Ofgem’s Initial Consultation for the Electricity Balancing Significant Code Review

A response from Wärtsilä Corporation

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1 INTRODUCTION

1.1.1 This paper has been prepared as Wärtsilä's formal response to Ofgem's Initial Consultation for the Electricity Balancing Significant Code Review ('Electricity SCR'). The publication of the Initial Consultation document coincided with the formal launch of the Electricity SCR, following a consultation on the scope and timing of the review in an Issues Paper published in November 2011.

1.1.2 Wärtsilä provided a response to the Issues Paper consultation that set out our thinking on the current arrangements from the perspective of a provider of flexible technologies in the future. To recap, our key messages were as follows:

- There is a significant need for new flexible capacity investment in the UK in the period to 2020 and beyond, given the expected decommissioning of thermal plant and the increasing penetration of intermittent generation.
- An over-reliance on CCGTs (or any single technology) to provide the flexibility required may impose unnecessary system costs. The GB market arrangements need to promote the emergence of an efficient portfolio of flexible technologies that can meet the intermittency challenge at least cost to consumers (including supply-side, demand-side, and interconnection).
- The current cash-out and reserve arrangements may not facilitate the emergence of an optimal mix of flexible technologies, in particular as:
    a) They may under-value (or not transparently reveal the value of) different flexibility products in price signals; and
    b) They are complex and unpredictable, which can act as a barrier to entry for flexibility providers, and can encourage 'internalisation' of cash-out risk within the Vertically Integrated Utilities (VIUs).
- The emergence of an efficient flexibility mix will be best facilitated via transparent market-based solutions that encourage maximum participation and efficient price discovery. Only a wider scope approach to the SCR can deliver this at least cost to GB consumers.

1.1.3 There have been a number of important developments since the publication of the Issues Paper. ACER released its final Framework Guidelines on Electricity Balancing (EBFG) in September 2012, with ENTSO-E now given the task of drafting the associated Network Code. The final Framework Guidelines require member states to undertake a number of important reforms, with the overarching objective to increase the integration, coordination and harmonisation of the European electricity balancing regimes. In August, DECC published its

'Electricity Systems: Assessment of Future Challenges[1]', which emphasised the need for widespread deployment of flexible balancing technologies and smarter network infrastructure to support the changing supply and demand patterns anticipated on the GB system. At the same time, as details on the EMR emerge, DECC has confirmed that the Capacity Mechanism will be focused on ensuring sufficient levels of reliable capacity rather than flexibility[2]. Ofgem's current review is therefore at the heart of providing appropriate price signals for the flexible balancing resources that the system will need in the future.

1.1.4 Building on our previous response to the Issues Paper, in this paper we provide a summary of our views on:

- The importance of the electricity balancing arrangements,
- Gaps in the current arrangements,
- Creating a more 'market-based' set of arrangements,
- An assessment of a 'best case' package under a narrow approach, and
- How new approaches to balancing could better deliver against the SCR objectives.

1.1.5 Our views in this paper should be read in conjunction with our responses to each of the specific consultation questions posed, which are contained at Section 8.

1.1.6 In addition, we have engaged Redpoint Energy and Imperial College to undertake some modelling of the GB system out to 2030, to gain an understanding of the value of flexibility across a number of scenarios, as well as the potential impact of the current cash-out arrangements on total system costs. A summary of the assumptions, methodology and results is contained in a separate attachment.

2 IMPORTANCE OF THE ELECTRICITY BALANCING ARRANGEMENTS

2.1 Objectives for the electricity balancing arrangements

2.1.1 We consider the electricity balancing arrangements to be fundamental in providing a mechanism for the market to express a value on the supply of electricity to meet demand as close to real time as possible. As imbalance charges represent the opportunity cost of not taking any action to balance a position at all, they will influence the price paid by market participants for electricity in forward markets.

[1] DECC, August 2012. *Electricity Systems: Assessment of Future Challenges*, p.3-4
[2] DECC, May 2012. *Electricity Market Reform: Capacity Market – Design and Implementation Update,* Annex C to Draft Energy Bill, p.5

2.1.2 Balancing arrangements that depart from being ‘market-based’ risk sending inefficient and non-cost reflective signals of the value of electricity supply meeting demand in real time. This has the potential to reduce market participants’ demand for flexible technologies close to gate closure, which can have a number of unintended consequences, including:

- Insufficient market-led investment in new (particularly flexible) capacity,
- An increasing need for the System Operator (SO) to contract with flexible capacity on behalf of market participants through ancillary services, possibly with obligations to refrain from participating in the market at certain times, and
- Overall, reducing the liquidity in the spot market, making new entry more difficult and removing smaller (particularly non-VI) market participants’ abilities to balance.

2.1.3 These unintended consequences are self-reinforcing and cyclical in nature. We are therefore encouraged by Ofgem’s objectives for the SCR to:

- Incentivise an efficient level of security of supply,
- Increase the efficiency of electricity balancing, and
- Ensure compliance with the European Target model and to complement the EMR Capacity Market.

2.1.4 However, we would also urge Ofgem to consider including the efficient integration of renewable generation within its objectives. This should be a key driver in the design of the GB balancing arrangements, as the government’s decarbonisation and renewables agenda will create a step change in the balancing challenge over the next 20 years. It is therefore crucial that prices are fully cost-reflective so that market participants can make the efficient operational and investment decisions to balance their positions.

2.1.5 Further, flexible technologies will play a key role in system balancing for both *predictable* variations in the supply-demand balance (those variations which are statistically known) and *unpredictable* variations (such as loss of the largest unit on the system or unexpected variations in wind output). Post gate closure, the instant need for an immediate response to fluctuations in the supply-demand balance means that the SO is best placed to centrally procure flexible resources for unpredictable variations, rather than the market in response to dynamic price signals. The arrangements for reserve procurement are thus critical in this context, so we support the consideration of alternative reserve procurement arrangements as part of this SCR.

2.2 The flexibility challenge

2.2.1 Our analysis indicates that statistically 'known' wind variability could be significant in 2020 – ranging from around 4 GW one hour ahead of real-time, to around 12 GW three-hours ahead. This variability will need to be met by flexible capacity which is capable of ramping up over these timeframes. These findings are similar to those published by National Grid (NG), which estimates that operating reserve requirements will need to increase by between 3 GW and 12 GW within a four hour response time, primarily as a result of intermittency.[3]

2.2.2 In our response to Ofgem's cash-out issues paper, we set out our concern that by 2020, the system may be very tight in terms of flexible resources in the last hour before real-time, and would probably become heavily reliant on Demand Side Response (DSR) and interconnectors to meet the balance over a three hour period. We set out that further investment in flexible capacity will be required to manage the system in 2020, particularly for providing very fast response (less than 1 hour) flexibility products.

2.2.3 The existing supply of flexible capacity is expected to fall significantly in the period to 2020, due to closure of plant under the LCPD and other age-based retirements. We estimate that the supply of flexible capacity could fall by around 3 GW over a one hour response period and by 15 GW over a 3 hour response period (assuming no replacements). This could increase to around 22 GW over a 3 hour response period if coal plant closures are accelerated (for example if allowed LCPD running hours are exhausted earlier than expected).

2.2.4 The flexible capacity required to fill the gap left by plant closures will need to come from a variety of sources, including new supply-side capacity, DSR, interconnectors and storage. DSR and interconnectors could provide between 2 GW and around 13 GW of flexibility in 2020, while the amount of investment in new storage by 2020 is still unclear[4]. As a result, there appears to be a clear need for investment in new supply-side flexibility.

2.3 Value of flexibility in the GB market

2.3.1 We have engaged Redpoint Energy and Imperial College to conduct analysis on the value of flexibility to the GB power system in 2020 and 2030, across two scenarios. Full details are contained in the Modelling Annex accompanying this submission.

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[3] National Grid, 'Operating the electricity transmission networks in 2020, June 2011, p.22.

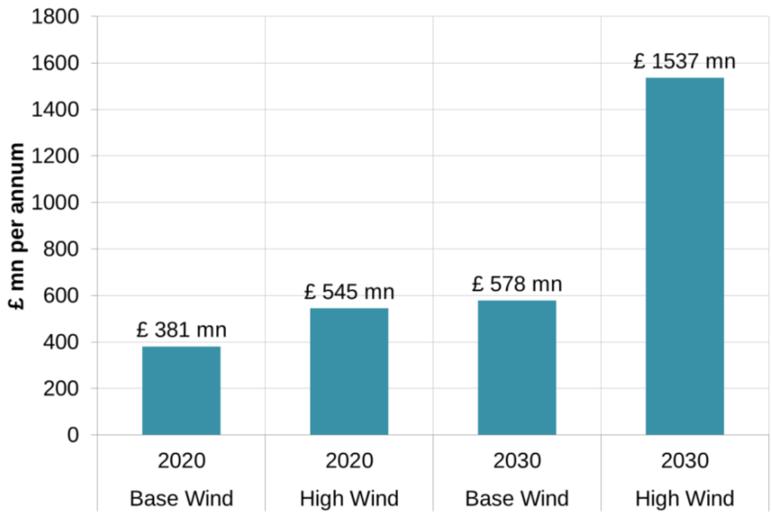
[4] National Grid estimates that DSR could provide 2GW flexible capacity by 2020, and that interconnectors could provide up to 11.4GW flexible capacity from total swing (full export to full import) though uncertainties exist concerning the availability if this flexibility, as it is not in the control of NG as system operator, and will in practice depend on the situation in neighbouring markets on a dynamic basis.

2.3.2 We have analysed two scenarios for the development of the GB power sector. The 'base' scenario is based on the central scenario from DECC's Updated Energy Projections (UEP). The 'high wind' scenario is a world of high wind capacity, in line with National Grid's Gone Green scenario from the 2012 Future Energy Scenarios.[5]

2.3.3 Our analysis suggests that without investment in flexible technologies, the costs of actions taken in the Balancing Mechanism to ensure reserve requirements are met could rise to nearly £700mn by 2020 in a Base Wind scenario, and over £800mn in a High Wind scenario.

