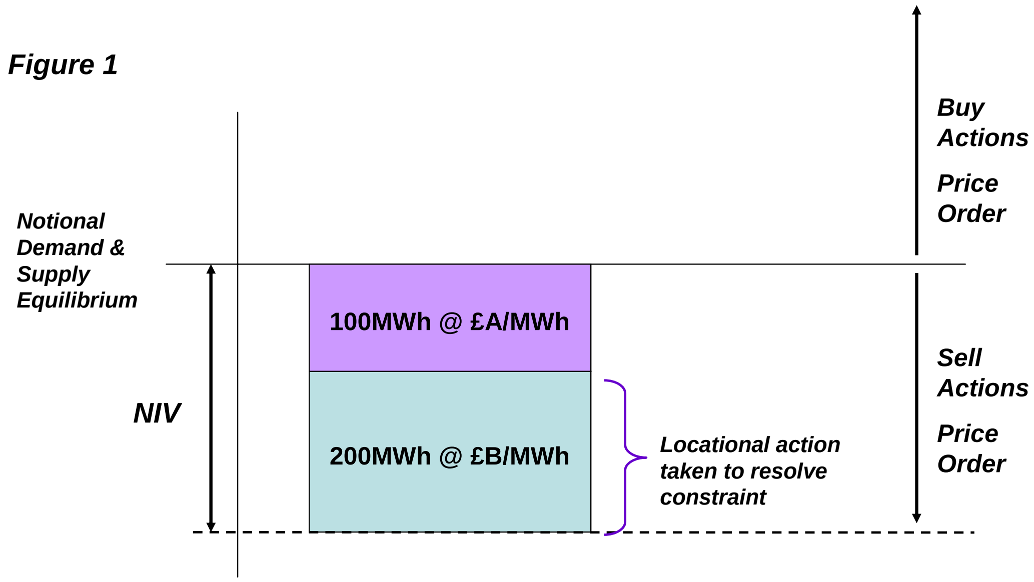
Cost = Volume of Action (MWh) * ((Price of action (£/MWh) – ERP (£/MWh))

However, in this instance the ERP value will reflect the value of resolving the increased level of energy disequilibrium that has been caused by the need to take the constraint management action. The mechanics of this replacement energy methodology are best explained through examples. The examples in this methodology have concentrated on export constraints as the only current derogated non compliant boundary.

Example 1: Taking Bids to resolve an export constraint in a long market (NIV is negative)

In this scenario the SO would take a sell action to reduce the output behind the export - constrained boundary. This would also have the effect of reducing the overall amount of energy being injected onto the transmission system. As the market started from a position of excess generation this has also brought the level of generation and demand back in to line i.e the same Bids have resolved both the constraint and NIV. This is demonstrated in figure 1.

Figure 1: Export constraints in a long market.

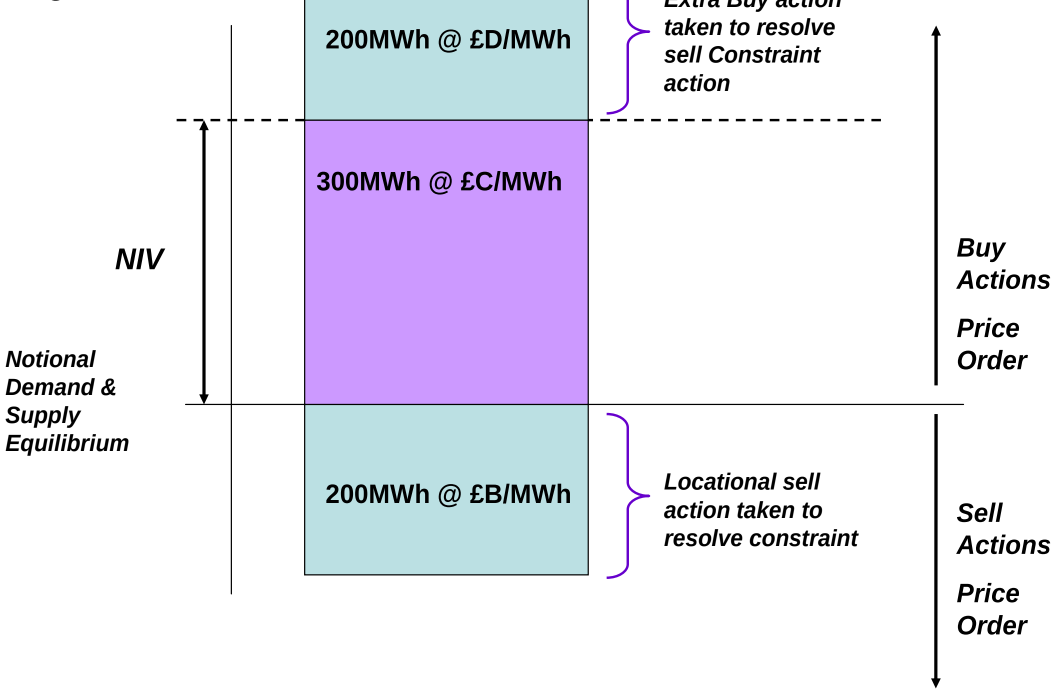


Example 2: Taking Bids to resolve an export constraint in a short market (NIV is positive)

In this scenario the market was short. The quantity of energy contracted to be injected on to the system was less than the level of electricity demanded by customers. The export constraint would require the SO to reduce the amount of electricity being generated a particular node on the system. This would reduce the total system infeed and so exacerbate the level of demand supply disequilibrium in this settlement period.