2.3.4 For each scenario, we analysed savings in reserve cost in BSUoS with flexible supply side capacity, by replacing 4.8 GW of CCGT capacity with 4.8 GW of Smart Power Generation (SPG)[6]. The introduction of SPG could reduce the reserve costs in BSUoS[7] by £381mn in 2020 in a Base Wind scenario, and by £545mn under a High Wind scenario. Modelled savings are estimated to be even higher than these levels in 2030. Figure 1 sets out our results.

Figure 1 - Potential savings in BSUoS reserve costs (with SPG)



2.3.5 Our analysis demonstrates the value of flexibility in the GB system, which is mostly derived from mitigating the need to create reserve from already running plant in the BM, and despatching flexible SPG (standing reserve) instead.

[5] In these base scenarios, the main sources of flexibility are existing pumped storage and OCGTs (2GW by 2030). While interconnector flows are modelled, they provide energy rather than flexibility. DSR and storage are not included in either scenario.

[6] Such as Wärtsilä power plant – see attached Modelling Annex for the full set of results as well as a description of Wärtsilä power plant capabilities.

[7] Reserve costs in BSUoS are the costs of the actions taken by the SO in the Balancing Mechanism to ensure reserve and frequency response requirements are met. Total costs of reserve in BSUoS were about £238mn in 2010/11 (about 43% of total BSUoS).

2.3.6 As noted above, a range of technologies will play a role in providing future flexibility. Demand side technologies, interconnection and storage are all expected to contribute, however levels and costs are currently uncertain. In our analysis we have considered flexible supply side capacity only: other studies have attempted to quantity the optimal mix of flexibility technologies[8]. The Modelling Annex (accompanying this response) contains further details of the modelling approach, and results for all scenarios.

2.4 Interaction with the capacity mechanism under EMR

2.4.1 DECC's EMR is aimed at delivering a set of market arrangements in GB which can provide greater long term certainty to low carbon investors, while at the same time maintaining affordability and security of supply. DECC is designing a 'market-wide' capacity mechanism for GB, which will be in the form of a forward capacity auction for capacity agreements placing delivery incentives on holders. The rationale for intervention is to deal with the so-called 'missing money' problem brought about by increasingly uncertain market-based revenues for thermal plant.

2.4.2 We understand that the capacity mechanism will be technology-neutral (subject to meeting a physical verification processes). It is focused on ensuring overall capacity adequacy rather than on securing certain types of capacity. We remain concerned that while this form of capacity mechanism may increase the GB capacity margin and reduce risks to security of supply, it may not deliver the required flexible capacity at least cost to consumers. For example, it may introduce unnecessary costs in terms of reserve, emissions and wind curtailment, to the extent that it allows older (and less flexible) plant to stay on the system for longer and offer flexibility through part-loading.

2.4.3 Price signals must continue to be the main driver for market participants' day-to-day operational decisions to access flexible capacity for balancing. It is therefore critical that Ofgem's review puts these incentives in place, and that the review is aligned with DECC's work on the capacity mechanism to ensure that the package of market arrangements is coherent.

2.5 The EU framework guidelines on electricity balancing

2.5.1 In September 2012, ACER published its final Framework Guidelines on Electricity Balancing (EBFG). The EBFG provide for a Network Code on Electricity Balancing to set out the minimum standards and requirements needed for an EU-wide balancing market, and ENTSO-

[8] DECC, 'Electricity Systems: Assessment of Future Challenges', August 2012, p.3-4

E shall now commence drafting the Network Code. As Ofgem points out in its objectives, the Electricity SCR is likely to touch upon key areas under development in Europe, so it is important that any changes proposed under the SCR comply with the EBFG and Network Code to avoid further uncertainty in GB balancing arrangements at a later date.

2.5.2 We broadly interpret the EBFG's objectives to mean that balancing arrangements should be market based as far as possible. This is particularly true where the EBFG sets out that the provisions should foster competition, facilitate the wider participation of DSR and renewables, and improve social welfare and efficiency.

2.5.3 Further, the EBFG also sets out certain core specific provisions which are relevant to the Electricity SCR focus areas, in particular:

- There is a requirement on TSOs to prepare a proposal for a list of standardised balancing energy and balancing reserve products.
- TSOs shall exchange balancing energy across borders on a TSO-TSO model with a common merit order list for energy used for replacement reserves, and eventually, fast reserves.
- It stipulates that once the Network Code is in place, TSOs must implement a harmonised pricing method based on pay-as-cleared pricing unless TSOs can demonstrate to all NRAs a different pricing method is more efficient.
- There is a requirement for TSOs to procure as many reserve products as possible in the short term, with a focus on procuring reserves in line with common principles to progress towards harmonisation.

2.5.4 The Electricity SCR is an excellent opportunity for Ofgem to lead by example in aligning the GB balancing arrangements with the direction of travel in Europe. We recommend that Ofgem assesses the details of the requirements above against its primary considerations to ensure that the new GB balancing arrangements are compliant with the Network Code from the outset.

3 GAPS IN THE CURRENT ARRANGEMENTS

3.1.1 In our response to the cash-out issues paper, we supported Ofgem's rationale for review and agreed with the broad range of issues set out in the paper. We argued that the arrangements as they stand may present barriers to the establishment of an efficient mix of flexible technologies in the future.

3.1.2 Our primary concern is centred on the inefficient valuation of flexible resources in the cash-out arrangements, which is then reflected in spot market prices. The need for prices to clearly reflect the value placed on flexible resources is of utmost importance, particularly given the need to integrate intermittent generation efficiently. There are a number of barriers to this in the current arrangements, including:

- **Price calculation**: the cash out price calculation is based on the weighted average cost of actions rather than the marginal cost, and does not accurately allocate reserve costs, which means that the price does not reflect the marginal value of energy.
- **Pricing method (pay-as bid)**: pay-as-bid pricing can make it difficult for smaller balancing resources to participate, given that analysis to anticipate the market clearing price is required. Such parties may adopt an over cautious pricing strategy as a result, which can dampen cash-out prices and therefore signals to invest.
- **Mixing different products**: the BM mixes different products procured through different means and over different timeframes. This generates cash-out prices which are not reflective of the true costs of procuring the individual products used at that point, and as such can cause the misallocation of costs to market participants over the long run.
- **Non-costed actions**: the use of non-costed actions means that no price signal is available at these times for market participants to respond to.
- **SO decisions**: the SO may be somewhat physically oriented and conservative, which is influenced by the SO incentive regime currently under review by Ofgem.

3.1.3 Other issues exist with the cash-out arrangements which reduce their potential as reference prices, including:

- **Unpredictability** caused by the complex calculation and use of different services,
- A **lack of transparency**, and
- An **artificial spread** in the value placed on energy caused by the dual price system, which causes an asymmetric risk for parties with an imbalance.

3.1.4 Further, it is important for Ofgem to consider how its list of considerations under Electricity SCR will comply with the specific requirements of the Framework Guideline on Electricity Balancing as set out in 2.5.3. For example, as we discuss below, the current arrangements create various challenges for producing a common merit order and a clean balancing energy product for cross border exchange. This is primarily because the BM is a continuous platform for the procurement of a mixture of balancing products rather than an explicit merit order.

3.1.5 Further, the EBRG preference for short term reserve markets to reduce barriers to entry for DSR, low carbon generators and smaller market participants is a significant departure from current arrangements, but within the scope of this SCR. Current arrangements mean that National Grid can procure reserve over different timeframes which increases its certainty of having the reserves available, but risks foreclosing the market to short term flexible resources which may be more efficient to operate (especially for avoiding unnecessary emissions and the curtailment of wind). The SO incentives regime also has a large influence on the type of reserve resources that National Grid despatches, so it is important for this to align with any changes made in the balancing arrangements to comply with the EBFG.

4 CREATING MORE 'MARKET-BASED' ARRANGEMENTS

4.1.1 In the Issues Paper document from November 2011, Ofgem set out two possible approaches to the SCR:

- Narrow scope: this approach would continue with the current direction of travel from past cash-out reform attempts, bringing together all of the identified issues but dealing with each of them individually.

- Wider scope: this approach would allow consideration of solutions that would represent a significant departure from the current approach to balancing in GB.

4.1.2 This thinking has then been refined in the Initial Consultation document, in which a range of potential policy packages are provided on a spectrum from more mechanistic to more 'market-based'. We note that reforms to improve the price inputs for cash-out (which includes attributing a price to currently non-costed SO actions, and more accurate targeting of reserve costs) are included in all of the policy packages.

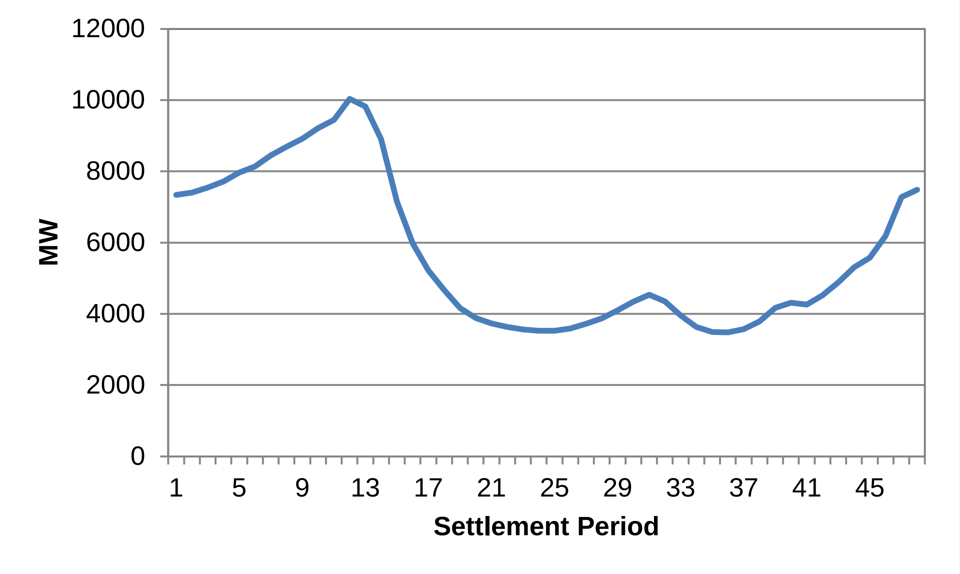
4.1.3 We support this general direction of travel towards more 'market-based' and cost reflective electricity balancing arrangements. As we have previously stated, in our view the best way to deliver an optimal mix of flexible technologies is by maximising participation in effective market-based mechanisms, which in turn will facilitate efficient price discovery. More market-based balancing arrangements can reduce the incentives for market participants to provide 'headroom' at gate closure by going long, which could reduce overall system costs. This is discussed further in Box 1 below.

Box 1: The cost of 'free' headroom

The System Operator has a responsibility to ensure that sufficient reserve is available in each period. One source of this reserve is the so-called 'headroom' on generators that are operating at less than full output. This headroom can be created by the SO through clearing bids and offers in Balancing Mechanism. It may also be provided for 'free' (i.e. no cost to the SO) by the market if, at gate closure, generators submit Final Physical Notifications which are lower than their stated availability.

The historic levels of free headroom are shown Figure 2, calculated as an average of each settlement period over the three years 2009 – 2011. The minimum estimated 'free' headroom occurs at midday and at evening peak. Headroom is high overnight when demand is lowest and less flexible generators or those with high start costs may reduce output to a minimum, rather than turning off.

Figure 2: - Estimated 'free' headroom available to System Operator (2009 - 2011)[9]



Under current cash out arrangements, portfolio generation owners have an incentive to schedule generation below the maximum capacity, to self-provide reserve and avoid potentially high System Buy Prices for being short. Alternatively, output may be held back by generators to create the option provide energy at a premium in the BM (e.g. if the market is short, or to resolve constraints), or for operational reasons.

We have analysed the impact of generators as a whole providing a minimum of 1 GW of 'free' headroom. This value has been chosen as a conservative estimate of the actual 'free' headroom observed (given that our historic analysis may overestimate headroom). We find that this so-called 'free' headroom does indeed reduce reserve costs in BSUoS (by £105mn in 2020) as fewer actions are taken by the SO to create reserve. However with generators providing headroom, their generation is reduced and additional, higher cost generation capacity has to be scheduled. Our modelling indicates that this could increase wholesale

[9] Source: Balancing Mechanism data, Redpoint analysis. Calculated from FPN and MEL aggregated at a station level. This approach counts headroom on the entire station if one unit is operating, and may significantly overstate the level of headroom relative to a calculation done for each Balancing Mechanism Unit.

power prices by £0.5/MWh. This is equivalent to a £148mn increase in costs for consumers, which is greater than the £105mn saving in reserve costs in BSUoS.

Our analysis therefore demonstrates that there is a cost to 'free' headroom, and that incentives for generator to provide headroom may impose a net cost on consumers through increases in the wholesale price of power.

4.1.4 We agree it is sensible to consider whether the original concerns that led to the more mechanistic set of current arrangements can now be overcome such that more market-based arrangements can be facilitated. In the next section we explore some of these arguments, as well as the more recent arguments raised as part of the stakeholder workshops.

4.1.5 The fundamental question of whether a narrow or wide approach should be adopted as part of the review still remains. In our previous submission to the Issues Paper we argued that while the narrow scope option could make some notable improvements, more fundamental changes may be required to deliver on the review principles. Having reviewed the material from the stakeholder workshop, it appears that the decision of whether to adopt a narrow or wide approach ultimately rests on three questions:

1) Is a narrow approach that seeks to deliver a more market-based set of balancing arrangements using the current BM practically feasible?

2) Is compromise required to deal with the various technical uncertainties under a narrow approach, and if so, would this approach still achieve the SCR objectives?

3) More fundamentally, will the current approach to electricity balancing remain fit-for-purpose in future with increased intermittent generation on the system?

4.1.6 We maintain the view that new approaches to balancing will be required to meet the future flexibility challenge in GB. However it is important to first consider from the 'ground up' whether more market based balancing arrangements can be delivered using the current approach, or whether the practical difficulties are such that achievement of the SCR objectives may be undermined. This is the focus of Section 5 below.

5 A NARROW APPROACH USING THE CURRENT BM

5.1.1 This section considers the key elements of potential reform under an approach that seeks to retain the current BM (what we refer to as the 'narrow approach'). We consider the following key elements:

- More marginal cash-out
- Single vs dual cash-out
- Pay-as-bid vs pay-as-cleared for energy balancing services
- Attributing a cost to currently non-costed actions
- Improved allocation of reserve costs

5.1.2 Below we consider the potential benefits of reform in each of the above areas, the technical issues that stakeholders have raised, and the potential compromise that may be required to achieve the SCR objectives.

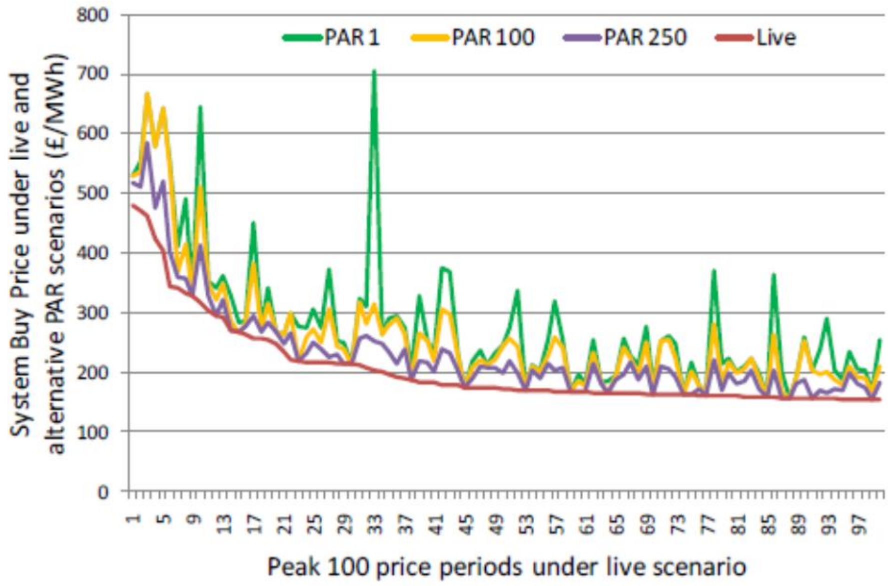
5.2 More marginal cash-out

5.2.1 In principle, we believe that cash-out prices should be fully cost reflective, based on the marginal value of energy in a given half hour. Without this, there may be inadequate incentives to invest in the flexibility and peaking capacity required to manage the system with a high penetration of intermittent generation.

5.2.2 At the stakeholder workshop on this issue, Ofgem officials presented a compelling argument that the so-called 'missing money' problem is a reality under the current arrangements. This is illustrated in Figure 3 below, which shows the potential extent of mispricing in tight periods using the current methodology (Price Average Reference of highest 500 MWh, or 'PAR 500').[10]

[10] Ofgem, 'More marginal cash-out prices', Stakeholder workshop slides, 3 October 2012. Available at: http://www.ofgem.gov.uk/Markets/WhlMkts/CompandEff/electricity-balancing-scr/Documents1/Cash-out%20marginality.pdf

Figure 3: Potential extent of cash-out mispricing due to averaging methodology



5.2.3 As Figure 3 illustrates, in this sample cash-out prices have regularly been up to around £200/MWh lower under a PAR 500 methodology relative to the counterfactual marginal pricing methodology ('PAR 1'). Even at a hypothetical PAR 100 level the extent of mispricing in tight periods appears to be high, at around £100/MWh. This clear dampening of price signals will materially affect the value of flexibility from all sources, including supply-side, DSR, storage and interconnection. Logically, the extent of 'peakiness' in cash-out and balancing prices will flow through to investment decisions in these flexible solutions.

5.2.4 We note the view from stakeholders as summarised in the minutes from the Workshop 3:

"On the incentive to build flexible generation, participants said cash-out is not a significant consideration for investment decisions because investors take a very long-term view and cash-out prices are difficult to forecast. Participants said that in a perfectly rational market, the cash-out price should feed through to forward prices but unsure about the extent to which this occurs in practice."

5.2.5 While investors do indeed take a long-term view when making decisions, different types of investments will be based on different sets of information. For investments in flexibility, the expectations of short term price fluctuations will be factored into the business case, as this is the key value that the product delivers. This will clearly not be the only factor driving investment, but it will be a relevant parameter in the revenue potential analysis.

5.2.6 Moreover, this view as expressed may be symptomatic of the problem itself – a lack of transparency in price signals. Cash-out prices are indeed difficult to forecast, due to the inherent uncertainty close to real-time, but perhaps more fundamentally due to the mechanistic approach that combines multiple products and is reliant on a somewhat subjective flagging process. If a more market-based approach was taken to balancing, in which energy was truly separated, there could be knock-on benefits to short-term liquidity and reference price formation. With more reliable and liquid short-term prices, investors in flexibility will have more confidence using long-term financial instruments that are hedged to these prices – investments in flexibility should not be viewed as a pure 'merchant' activity.

5.2.7 The stakeholder workshop highlighted a number of issues that would need to be overcome before a move to more marginal pricing could be achieved. In Table 1 we summarise the key issues and stakeholder feedback, then provide our high-level observations.