As a consequence the SO would need to take a greater number of buy actions to balance the system than it would need to in the absence of a constrained boundary. This is demonstrated in Figure 2

Figure 2

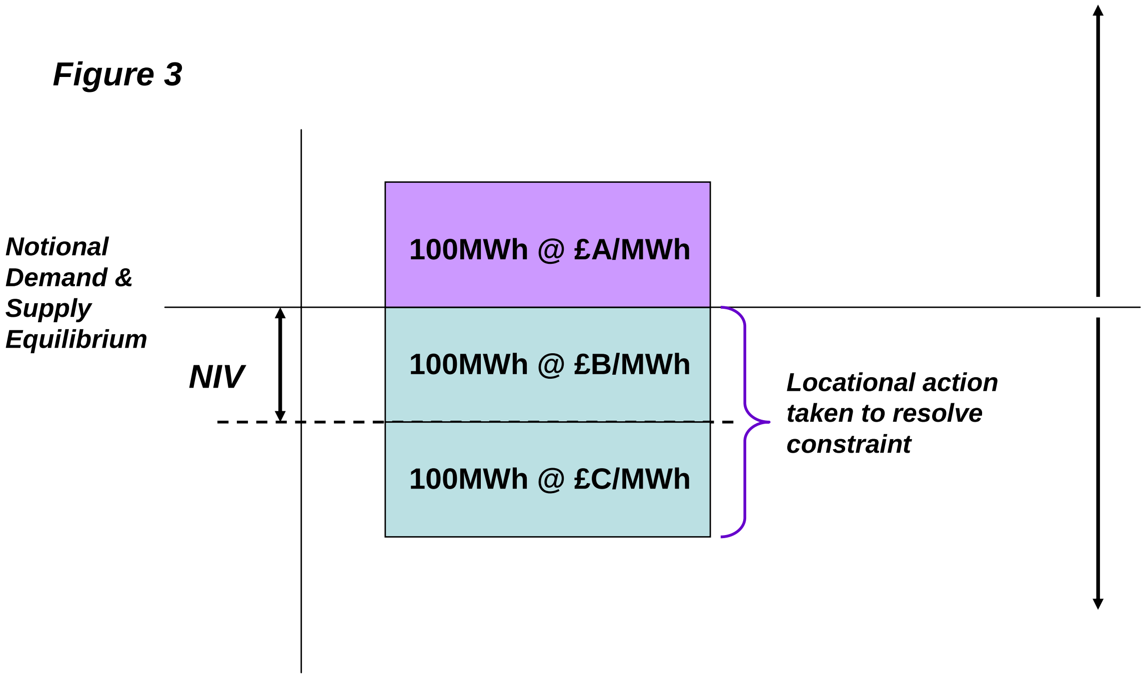


These buy actions would be taken outside of the constrained boundary. Therefore the direct cost of the constraint in this scenario would reflect the cost of replacing the energy. As noted the proxy for the price of energy in each half hour is the ERP. Therefore the direct cost of managing the constraint in this period is reflective of the cost of selling the energy at price B in the constrained location and buying it back at the ERP at the notional National Hub point.

Example 3: Taking Bids to resolve an export constraint in a long market (NIV is negative) in circumstances where the volume of the constrained bid is greater than the length of the market (NIV)

In this scenario the market is long. The bid taken to manage the constraint also resolves the energy imbalance on the system. However the volume of the constraint is such that reducing that level of energy from this system goes further than resolving the imbalance and creates a short fall of electricity to meet demand. Consequentially the SO needs to procure more energy outside of the constrained area to resolve the short fall that has been created by taking actions to manage the constraint. This is represented in figure 3

Figure 3



In this scenario the direct costs of the constraint action needs to be assessed in two ways. It could be argued that 100MWh of the 200MWh constraint action also resolved the energy imbalance on the system. Therefore the cost to the industry is dependent on the price that had been achieved when undertaking this constraint action relative to the price that the SO could have achieved if only selling this energy to resolve the energy imbalance of the system.

The cost of the second 100 MWh of actions would reflect the fact that the energy removed from the system by such an action needs to be replaced in order for the system to balance generation and demand. This methodology uses the ERP to represent the notional hub price of energy in each half hour.

Therefore the cost of the constraint will be the difference between the ERP and the price achieved on the sell product utilised to manage the constraint.