Table 1: More marginal cash-out – issues raised

Issue identified	Details	Key high-level views from workshop	Wärtsilä observations
'Pollution' means there may be distortions with a marginal price	System actions and misallocated reserve costs are the main sources of 'pollution' National Grid explained that its system action 'flagging' methodology is ~98% accurate	Question whether flagging accuracy of 98% is sufficient to justify a fully marginal price (PAR 1) Analysis requested on the extent of potential pollution that could remain at different levels of PAR	Fundamentally this is a question of whether the multiple 'products' currently included within the cash-out price can be separated, such that a marginal energy product can be defined Success rests on the accuracy of the system action flagging process and the reserve cost allocation methodology, both of which are somewhat subjective and may lack transparency Based on feedback from industry, it may be difficult to justify PAR 1
Isolating 'the' marginal action	Balancing actions are taken on a continuous basis – over the half-hour settlement period in question as well as at least two half-hour periods prior (i.e. gate closure period) Question of whether the marginal action should be the highest cost action taken in the half-hour, or cost of the last action	View that in principle, 'the' marginal action should be considered the highest cost action in the relevant half-hour Concern that the marginal action may be ill-defined if reserve costs are mis-allocated	Agree that marginal action should be based on the highest cost action in the relevant settlement period, to reduce scope for judgement Success of reserve cost allocation methodology is important for ensuring the marginal action reflects the marginal cost of energy
Key interactions	More marginal could create a larger spread if dual cash-out prices are retained More marginal could increase incentives to spill if a single price is implemented RCRC could increase with more marginal if pay-as-bid for balancing services is retained	Small and intermittent generators may face increasingly excessive imbalance exposure if dual pricing is retained More marginal pricing could actually increase the incentives to part-load going into gate closure	Agree that more marginal pricing could have the unintended consequences of increasing incentives to part-load and unduly penalising small and intermittent generators, <u>but</u> only if dual pricing is retained A single marginal price could have positive impacts on competition and liquidity, which should reduce incentives to part-load

5.2.8 In sum, we believe there is a strong case to make cash-out prices more marginal. If more marginal pricing is introduced, it would seem sensible to move to a single cash-out price so as to minimise the unintended consequences, particularly for small and intermittent players. However, stakeholders have raised some genuine concerns about the residual uncertainty in the system action flagging methodology and the potential misallocation of reserve costs. Taking a narrow approach to the review, unless these uncertainties can be resolved it may be difficult to justify moving to PAR 1, and instead there may need to be a compromise reached (e.g. PAR 100).

5.3 Single vs dual cash-out

5.3.1 We support the establishment of a single rather than a dual cash-out price.

5.3.2 The dual pricing approach creates asymmetric risk for market participants, which has knock-on impacts to the trading strategies they adopt. As is well-documented, participants on average tend to have strategies under which they plan on taking an *imbalance* ahead of gate closure (typically going long). While system length may create 'free headroom' from an SO perspective, it is not necessarily efficient from an overall system cost perspective, as our analysis demonstrates. We understand that providing strong incentives to contract ahead was a key objective of the NETA market design in GB, however dual pricing may be having unintended consequences. For example, the spreads may go some way towards explaining the lack of liquidity in GB prompt markets, as the asymmetric risk is more efficiently managed within a portfolio. This lack of liquidity could in turn represent a barrier to entry for small and independent players into the GB market, and may have exacerbated incentives for vertical integration.

5.3.3 It is sensible to pose the question whether the original rationale for dual pricing remains (or ever was) valid. We note that Stephen Littlechild has recently reviewed the original rationale for dual pricing (in a response to Ofgem's Issues Paper), making the following observations:[11]

- The notion that those market participants who are short impose greater costs on the system than the costs saved by those who are long is not necessarily correct – participants who are out of balance in one direction tend to offset the SO's costs, and should have essentially the same price as market participants that are out of balance in the other direction.

- The original thinking was that dual pricing would encourage participants to balance their own positions, but empirical evidence suggests that it has in fact encouraged parties to plan to take an imbalance into gate closure.

- It is not clear that weight should be attached to objectives such as self-balancing or minimising the role of the SO, given that National Grid has over the past 10 years established itself as an experienced and competent System Operator.

[11] Stephen Littlechild, 'Response to Ofgem's consultation on electricity cash-out issues', January 2012. Available at: http://www.ofgem.gov.uk/Markets/WhlMkts/CompandEff/CashoutRev/Documents1/Stephen_Littlechild_response_to_electricity_cash-out_issues_paper[1].pdf

5.3.4 We concur that the original reasons for implementing a dual cash-out pricing regime may no longer be relevant, and that a single price may now be possible. Table 2 contains a summary of the issues raised as part of the stakeholder workshop, alongside our high-level observations.

Table 2: Single vs dual cash-out – issues raised

Issue identified	Details	Key high-level views from workshop	Wärtsilä observations
Potential increase in incentives to spill onto the system	Participants may have an incentive to hold-back energy until gate closure then spill onto the system if there is a single price, which could increase costs for the SO There are a number of potential solutions if spilling is a concern, for example single pricing on consumption accounts, and dual pricing on production accounts (as in Nordpool)	Debate as to whether participants would be more or less likely to go long if a single price was adopted Some argued that a single price could encourage more spilling and thus decrease liquidity in forward markets, whereas others argued that liquidity would increase given the greater simplicity and transparency	The current dual price with a large spread creates asymmetric risks that encourage parties to take an imbalance into gate closure (typically going long) While there may be less incentive to self-balance with a single price relative to the current arrangements, a single price with no spread should provide more symmetric risks on being long vs being short – there is no asymmetric incentive either way A single price is simpler and more transparent, which should increase liquidity and competition in short-term markets
Potentially increased uncertainty for the SO	A single price may increase the uncertainty around the NIV forecast (because of the potential increased incentive to spill on to the system), which could increase costs for the SO	Increased uncertainty may lead to the SO needing to contract more reserves An information imbalance could be introduced to reduce uncertainty on NIV forecast	The imbalance would be based upon the fundamental supply-demand position, which the SO would soon adapt to (as it has to other changes such as shorter gate closure) An information imbalance charge may be worth considering
Key interactions	A single price may reduce the asymmetric risk associated with more marginal cash-out A single cash-out price with pay-as-bid for balancing services may encourage spilling into the BM Single trading accounts aligns with a single cash-out price	Small and intermittent generators may face increasingly excessive imbalance exposure if dual pricing is retained	Agree that a move to single cash-out may be required so as not to unduly penalise small and intermittent generators exposed to more marginal prices If single cash-out is adopted, balancing services should be pay-as-cleared to avoid distorting behaviour The debate on single trading accounts is irrelevant if a single price is adopted

5.3.5 In sum, there appears to be a strong rationale to move to a single cash-out price. We suggest that, as a single price will create symmetric rather than asymmetric risks, the overarching incentive should be to balance one's position. The risk of spilling should not be a major concern with a single price, rather there is a more symmetric incentive to either be long or short depending on market conditions. We note that Ofgem put forward a number of potential compromise solutions to mitigate the risk of spilling, to the extent that it does remains a concern. For example the Nordpool approach of dual pricing on production accounts and single pricing on consumption accounts has been suggested. Beyond providing a potential benefit to DSR providers, we do not see how this proposal would produce a materially different outcome to a dual pricing regime in GB.[12]

5.4 Pay-as-bid vs pay-as-cleared for energy balancing services

5.4.1 We would support a move to pay-as-cleared pricing for the provision of balancing energy in the BM. In our view it is a key component in a package of balancing arrangements that are more market-based. Pay-as-cleared pricing would reward balancing services in the BM at the cost-reflective marginal value of energy, which will be important in bringing forward the required flexibility. Also, as Ofgem recognises, there is less second guessing with a pay-as-cleared approach, with market participants more likely to submit cost-reflective bids and offers.[13]

5.4.2 As discussed in Section 2, ACER's final Electricity Balancing Framework Guidelines (EBFG) are quite firm on this issue. Balancing energy must be rewarded on a marginal pay-as-cleared basis unless TSOs can collectively make a case to the regulators that an alternative pricing methodology should be adopted across all member states. We recognise that there are clearly some fundamental differences in these other markets that have driven the current pricing methodology adopted (e.g. lower level of constraints). However this is an area in which ACER has in effect mandated harmonisation, given the potential distortions to cross-border trade that could come about if different pricing methodologies are adopted in different member states. On this basis it seems reasonable to assume that GB will need to move to pay-as-cleared pricing in order to comply with the EBFG and subsequent Network Code.

5.4.3 Table 3 contains the key issues that would need to be overcome before a move to pay-as-cleared pricing of balancing energy could be introduced, as well as our observations.

[12] We note that it would also be inconsistent with a move to single trading accounts.
[13] Although we note that for these arguments to hold, there needs to be a separate procurement process for energy.

Table 3: Pay-as-bid vs pay-as-cleared for energy balancing services – issues raised

Issue identified	Details	Key high-level views from workshop	Wärtsilä observations
Could lead to market power concerns	Ofgem originally considered that pay-as-bid pricing may mitigate market power, however this may no longer be such a concern In theory, pay-as-bid and pay-as-cleared should produce similar results, to the extent that under the former there is an incentive to bid the expected clearing price	In assessing the potential for market power, it is competition for the marginal plant that is important, rather than the whole market In a competitive market pay-as-cleared should encourage bids and offers at closer to SRMC in most periods (of non-scarcity)	Market power is a separate issue that can be covered elsewhere in the regulatory arrangements Agree that pay-as-cleared should lead to more cost-reflective bids and offers in the BM, taking the 'guesswork' out of it
Difficult to extract an homogenous product upon which to derive a clearing price	Currently actions in the BM are taken for a variety of reasons over multiple timeframes, therefore hard to define a clearing price for 'energy'	The BM is more like a bilateral procurement process than a market in which a clearing price can be established Potential loss of synergies for the SO if the procurement of energy products was separated from other actions	This is a similar issue to the marginal cash-out pricing issue – fundamentally it is a question of whether the multiple 'products' currently included within the cash-out price can be meaningfully separated under the current BM. Our view is that they cannot, and therefore new approaches to balancing will be required (e.g. a Balancing Energy Market) SO concerns at a loss of synergies if balancing products are unbundled are valid, however these need to be weighed against the potential benefits of more cost-reflective and transparent pricing
Key interactions	Pay-as-bid may be inconsistent with single marginal cash-out, as parties would receive more from spilling than offering balancing services into the BM		Pay-as-cleared pricing for balancing energy would be more consistent with single marginal cash-out

5.4.4 In sum, we consider that a pay-as-cleared pricing methodology for balancing energy is more consistent with a market based approach to balancing, and with the requirements under the final EBFG. However we recognise that it may not be possible to implement a pay-as-cleared approach using the current BM, given the continuous nature of SO actions and the difficulty in isolating pure energy products.[14]

5.4.5 While these issues could be resolved to an extent using the same methodology as is applied to isolate non-energy actions for the purposes of cash-out, this would leave the same residual

[14] Pay-as-cleared approaches normally require an auction based market rather than continuous trading.

uncertainties. Therefore a new approach to the procurement of balancing energy (such as a Balancing Energy Market) may need to be considered in order to implement pay-as-cleared pricing. We discuss this in Section 6 below.