4. Proportion of Direct Costs Attributable to Derogated Boundary Non Compliance (Proportion of costs charged through Locational BSUoS)

The volume of constraints incurred due to boundary non compliance is set out in Appendix 3 of the Locational BSUoS consultation released on 13th March 09*.* That methodology determines that the minimum of the capability deficit, or the volume of constraints incurred on the boundary in any half hour, are to be charged on a locational basis.

If more bids are taken against the boundary than are deemed due to the boundary being non compliance then it must be determined which actions, and there associated costs, are included within the locational BSUoS charge.

The philosophy behind this is framed by posing the following question. “If the boundary was compliant which constraint costs would not occur?” The SO takes actions in an efficient order and so will undertake the least cost solution to resolve an issue. Therefore if the boundary was compliant the SO would avoid the need to take a proportion of actions and these would be the relatively more expensive actions.

The SO utilises a number of different products to resolve constraints on the transmission system. These can be considered as single or paired action products.

A single action is a bid, offer, buy trade or sell trade. Effectively this product resolves the issue at the location but does not accommodate any energy replacement that may be required as a consequence of that action.

A paired action is one where, implicitly, the energy disequilibrium element of the action is also accommodated. Examples of this include capped PN contracts and inter-trips.

PN contracts obligate a unit to generate at a level below its commercial position. The contract structure does not trade energy but provides compensation for generating at that level. Therefore the generator must manage the resolution of its energy position unilaterally. This may be accomplished by shifting output onto another BMU within the portfolio or procuring that energy in the open market. In both cases the participant effectively provides the replacement energy. The PN contract price structure effectively works on a price spread assessment. The cost in terms of £/MWh stopped from physically flowing onto the system are assessed against offer price, bid price spread in the market in each settlement period.

Conceptually an inter trip can also be considered a “paired action”. An Inter trip increases the pre fault network capability at the boundary. It does not require a counter action to replace the energy disequilibrium in another part of the system. The assessment of the efficiency of an inter trip is assessed against offer price, bid price spread in the market for each MW of pre fault capacity it accommodates.

Therefore when assessing the merit order of actions taken to manage constraints the price of Buy and Sell actions cannot be taken in isolation but in terms of how they could accommodate energy replacement. Therefore when assessing the merit order of “single actions” is necessary to create a price spread based on the prevailing ERP.

For example a sell action price will be converted into a spread price of ERP – sell price. A buy action price will be converted into a spread price of buy price - ERP

The resultant prices along with the prices associated with “paired actions” will be ranked in price order as demonstrated in figure 4.

Figure 4

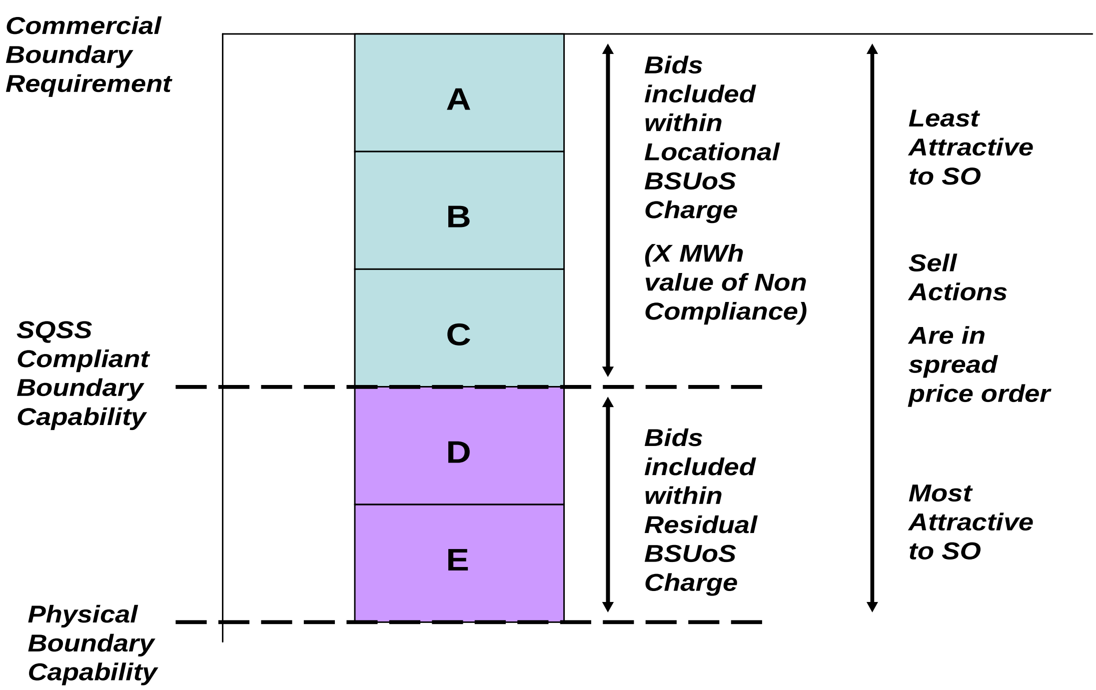


Figure 4 demonstrates that the costs associated with constraint actions A, B and C are charged through the locational element.

5. The Costs of Replacing Required Generation Margin

Balancing Generation and Demand requires the maintenance of reserve of energy that is available in operational timescales. This requires that the sum of the Maximum Export Limits (MEL) of accessible generation is more than a certain level above the expected demand and that the sum of Stable Export Limits (SEL) is less than a certain level below demand.

Positive reserve, which is the difference between sum of MELs and demand, is called Margin. The principles apply equally to negative reserve (footroom or downwards regulation) albeit with the opposite signs imposed.

When a unit's output is reduced to manage a constraint it can be assumed that the output level that unit is reduced to is the highest permissible level that the transmission system can support at that time. As such this imposes a maximum transmission export limit on the unit which is lower than the unit's technical maximum. The difference between the level of permissible export to the system and the maximum output of the unit is therefore now not available to the SO. In such circumstances the sum of available MEL is also reduced. This reduction in available maximum generation due to a constraint is termed "Sterilised Headroom".

In certain circumstances the headroom that is sterilised behind a constraint is of sufficient volume that it leads to a deficit in the level required by the SO to secure the transmission system to the require standards.

When actions to manage constraints reduce the level of available reserve below the required level, the SO will buy services to fill the deficit. This predominantly accomplished through the synchronisation of additional generation units.

The volume and cost of reserve procured by the SO, up to the volume of headroom sterilised by constraint management activity, is deemed to be necessary due to the constraint management activity.

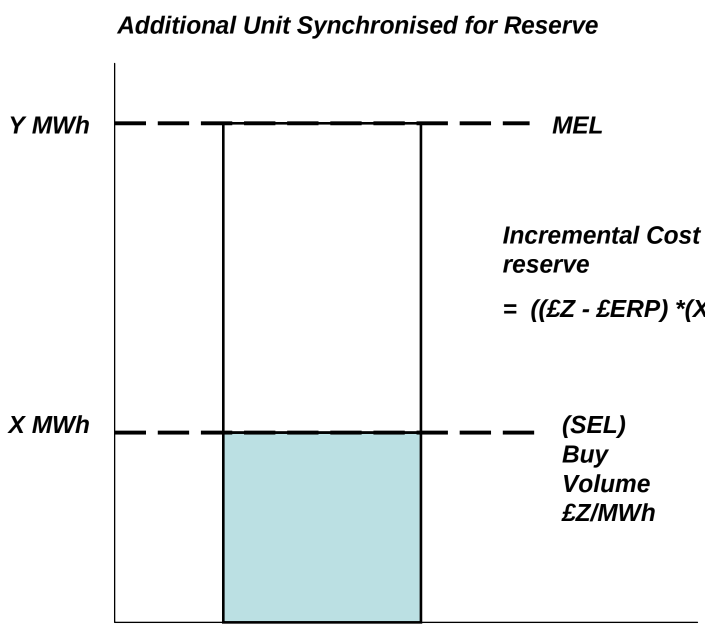
In circumstances where there is more than one generation BMU behind an export constrained boundary a bid taken to manage the constraint on one of those units infers that no other buy actions can be taken on any of these units. If no buy actions can be taken on any of these units it implicitly assumes that such energy is inaccessible and so the head room is sterilised[3].

This total level of headroom sterilised is then compared to the volume of reserve procured by synchronising additional units in the rest of the system. The smaller of the volume of headroom sterilised or the volume of reserve created is determined as the volume of reserve creation that can be attributed to the cost of resolving the constrained boundary.

[3] This excludes units which were not synchronised by the market, or headroom on PN capping contracts. includes those that have been desynchronised to manage the constraint

The cost of creating additional reserve is demonstrated in figure 5

Figure 5



The value of reserve procured in this example is Y MWh.

The cost of reserve replacement of all machines synchronised for margin, and whose total volume of reserve created is subsequently identified as replacing sterilised headroom, are converted in to a £/MW of MEL value.

The derivation of this value takes in to account the incremental cost of creating this reserve in that it is the volume of energy procured to bring the unit to SEL times the incremental (or out of merit) price paid for this volume divided by the increase in synchronised MEL resulting from this unit.

Therefore the £/MWh incremental cost of creating reserve is

((£Z - £ERP) * X MWh (SEL)) / Y MWh (vol of capacity) = £Q/MWh reserve costs

Note – The cost of creating reserve is not the cost of the buy action but the incremental cost of the buy action above the Energy Reference Price (ERP). This represents the replacement of system bids or alternative offers. This also means that for the purposes of constraint costing that the cost of replacement energy, as represented by ERP, is not included twice in the constraint cost.

This value is then taken as a volume weighted average across all additional machines wholly used to replace sterilised headroom to produce a Constraint Margin Reference Price per period.