5.5 Attributing a cost to currently non-costed actions

5.5.1 The Initial Consultation suggests that part of the 'missing money' problem may be due to the fact that some actions taken by the SO are currently 'free' (e.g. voltage control, automated load disconnection). Applying an appropriate cost to these actions would ensure that the balancing arrangements are more cost-reflective, which would have knock-on impacts to investment incentives. The key difficulty is in estimating an administrative Value of Lost Load (VoLL) representative of all customers to apply in these rare circumstances. As noted by stakeholders at the workshop, given that these price spikes could be quite severe, the role of ex-ante warnings ahead of scarcity events will be important.

5.5.2 We support the move to more cost-reflective balancing arrangements that take account of these infrequent events. We note that this is similar to the proposed approach on the gas side in GB, so ensuring consistency across the two sectors is welcome. We also note the close interactions with the EMR Capacity Mechanism, which we understand will seek to resolve the missing money problem by securing a centrally determined capacity margin via a forward auction.

5.6 Improved allocation of reserve costs

5.6.1 We would support a move to a more accurate allocation of reserve costs, given the importance of cost-reflective price signals in signalling the value of flexibility.

5.6.2 The SO currently procures reserves ahead of gate closure, which are effectively held as options that it can exercise in order to avoid high balancing prices. However, we understand that the option fees for the reserve (and also the utilisation fees in the case of non-BM STOR) may not currently be accurately allocated into the periods in which the reserve is actually utilised. Reserve creation costs – the cost of warming plant in readiness for dispatch in a future period – may also be mis-allocated. This mis-allocation may lead to distortions, to the extent that the energy-only cash-out price does not reflect the full energy-only costs incurred in the period. Further, without accurate targeting of reserve costs into the right periods, the incentives for flexibility providers operating on an energy-only basis could be reduced (as they may be pushed out of merit).

5.6.3 Table 4 contains the key issues identified during the stakeholder workshop, as well as our observations.

Table 4: Improved allocation of reserve costs – issues raised

Issue identified	Details	Key high-level views from workshop	Wärtsilä observations
Difficult to establish a methodology for reserve cost allocation	Current methodology to allocate based on last year's usage may be inaccurate both now and in the future Three main options are suggested – two based on expected usage and a third option based on determining the 'replacement cost' of the reserve	Past discussions on this issue indicate that accurate allocation is very difficult on an ex-ante basis Uplift based on expected usage may be the best option, but it is still likely to be imperfect Allocation based on replacement cost was discounted given the complexity	The overarching issue here is that we are trying to load the costs of one product (reserve) into another (energy), when in fact the two products have been purchased on different timeframes Agree that a methodology based on previous years will not be appropriate in future, particularly as the reserve requirement will change more dynamically as wind penetration increases Agree that uplift based on expected usage may be the best option, but it may still result in some mis-allocation
Difficult to identify appropriate periods to allocate reserve creation costs	A flagging methodology as is currently used for system actions could be used to identify reserve creation costs	This is a complex area, likely requiring judgement from the SO in real-time	A flagging methodology may provide for more accurate allocation than at present, however it may suffer from a lack of transparency

5.6.4 While it appears feasible that some form of methodology could be established that improves the allocation of reserve costs in cash-out, there may be significant residual inaccuracy that remains a concern for stakeholders. Inaccurate allocation of reserve costs may reduce the cost-reflectivity of cash-out prices, and undermine the case for moving to a more marginal price. The primary issue here is that, under a narrow approach, we are attempting to layer on the cost of one product (reserve) into the price of another (energy). This may produce sub-optimal results, and instead a new approach that seeks to price the two products on a separate and transparent basis could be considered.

5.7 A hypothetical 'best case package' under a narrow approach

5.7.1 Our objective in this section has been to consider what we interpret to be the 'best case scenario' for what can be achieved within the confines of the current BM. We have taken into account the issues that Ofgem has put forward, the views of stakeholders, and provided our own views on what is practical. Table 5 summarises our view of the key outstanding issues under a narrow approach, some of the practical compromises that may be needed, and our view on a hypothetical package.

Table 5: Open issues and a hypothetical 'best case package' under a narrow approach

Reform option	Key open design issues	Potential compromise required	Hypothetical package
More marginal cash-out	It may not be possible to remove all the 'pollution' from non-energy products in the marginal energy price	PAR 1 may not be practically feasible given the residual uncertainty in system action flagging and reserve cost allocation	PAR 100
Single or dual cash-out prices	Single cash-out may provide incentives to spill into the BM	Single cash-out appears achievable[15]	Single
Pay-as-bid or pay-as-cleared for balancing energy	Given that the BM is a continuous bilateral procurement process, it would be difficult to extract an homogenous energy-only product for the purposes of deriving a clearing price	It does not appear that a pay-as-cleared pricing methodology could be adopted under the current BM	Pay-as-bid
Attributing a cost to non-costed actions (i.e. incorporating VoLL)	Establishing an administrative VoLL	This should be achievable, but note strong interactions with other elements such as marginal cash-out and pay-as-cleared for balancing energy	VoLL inserted
Improved allocation of reserve costs	Difficult to establish an ex-ante methodology for reserve cost allocation Flagging methodology for reserve creation costs (if adopted) may be somewhat subjective	Residual inaccuracies in cost allocation may undermine the case for marginal cash-out	Uplift based on expected usage

5.7.2 As Table 5 sets out, if Ofgem is to take a narrow approach to the review there are likely to be some barriers to achieving an optimal set of arrangements.

5.8 Assessment of 'best case' narrow package against Ofgem's SCR objectives

5.8.1 The question then becomes whether this hypothetical set of arrangements would still meet Ofgem's SCR objectives. We have undertaken this assessment in Table 6 below.

[15] We note that single or dual trading accounts could be implemented alongside single cash-out.

Table 6: Assessment of hypothetical 'best case package' against Ofgem's objectives

Objectives		Positives	Negatives	Overall assessment
Incentivise an efficient level of security of supply	Incentivise optimal level of investment (through appropriate price signals)	Firm interruption priced at VoLL should enhance investment signals Single and more marginal cash-out price provides sharper signals and may drive an increase in liquidity	Cash-out prices not fully marginal, leaving an element of missing money System flagging and reserve cost allocation may be imperfect Pay-as-bid for balancing energy may raise a barrier to entry for flexibility providers	
	Pay firm customers appropriately for the DSR service they provide if their demand is involuntarily interrupted	Firm customers compensated at VoLL for involuntary interruption		
	Incentivise plant flexibility and DSR	More marginal cash-out prices can enhance signals for flexibility Single cash-out can encourage greater market participation	Pay-as-bid for balancing energy may under-value flexibility Cash-out prices would not be fully cost-reflective	
Increase the efficiency of balancing	Minimise market distortions due to the need for the SO to balance the system	Reserve costs more accurately allocated	System action flagging and reserve cost allocation methodologies imperfect, which may lead to distortions	
	Incentivise participants to balance their position as far as is efficient	Single and more marginal cash-out should provide strong incentives for participants to balance		
	Appropriately reflect the SO's costs for balancing in cash-out prices	Cash-out price more reflective of 'energy-only'	System action flagging and reserve cost allocation methodologies imperfect, which may lead to distortions	
Ensure our balancing arrangements are compliant with the EU Target Model and the EMR Capacity Mechanism (CM)	Align GB balancing arrangements with EU balancing and capacity allocation and congestion management framework guidelines		Pay-as-bid for balancing energy would not comply with EBFG System action flagging and reserve cost allocation methodology could lead to distortions in common merit order	
	Work closely with DECC to ensure cash-out arrangements and the EMR CM complement each other	Too early to comment		

5.8.2 As Table 6 sets out, while this hypothetical package of reforms may represent an improvement relative to the status quo, it is not clear that it would meet the SCR objectives. In particular, less than fully marginal cash-out may not meet the twin objectives of incentivising an efficient level of security of supply and increasing the efficiency of balancing. Further, it does not appear that this package would be compliant with the EBFG, given that balancing energy in the current BM would need to be compensated on a pay-as-bid rather than a pay-as-cleared basis. More generally we are not convinced that such a package of reforms would remain fit-for-purpose in future with increased intermittent generation on the system.

5.8.3 In the next section we explore an alternative package of arrangements that we consider may better facilitate the achievement of the SCR objectives.

6 NEW APPROACHES TO BALANCING

6.1.1 In our view the SCR objectives could be better achieved if Ofgem was to depart from the narrow approach and instead pursue new approaches to balancing. In this section we set out our initial thoughts on what we consider to be a coherent package of reforms under a wider scope approach.

6.1.2 The key elements of our proposed package are as follows:

- Market splitting where transmission constraints are most prevalent
- A balancing energy market held at gate closure
- A day-ahead reserve market accessible to both the SO and market participants
- An information imbalance charge

6.1.3 We discuss each of these below, then we assess the package against the SCR objectives.

6.2 Market splitting

6.2.1 Market splitting, if implemented, may allow for a more structural separation of energy and system actions in the electricity balancing arrangements.