Each MW of sterilised headroom is then multiplied by this value.

6. Proportion of Sterilised Headroom Costs Allocated to Locational BSUoS

Should the cost associated with replacing headroom, sterilised due to boundary non compliance, be included within the Locational BSUoS charge.? The GBSQSS determination of required capacity considers both the delivery of energy and also the ability of units not operating at full load to offer that capacity to the SO as a balancing service. Therefore a deficit in required capacity not only prevents energy sold in the energy market from physically reaching its customer but also restricts the SO from accessing balancing services in that zone.

However is it appropriate that the cost of sterilised reserve should be included within the locational charge? With an appropriate signal, generation BMU located behind a non compliant boundary will be able to make informed decisions whether to absorb the locational BSUoS charge or amend their generation load level accordingly.

Generators are less able to initiate changes in levels of reserve holding within and outside of the constrained boundary. However the replacement of sterilised headroom is a genuine cost that the SO incurs when managing transmission constraints.

We would welcome participant’s views on whether the costs of replacing sterilised headroom should be included within the locational BSUoS charging element.

In the event that it was deemed appropriate to allocate the costs associated with replacing sterilised headroom we believe it would be undertaken in the following way.

The level of headroom costs charged on a locational basis will be applied in the same proportion as that of the volume of energy actions deemed to have been incurred due to a boundary being non compliant.

Assume that the SO is required to taken 200MWh of actions to resolve a constraint against a non compliant boundary. The methodology determines that 150 MWh of actions are taken to due to boundary non compliance.

If we assume that 400 MWh of headroom has been sterilised against the same boundary

Under the proposed methodology 150/200 * 400MWh of sterilised headroom costs would be charged through locational BSUoS.

7. Post Fault Actions

The SO can manage a constraint through pre emptive activity defined as pre fault actions or manage constraints after the fact know as post fault actions. The most visible example of a post fault action is the firing of an inter trip.

The question that has arisen is whether the costs of these post fault actions, associated with managing constraints on a non compliant boundary, should allocated on a locational basis. The SOs initial thoughts are that it may not be appropriate, or indeed practical, to allocate these costs to the locational element of the BSUoS charge.

8. Locational BSUoS with Multiple Derogated Non-Compliant Boundaries

Currently, only one derogated non-compliant boundary exists on the GB transmission system: the B6 (Cheviot boundary). In future it is possible that additional boundaries may be non-compliant and as a result have derogations granted.

Under such a scenario a generator may be connected behind more than one non-compliant boundary and it is necessary to determine how Locational BSUoS would be calculated in these circumstances.

The high level principles for calculating the applicable Locational BSUoS charges for generators connected behind multiple derogated non-compliant boundaries are set out below.

i) The non-compliant volume of constraint actions, together with the spread cost of those actions and consequential balancing actions, must be discretely calculated for each non-compliant boundary, for each Settlement Period,

ii) Generators will pay a cost proportional to the costs of resolving all derogated non-compliant boundaries to which their output contributes.

iii) In recognition of the efficiency arising from constraint actions that contribute to the resolution of more than one boundary, all boundary costs will be scaled to reflect this efficiency.

iv) Locational BSUoS will be calculated as the appropriate, scaled boundary costs, apportioned to generators in proportion to their output in each Settlement Period.

Example of Locational BSUoS Methodology with multiple derogated non compliant boundaries

The way in which the locational BSUoS operates across multiple derogated non compliant boundaries is best described by an example.

- Consider a network with 3 non-compliant boundaries: B1, B2 and B3, that divide the network into 4 zones:
  Zone 1 (network north of boundary B1)
  Zone 2 (network between boundaries B1 and B2)
  Zone 3 (network between boundaries B2 and B3)
  Zone 4 (rest of network south of boundary B3)

- Assume boundaries B1, B2 and B3 are deficient from compliant capacity by 300MW, 500MW, 1800MW respectively.

- The operational limits experienced for a given period of real time operation for boundaries B1, B2 and B3 are 1000MW, 1400MW and 16000MW respectively.

- Assume for a given settlement period, unconstrained generation and demand in zones 1,2 and 3 are as follows:

Generation:

Zone 1:	Gen A	= 300MW
	Gen B	= 400MW
	Gen C	= 350MW
	Gen D	= 450MW
	Gen E	= 500MW
	Total	**= 2000MW**,

Zone 2:	Gen F	=	200MW
	Gen G	=	300MW
	Gen H	=	300MW
	Gen I	=	450MW
	Gen J	=	400MW
	Gen K	=	300MW
	Gen L	=	450MW
	Gen M	=	200MW
	Gen N	=	400MW
	Total	**=**	**3000MW**

Zone 3:	Gen O	=	200MW
	Gen P	=	200MW
	Gen Q	=	250MW
	Gen R	=	250MW
	Gen S	=	400MW
	Gen T	=	300MW
	Gen U	=	450MW
	Gen V	=	600MW
	Gen W	=	600MW
	Gen X	=	400MW
	Gen Y	=	150MW
	Gen Z	=	200MW
	Total	**=**	**4000MW**

Demand:

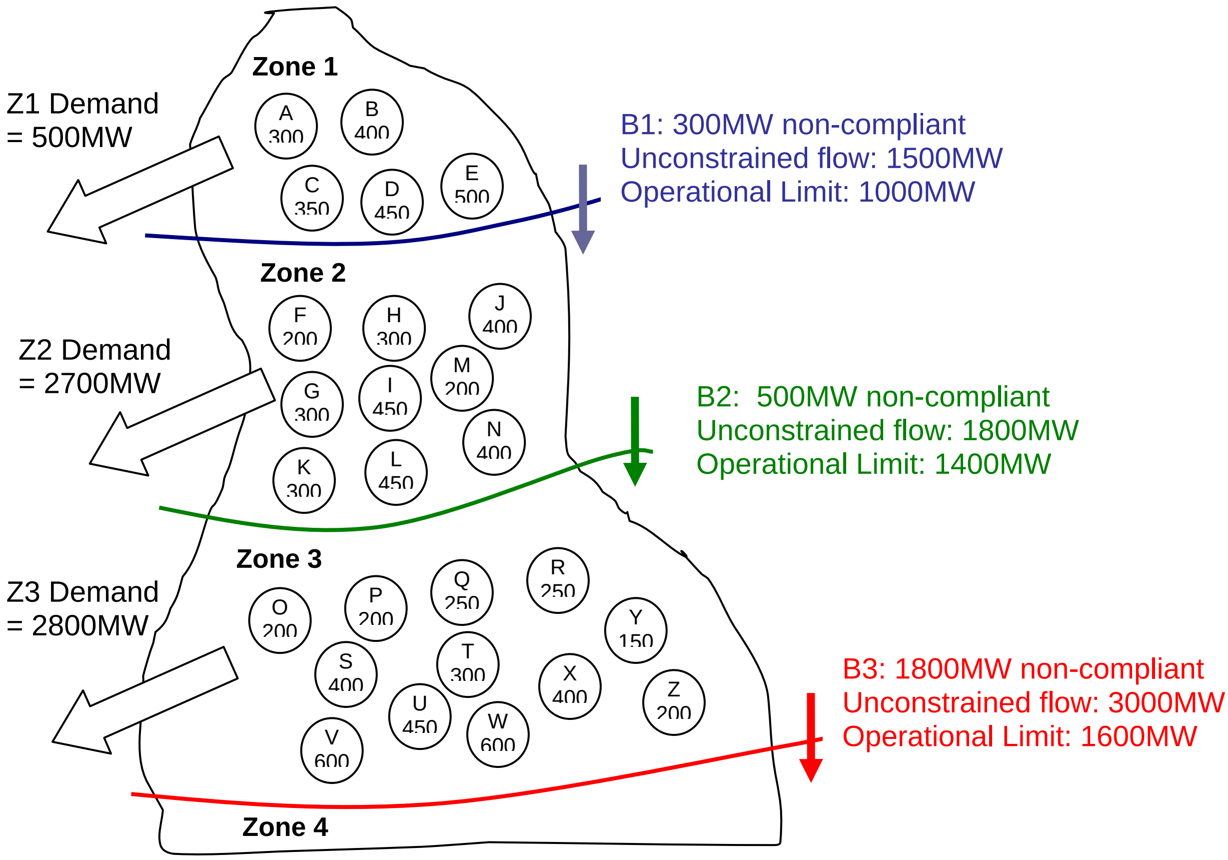
Zone 1 = 500MW,
Zone 2 = 2700MW
Zone 3 = 2800MW.

- The resultant unconstrained energy flows across boundaries B1, B2 and B3 are 1500MW, 1800MW and 3000MW respectively, calculated as follow:

B1 flow	=	Net Export from Zone 1
	=	Gen Zone 1 – Demand Zone 1
	=	2000 – 500
	=	1500MW

B2 flow	=	Net Export from Zone 1 + Net Export from Zone 2
	=	Net Export from Zone 1 + Gen Zone 2– Demand Zone 2
	=	1500MW + 3000MW – 2700MW
	=	1800MW

B3 flow	=	Net Export from Zone 2 + Net Export from Zone 3
	=	Net Export from Zone 2 + Gen Zone 3– Demand Zone 3
	=	1800 + 4000 - 2800
	=	3000MW



- Assume the bids and consequential replacement actions taken to resolve the operational constraints result in the spread costs as follows:

  100MW bids on generator A at spread cost of £50/MWh = £2500
  200MW bids on generator B at spread cost of £30/MWh = £3000
  200MW bids on generator E at spread cost of £20/MWh = £2000
  200MW bids on generator L at spread cost of £20/MWh = £2000
  200MW bids on generator S at spread cost of £10/MWh = £1000
  100MW bids on generator T at spread cost of £15/MWh = £750
  200MW bids on generator U at spread cost of £15/MWh = £1500
  200MW bids on generator X at spread cost of £25/MWh = £2500