6.2.2 We understand that there is a requirement to implement market splitting under the EU Target Model, for example the Capacity Allocation and Congestion Management (CACM) Network Code states that:

"Bidding zones will be defined to ensure efficient congestion management and overall market efficiency. Bidding zones can be subsequently modified by splitting, merging or adjusting the zone borders. Bidding zones will be consistent across different market timeframes and will be relatively stable across time, while reflecting changing network conditions.[16]*"*

6.2.3 There is then a defined process by which either TSOs and/or the National Regulatory Authority (NRA) can launch a review of the geographic location of bidding zones, and the criteria that must be applied by the NRA to assess a proposal (in an open and transparent process). We understand that market splitting is something Ofgem is seriously considering due to the recent increase in constraint costs in GB. For example, in a March 2012 open letter to stakeholders on the implementation of the EU Target Model, Ofgem states that:

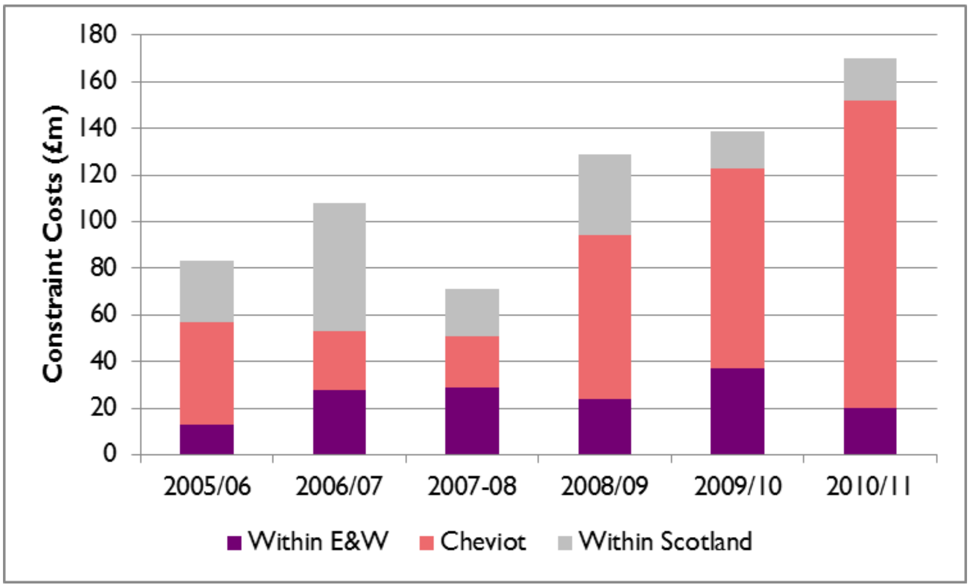
"We have already started seeing evidence of changes in the GB market. Some of these changes are particularly relevant for the implementation of the Target Model. For example, constraint costs have increased from £84 million in 2005/2006 following the introduction of BETTA to £170 million in 2010/2011. There have been several high profile incidences this winter of high constraint costs at times of high wind generation and low demand. As the penetration of wind increases, more intermittent generation with low load factor will share network resources with thermal generation putting pressure on the way constraints are currently managed on the system.[17]*"*

6.2.4 The zones could be defined according to the location of the major transmission constraints. Market splitting would represent quite a major reform, with a number of important implications both for market design as well as cost allocation across the country. For example, multiple pricing zones for the purposes of CACM could imply the need for zonal balancing mechanisms / markets, as well as zonal capacity auctions under the EMR CM.

6.2.5 Based on the location of National Grid's current constraint costs, it may not be necessary to have a significant number of zones in order to achieve a significant improvement in price signals. As Figure 4 illustrates, an increasing proportion of constraint costs are incurred to resolve the constraint across the Cheviot boundary between England and Scotland (close to 80% in 2010/11).

[16] ENTSO-E, Network Code on Capacity Allocation and Congestion Management, September 2012
[17] Ofgem, 'Open letter: Implementing the European Electricity Target Model in Great Britain', March 2012, p.2

Figure 4: Location of National Grid's constraint costs – 2005/06 to 2010/11[18]



6.2.6 Ofgem's Electricity SCR Initial Consultation document recognises the close interactions between potential market splitting and the electricity balancing arrangements, however we would suggest that this should be elevated to a 'primary' consideration.

6.2.7 From an electricity balancing perspective, market splitting would give greater confidence that the cash-out price(s) would reflect the price of energy-only products, such that the case for a fully marginal balancing energy price could be advanced. Market splitting into just two zones defined at the Cheviot boundary (as described above) would mean that the balancing energy prices in these two zones would reflect the majority of constraint costs currently incurred in GB. The flagging process for the remaining system actions taken to resolve constraints within zones may still be needed, however the materiality of any residual methodological errors in the process would be significantly reduced.

6.3 Balancing energy market (BEM)

6.3.1 With market splitting in place to efficiently price the most material transmission constraints, we believe that a BEM (or multiple zonal BEMs) could be implemented. We envisage that the BEM would be an auction held at gate closure for a homogenous energy-only product, priced on a fully marginal pay-as-cleared basis. In our view this would better meet the SCR objectives to incentivise an efficient level of security of supply and encourage efficient balancing, and for the reasons outlined above we believe that a BEM is the only realistic way to introduce pay-as-cleared priced in accordance with the EBFG.

[18] National Grid, 'Electricity SO incentives – Historic Costs 2005/06 to 2010/11'

6.3.2 We recognise that the option of a BEM was discussed at the first workshop, at which stakeholders raised a number of concerns (in particular with respect to the scale of change implied). Table 7 sets out the key design issues raised by Ofgem and commented on by stakeholders, as well as our observations.

Table 7: Balancing energy market – issues raised

Issue identified	Details	Wärtsilä observations
When would the BEM be held?	Ofgem set out two alternative models: 1) BEM held at gate closure with the SO as the only counterparty 2) BEM held before gate closure with bilateral trading also supported	A BEM held at gate closure would be more consistent with the EU Target Model, which requires continuous intra-day trading up until gate closure close to real-time A BEM held at gate closure (an hour ahead of real-time) should not create undue issues for the SO, provided that market splitting has taken care of the most material constraints (i.e. minimising the need for system actions post gate closure)
How would imbalances be dealt with?	A BEM would clear based on a forecast Net Imbalance Volume (NIV) rather than being based on actual SO actions Under model 1 above, participants would be cashed out on their gate closure imbalances at the clearing BEM price A further incentive on subsequent post gate closure imbalances may be needed	Participants could be initially cashed out on the difference between their contracted positions and metered output at gate closure, at the BEM clearing price There is not necessarily a need for a post gate closure Balancing Mechanism (similar to what we have today) – the SO could resolve any imbalances at least cost using pre-contracted response and the available (and as yet unused) pre-contracted reserve. The costs of these post gate closure actions could be allocated via the information imbalance charge levied on metered output vs FPNs. See our proposed strawman below for more details.
Would a BEM require an incentive on participants to submit accurate information to the SO?	In order to forecast a NIV for the purposes of the BEM, the SO would require accurate information on demand and available generation ahead of real-time If market participants submit inaccurate information, the SO may take energy balancing actions through the BEM which then need to be unwound post gate closure	Generators could be required to provide PN data 4-5 hours ahead of gate closure, and then the SO could communicate demand and the NIV forecast ~4 hours ahead of gate closure (which could be refined in the run-up to gate closure) To provide an incentive for accurate PNs, a portion of the information imbalance charge could be levied on metered output vs the within-day PN

6.3.3 Taking onboard the design issues raised as part of the consultation, we would envisage the BEM working according to the following steps:

- Generators to provide Physical Notification (PN) data ~4-5 hours ahead of gate closure, and then the SO communicates demand and Net Imbalance Volume (NIV) forecast ~4 hours ahead of gate closure. The NIV forecast could then be refined in the run-up to gate closure, as more information emerges.

- At gate closure, market participants must submit their contract positions and Final Physical Notifications (FPNs) as at present.

- At gate closure, market participants are invited to submit bids and offers into their zonal Balancing Energy Market (BEM) auction, and then the BEM auction clears the forecast NIV. All cleared bids or offers are paid the BEM clearing energy price.

- Market participants are cashed out for the imbalance between their contracted position and metered output, at the single cleared BEM price.

- Post gate closure, the SO resolves any imbalances at least cost using pre-contracted response and the available (and as yet unused) pre-contracted reserve. The costs of these post gate closure actions are allocated via the information imbalance charge.

- The information imbalance charge could be allocated predominantly on the basis of metered ouptut vs gate closure FPNs, but a portion could be levied on metered output vs the within-day PN (to provide an incentive on accurate PNs that feed into the NIV).

- Reserve creation costs are flagged into the relevant future periods, and any system actions (minimised with full market splitting) would also need to be covered by pre-contracted reserve, with the costs then socialised.

6.3.4 We recognise that the SO will need access to balancing products to balance the system minute-by-minute post gate closure. Instead of having a post gate closure 'Balancing Mechanism' (as today), the SO can use pre-contracted reserve and response to resolve imbalances. This assumes that:

1) There is limited need for system actions in the BM given that market splitting has been implemented, and if there are residual constraints then these can be managed with reserves, and

2) The energy imbalance has already been resolved through the BEM based on the best forecast at the time.

6.3.5 These post gate closure actions are thus more related to 'fine-tuning' the energy requirement based on new information since the BEM.

6.3.6 We believe that a BEM designed in this way could bring significant benefits. Participants would be cashed out on the basis of a single marginal (unpolluted) cash-out price, which would be fully cost-reflective thereby incentivising an efficient level of security of supply through using flexible resources. Providers of balancing energy (in particular flexible resources such as supply-side, DSR and storage) would have access to a liquid hour-ahead exchange with a single clearing price. Even with the SO as the single buyer, the increased liquidity and transparency at gate closure could drive intra-day liquidity and competition in the market.

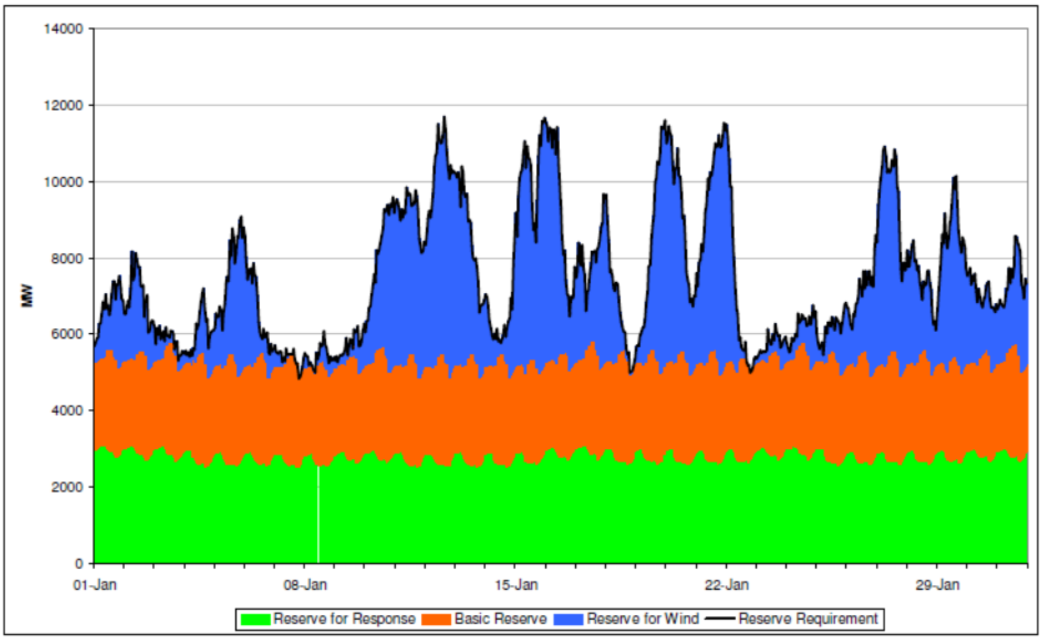
6.3.7 With balancing energy paid a marginal clearing price, the BEM auction could be used as the basis for the common merit order, in accordance with the EBFG.

6.4 Day-ahead reserve market

6.4.1 We believe that a day-ahead reserve market is an important part of this package, as it allows for the efficient separation of reserve as a distinct product from energy. It is also more in line with the EBFG, which requires harmonised reserve products and procurement as close to real time as possible, on a competitive basis.

6.4.2 The reserve requirement will fluctuate on a much more dynamic basis in future, as wind penetration increases. This is illustrated in Figure 5 from National Grid, in which the reserve for wind requirement in January 2020 is shown to fluctuate by up to 6 GW on a daily basis.

Figure 5: National Grid – Volatility of operating reserve requirement January 2020[19]



6.4.3 It therefore seems sensible to consider more dynamic reserve procurement arrangements that allow / require the SO to procure its reserve requirement on the basis of more accurate information about wind availability. This could lead to lower reserve costs overall, to the extent that more dynamic reserve procurement better aligns with the actual requirement. It would also create a liquid market for flexible resources to compete on a level playing field, which could attract new entrants, making reserve provision more competitive and driving down costs.

6.4.4 The option of a day-ahead reserve market was discussed at the final workshop. We understand that stakeholders (including National Grid) were not convinced that a case has been made for a change to the reserve procurement arrangements. However it is not clear that this option was considered in the context of a coherent package, nor whether stakeholders were thinking in terms of the future volatile reserve requirement.

6.4.5 Table 8 sets out the key design issues raised by Ofgem and commented on by stakeholders, as well as our observations.

[19] National Grid, 'Operating the electricity transmission networks in 2020', June 2011, p.53 (the analysis is based on NG's 'Gone Green' scenario). Available online at: http://www.nationalgrid.com/NR/rdonlyres/DF928C19-9210-4629-AB78-BBAA7AD8B89D/47178/Operatingin2020_finalversion0806_final.pdf

Table 8: Day-ahead reserve market – issues raised

Issue identified	Details	Wärtsilä observations
Who should be able to participate?	Ofgem presented three options: 1) One-sided auction with the SO as the single buyer of reserve 2) Two-sided auction in which both the SO and market participants could procure reserve to meet the requirement 3) Two-sided bilateral market for both the SO and market participants, with imbalance exposure reduced for participants that have procured reserve	Given the complexity associated with a two-sided market, we would suggest initially a one-sided auction with the SO as the single buyer of the reserve requirement. As the mechanism matures over time, and if market participants express an interest, a two-sided auction could be explored. There may be merit in the design that allows those market participants that have procured reserve to reduce their own imbalance exposure.
How would it interact with existing reserve and response procurement arrangements?	There is a question of what products would be procured through the day-ahead auction National Grid procures balancing services for a range of reasons – reserves (e.g. fast-start and STOR), and frequency response Given that some of these products are required on a constant basis, it may not be efficient or desirable to re-contract on a daily basis	The SO should retain the option to procure reserve and response in advance of the day-ahead auction, subject to an incentive to be economic and efficient Further, in accordance with the EBFG, reserve products need to be harmonised, and the volume of forward purchases under long-term contracts should be limited as far as possible Reserves contracted in advance could still be cleared through the DAH auction at the pre-agreed availability fee. Response (a different product) would not be cleared through the auction.
How should costs be recovered?	There is a question of how reserve availability fees and utilisation fees would be recovered if a day-ahead market is adopted	Utilisation fees could either be pre-agreed ahead of the reserve auction, or could become part of the auction process alongside the availability fee Reserve could either be called in the BEM, in which case the utilisation fee would be included in the BEM merit order. If reserve is called by the SO after gate closure the utilisation fee (and the cost of any other post gate closure actions) could be recovered via an information imbalance charge. Reserve availability fees could be included in BEM offers based on ex-ante expected usage, then recovered through cash-out (with the remainder socialised). See our proposed strawman below.

6.4.6 Taking onboard the design issues raised as part of the consultation, we would envisage that a day-ahead reserve market could work according to the following steps:

- The SO provides a forecast of demand and the reserve requirement at the DAH stage for the DAH reserve market in each market zone (post market splitting).

- Market participants are invited to submit offers into the DAH reserve auction, either at a pre-agreed utilisation fee, or the offer could be for a combined availability and utilisation fee. Forward-contracted reserve such as STOR would submit their pre-agreed offer parameters.[20]

- The auction clears with the SO having procured the daily reserve requirement. All cleared offers would be eligible to receive the cleared availability fee for each of the 48 settlement periods across the day (subject to MEL submissions).

- The availability fees would be allocated into the offers of reserve providers, either as a flat uplift or as a profiled uplift across the day based on expected usage. If the latter, the SO could communicate at the DAH stage the periods in which the availability fees would be allocated for the following day (e.g. allocate equally into 6 hour period between 2pm and 8pm).[21]

- The SO would automatically submit an offer to provide balancing energy at gate closure (into the BEM) on behalf of cleared DAH resources (subject to technical parameters on notice periods, ramping, etc), at the pre-agreed utilisation fee with uplift for the availability fee as defined.

- If reserve resources' offers are used to meet the NIV, they would be dispatched and paid the clearing price. Costs of cleared reserve would then be recovered through cash-out at the marginal BEM price.

- Post gate closure, the SO resolves any imbalances at least cost using pre-contracted response and the available (and as yet unused) reserve contracted through the DAH market. The costs of these post gate closure actions are allocated via the information imbalance charge (levied on inaccurate FPNs and PNs as per the BEM proposal above).

- Any remaining reserve availability fees not recovered through either cash-out or the information imbalance charge would be socialised.

[20] There would need to be incentives on the SO to be economic and efficient, so that an appropriate trade-off between DAH reserve and real-time balancing energy could be made. In particular it will be important for reserve availability fees to feed into balancing energy prices as accurately as possible.
[21] We note that while this will not perfectly allocate reserve availability fees into the relevant half-hour, allocation of daily availability payments on the basis of day-ahead expected usage would represent a significant improvement on both the current methodology and the allocation achievable under a narrow approach.

6.4.7 We believe that a day-ahead reserve market designed in this way could bring significant benefits. Initially, it could provide a price signal against which investments could be made. It could lower the barriers to entry for parties looking to participate in reserve because it would be transparent, predictable and requires less commitment than longer term products.

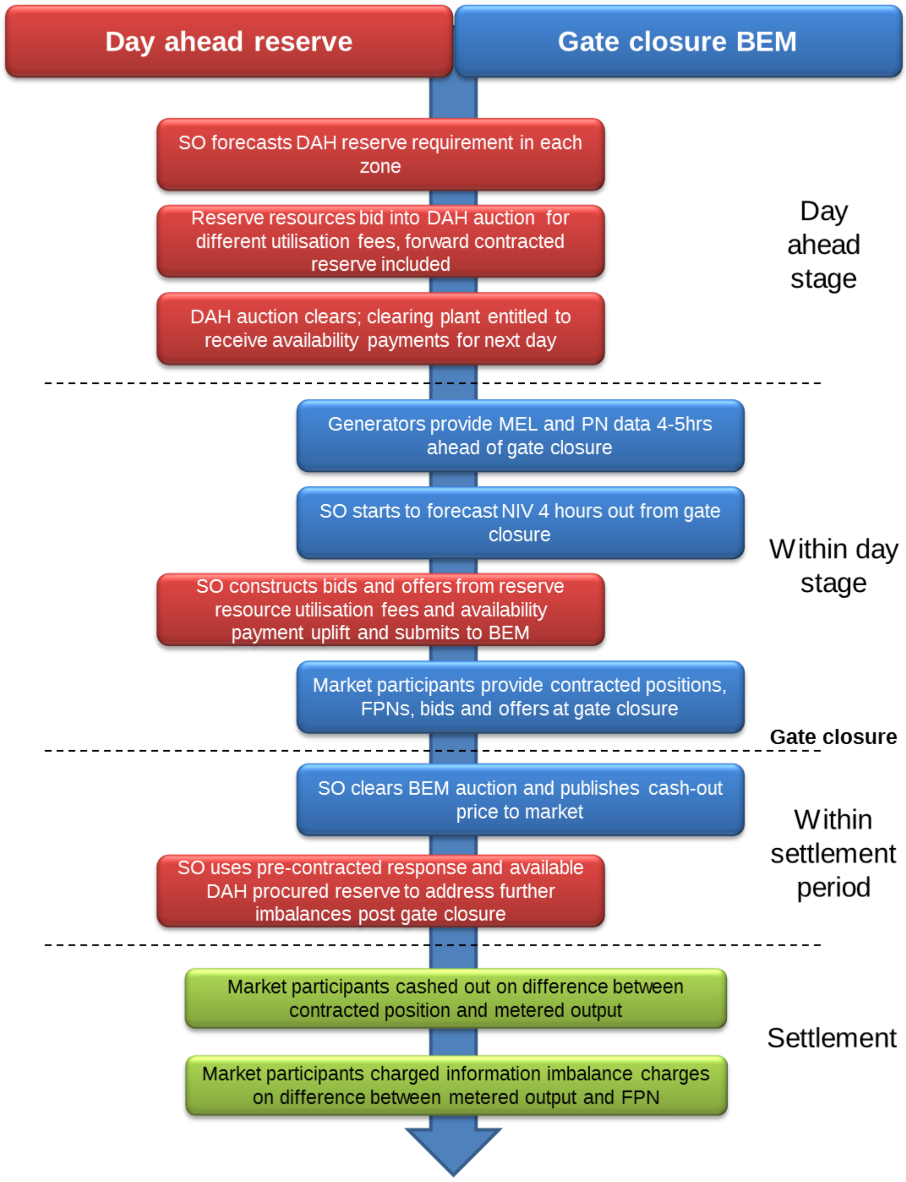
6.4.8 In the future as confidence builds, and depending on demand, it could offer the potential to turn into a two-sided market, where reserve could be traded as the option to increment or decrement energy at any point up to gate closure.[22] Further, reserve which is bilaterally traded in this way could be utilised by the SO with arrangements to make sure the 'buyer' of the reserve is either appropriately compensated or has its exposure to cash-out charges reduced accordingly.