- Individual constraint volumes and costs are as follows:

  B3:

  Operational constraint volume of B3 is 3000-1600 = 1400MW
  Flow - limit

  In cost order, this was achieved by:

  200MW bids on generator S at spread cost of £10/MWh = £1000
  100MW bids on generator T at spread cost of £15/MWh = £750
  200MW bids on generator U at spread cost of £15/MWh = £1500
  200MW bids on generator E at spread cost of £20/MWh = £2000
  200MW bids on generator L at spread cost of £20/MWh = £2000
  200MW bids on generator X at spread cost of £25/MWh = £2500
  200MW bids on generator B at spread cost of £30/MWh = £3000
  100MW bids on generator A at spread cost of £50/MWh = £2500

  Non compliant volume of B3 = 1400 (<1800)
  (max non-compliant volume)

  i.e. all of above are non-compliant actions for B3

  So non-compliant cost of B3 = £15250

  B2:

  Operational constraint volume of B3 is 1800-1400 = 400MW
  Flow - limit

  In cost order, this was achieved by:

  200MW bids on generator E at spread cost of £20/MWh = £2000
  200MW bids on generator L at spread cost of £20/MWh = £2000

  Non compliant volume of B2 = 400 (<500)
  (max non-compliant volume)

  i.e. all of above are non-compliant actions for B2

  So non-compliant cost of B2 = £4000

  B1:

  Operational constraint volume of B1 is 1500-1000 = 500MW
  Flow - limit

  In cost order, this was achieved by:

  200MW bids on generator E at spread cost of £20/MWh = £2000
  200MW bids on generator B at spread cost of £30/MWh = £3000
  100MW bids on generator A at spread cost of £50/MWh = £2500

  Non compliant volume of B1 = 300
  (max non-compliant volume)

  i.e. 300MW of above 500MW actions are non-compliant actions for B1

  Non-compliant actions should be most expensive actions, which are

100MW bids on generator A at spread cost of £50/MWh = £2500
200MW bids on generator B at spread cost of £30/MWh = £3000

So non-compliant cost of B1 = £5500

- Due to nesting of constraints, some constraint actions serve to solve more than one compliance issue (each action is only taken once, so actual cost requires duplicates attributed to multiple constraints removed; struck out below):

B1:	100MW bids on generator A at spread cost of	£50/MWh	= £2500
	200MW bids on generator B at spread cost of	£30/MWh	= £3000
B2:	200MW bids on generator E at spread cost of	£20/MWh	= £2000
	200MW bids on generator L at spread cost of	£20/MWh	= £2000
B3:	200MW bids on generator S at spread cost of	£10/MWh	= £1000
	100MW bids on generator T at spread cost of	£15/MWh	= £750
	200MW bids on generator U at spread cost of	£15/MWh	= £1500
	~~200MW bids on generator E at spread cost of~~	~~£20/MWh~~	~~= £2000~~
	~~200MW bids on generator L at spread cost of~~	~~£20/MWh~~	~~= £2000~~
	200MW bids on generator X at spread cost of	£25/MWh	= £2500
	~~200MW bids on generator B at spread cost of~~	~~£30/MWh~~	~~= £3000~~
	~~100MW bids on generator A at spread cost of~~	~~£50/MWh~~	~~= £2500~~

Total non-compliance actual spend = £15250

Please note - In this example the notional cost of resolving the B6 boundary (£15250) is the same as the total real cost of resolving all non compliant constraint volumes

- Locational BSUoS charge for each zone should be non-compliant cost of all boundaries that generation in the zone contributes to, scaled such that summated cost of all zones equals total non-compliance actual spend (£15250).

The Ratio of:

= Actual non compliant spend / (notional costs of resolving zone 1 + zone 2 + zone 3)

= £15250 / (£5500 + £4000 + £15250)

= £15250/£24750

= 0.6161

Therefore given:

The notional cost of resolving the non compliance of B1 = £5500

The notional cost of resolving the non compliance of B2 = £4000

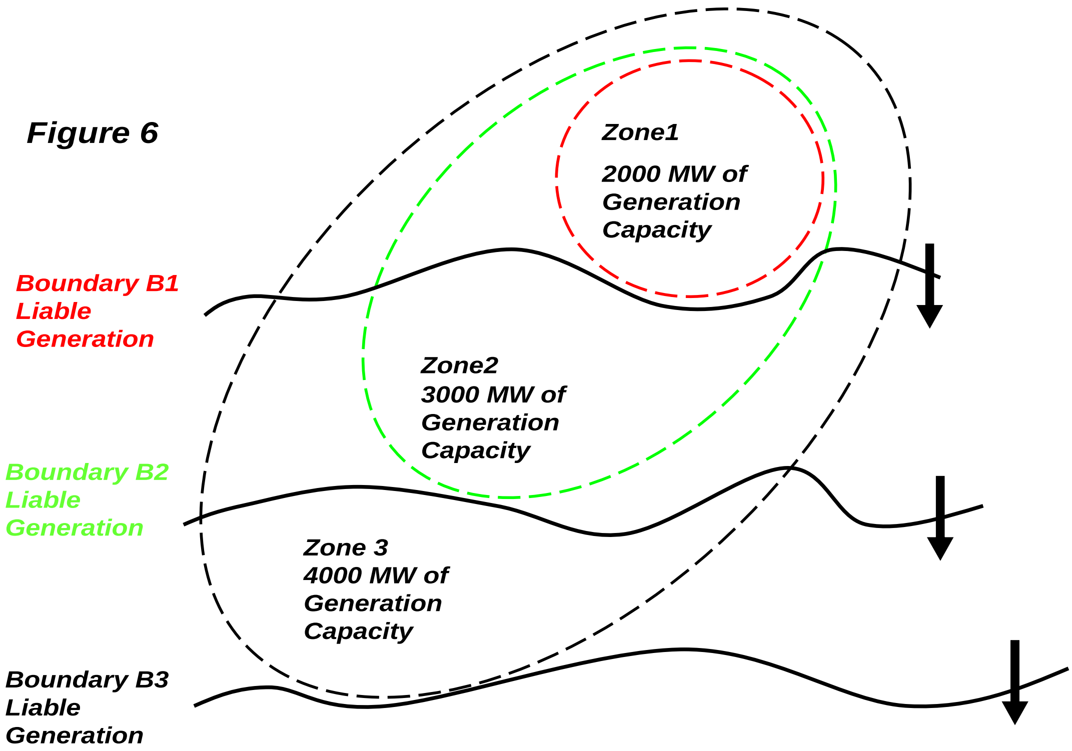
The notional cost of resolving the non compliance of B3 = £15250

Generation in Zone 1: Contributes to non compliance of Boundary B1

Generation in Zone 1 & Zone 2: Contribute to non compliance of Boundary B2

Generation in Zone 1,Zone 2 & Zone 3: Contribute to non compliance of Boundary B3

Figure 6 describes the generation that is liable for the costs of constraints incurred due to boundary non compliance at each of the boundaries in the example



Given the following notional costs and Generation Volumes

Notional Boundary Costs B1	£5,500	***Zone 1 Gen Vol MW***	2000
Notional Boundary Costs B2	£4,000	***Zone 2 Gen Vol MW***	3000
Notional Boundary Costs B3	£15,250	***Zone 3 Gen Vol MW***	4000

Generation in each zones will pay the following costs per MW of generation

A generator in Zone 1 will pay the following £/MWh output charge

(£5550/2000MW + £4000/5000MW + £15250/9000MW) * 0.6161 = **£3.23/MWh**

A generator in Zone 2 will pay the following £/MWh output charge

(£4000/5000MW + £15250/9000MW) * 0. 0.6161 = **£1.54/MWh**

A generator in Zone 3 will pay the following £/MWh output charge

(£15250/9000MW) * 0. 0.6161 = **£1.00/MWh**

Therefore the zonal charge is to be applied to generators in each zone in proportion to the generator's unconstrained output is as follows:

Zone	***Generator***	***MW Output***	***Charge (£/MWh)***	***Costs £***
Zone 1	Gen A	300	3.23	£969.43
Zone 1	Gen B	400	3.23	£1,292.57
Zone 1	Gen C	350	3.23	£1,131.00
Zone 1	Gen D	450	3.23	£1,454.14
Zone 1	Gen E	500	3.23	£1,615.71
Zone 2	Gen F	200	1.54	£307.40
Zone 2	Gen G	300	1.54	£461.09
Zone 2	Gen H	300	1.54	£461.09
Zone 2	Gen I	450	1.54	£691.64
Zone 2	Gen J	400	1.54	£614.79
Zone 2	Gen K	300	1.54	£461.09
Zone 2	Gen L	450	1.54	£691.64
Zone 2	Gen M	200	1.54	£307.40
Zone 2	Gen N	400	1.54	£614.79
Zone 3	Gen O	200	1.04	£208.81
Zone 3	Gen P	200	1.04	£208.81
Zone 3	Gen Q	250	1.04	£261.01
Zone 3	Gen R	250	1.04	£261.01
Zone 3	Gen S	400	1.04	£417.62
Zone 3	Gen T	300	1.04	£313.22
Zone 3	Gen U	450	1.04	£469.82
Zone 3	Gen V	600	1.04	£626.43
Zone 3	Gen W	600	1.04	£626.43
Zone 3	Gen X	400	1.04	£417.62
Zone 3	Gen Y	150	1.04	£156.61
Zone 3	Gen Z	200	1.04	£208.81
			Total	**£15,250.00**