6.5 Complete straw man of wider scope package

6.5.1 We present our complete straw man for the wider scope package in Figure 6 below.

[22] This may also be of interest to intermittent generators looking to manage their imbalance exposure themselves (i.e. without a PPA).

Figure 6: High level flow chart for balancing in a wider scope package



6.6 Assessment of the wider reform package against the SCR objectives

6.6.1 Our objective in this section has been to consider a coherent package of wider reforms that could best meet the SCR objectives. While we have not undertaken a thorough review of every design possibility, we believe that with further development this package of arrangements can fit together in a coherent way. We have taken into account the issues that Ofgem has put forward, the views of stakeholders, and provided our own views on what is practical.

Table 9 summarises our assessment of this package against the SCR objectives.

Table 9: Assessment of the wider scope approach against objectives

Objectives		Positives	Negatives	Overall assessment
Incentivise an efficient level of security of supply	Incentivise optimal level of investment (through appropriate price signals)	Firm interruption priced at VoLL should enhance investment signals Single marginal cash-out price through the BEM provides correct signals, and can drive an increase in intra-day liquidity	Complexity in establishing new market mechanisms to drive price signals for various products	
	Pay firm customers appropriately for the DSR service they provide if their demand is involuntarily interrupted	Firm customers compensated at VoLL for involuntary interruption		
	Incentivise plant flexibility and DSR	Day-ahead reserve market provides a transparent and liquid market for flexibility sources Single marginal BEM price can enhance signals for flexibility, and encourage greater market participation	SO as single buyer in day-ahead reserve market may restrict opportunities for bilateral options market	
Increase the efficiency of balancing	Minimise market distortions due to the need for the SO to balance the system	Market splitting allows cash-out price to much more reflective of 'energy-only'	There may be residual error in reserve cost allocation	
	Incentivise participants to balance their position as far as is efficient	Single marginal cash-out should provide strong incentives for participants to balance		
	Appropriately reflect the SO's costs for balancing in cash-out prices	Market splitting allows cash-out price to much more reflective of 'energy-only'	There may be residual error in reserve cost allocation	
Ensure our balancing arrangements are compliant with the EU Target Model and the EMR Capacity Mechanism (CM)	Align GB balancing arrangements with EU balancing and capacity allocation and congestion management framework guidelines	Allows a common merit order for balancing energy to be facilitated, priced on a marginal pay-as-cleared basis Day-ahead reserve market facilitates harmonisation of reserve products and competition in procurement close to real-time	Complexity in establishing new market mechanisms	
	Work closely with DECC to ensure cash-out arrangements and the EMR CM complement each other	Too early to comment		

6.6.2 In sum, we consider that this package of wider reforms better facilitates achievement of the SCR objectives. Fully marginal cash-out based on the BEM would meet the twin objectives of incentivising an efficient level of security of supply and increasing the efficiency of balancing. This package would be fully compliant with the EBFG, both in terms of the firm requirements as well as the general direction of travel. It would incentivise investments in the flexibility required in future with increased intermittent generation on the system, and could create the conditions for a more competitive, transparent and liquid market.

7 CONCLUSIONS

7.1.1 While we support the general direction of travel towards more 'market-based' and cost reflective electricity balancing arrangements, the fundamental question of whether a narrow or wide approach should be adopted as part of the review still needs to be resolved.

7.1.2 We have considered from the bottom-up whether more market based balancing arrangements can be delivered using a 'narrow' approach with the current Balancing Mechanism, or whether the practical difficulties are such that achievement of the SCR objectives may be undermined. Our observations are that:

- Fully marginal cash-out (PAR 1) may not be practically feasible given the residual uncertainty in system action flagging and reserve cost allocation. This may not meet the twin objectives of incentivising an efficient level of security of supply and increasing the efficiency of balancing.
- It does not appear that a pay-as-cleared pricing methodology could be adopted under the current BM (given that procurement takes place on a continuous bilateral basis rather than via an auction), and pay-as-bid for balancing energy would not be compliant with the current EBFG.
- More generally, we are not convinced that even a 'best case package' of reforms under a narrow approach could produce a set of balancing arrangements that would remain fit-for-purpose in the future with increasing intermittent generation on the system.

7.1.3 In our view the SCR objectives could be better achieved if Ofgem were to depart from the narrow approach and instead pursue new approaches to balancing. We have put forward a coherent package of reforms that attempts to overcome some of the practical difficulties under the narrow approach, as well as delivering more fit-for-purpose arrangements in future. The key elements of our proposed package are as follows:

- Market splitting to price the most material transmission constraints, so as to reduce the scope for system actions to distort the cash-out price

- A Balancing Energy Market held at gate closure to resolve a forecast Net Imbalance Volume based on a single marginal clearing price

- A Day-Ahead Reserve Market to allow the SO to procure its dynamic daily reserve requirement

- An information imbalance charge to target the costs of post gate closure actions

7.1.4 While we have not undertaken a thorough review of every design possibility, we have considered the detailed design issues raised as part of the consultation and developed what we consider to be a workable 'straw man'.

7.1.5 We consider that this package of wider reforms better facilitates achievement of the SCR objectives:

- Fully marginal cash-out based on the BEM would meet the objectives of incentivising an efficient level of security of supply and increasing the efficiency of balancing.

- This package would be fully compliant with the EBFG, both in terms of the firm requirements as well as the general direction of travel.

- It would incentivise investments in the flexibility required in future with increased intermittent generation on the system, and could create the conditions for a more competitive, transparent and liquid market.

8 RESPONSES TO INDIVIDUAL CONSULTATION QUESTIONS

8.1.1 This section sets out our response to each of the individual consultation questions posed in the document. It should be read in conjunction with our main response above.

8.1.2 **Do you agree with the approach and the proposed stakeholder engagement throughout the SCR?**

8.1.3 We welcome Ofgem's transparent approach to the SCR and ways of working to date. A highlight for us was the series of interactive stakeholder workshops which we found to be well organised and particularly useful in aiding our thinking. We also appreciated Ofgem promptly sharing the slide packs after these events, particularly as we were unable to attend all the sessions in person.

8.1.4 However, we think that Ofgem's proposed high level approach should also include a requirement to be 'objective based' so that these can be reflected upon as the detailed policy is developed. This is because we do not feel that the objectives for SCR were comprehensively discussed at the stakeholder workshops. As a result, we have concerns that the SCR could become misaligned with its objectives and rationale, especially as Ofgem develops its detailed policy options over the next few months. We also think that the integration of intermittent wind generation is one of the biggest drivers for reform to GB balancing arrangements, and that this needs to be incorporated within the SCR objectives.

8.1.5 We would welcome the opportunity to further discuss any of the analysis or points made in this submission as Ofgem develops its detailed policy options as part of its stakeholder engagement strategy.

8.1.6 **Do you have any evidence that you would like to submit that may be relevant for any aspect set out in this document?**

8.1.7 Please see the accompanying Modelling Annex which assesses the requirement for flexibility in the future GB electricity market and the potential value of Smart Power Generation (SPG) as one source of flexibility.

8.1.8 We analysed savings in reserve cost in BSUoS with flexible supply side capacity, by replacing 4.8 GW of CCGT capacity with 4.8 GW of Smart Power Generation (SPG). The introduction of SPG could reduce the reserve costs in BSUoS[23] by £381mn in 2020 in a Base Wind scenario, and by £545mn under a High Wind scenario. The value is mostly derived from mitigating the need to create reserve from already running plant in the BM, and despatching flexible SPG (standing reserve) instead.

8.1.9 **What is your view on the interactions between our considerations and aspects of the EU target model?**

8.1.10 There are strong interactions between the requirements set out in the EBFG and Ofgem's considerations for the Electricity SCR. Ofgem should consider the SCR as an opportunity to lead the way in aligning GB balancing arrangements with the European direction of travel so that they minimise the risk of future uncertainty for market participants.

[23] Reserve costs in BSUoS are the costs of the actions taken by the SO in the Balancing Mechanism to ensure reserve and frequency response requirements are met. Total costs of reserve in BSUoS were about £238mn in 2010/11 (about 43% of total BSUoS).

8.1.11 Some of the EBFG's specific requirements may be challenging to meet if Ofgem was to pursue some of the SCR reform options it has put forward. As we set out in our 'best case narrow scope' package in Section 5 of this submission, the requirement on TSOs to submit a pricing method based on pay-as-cleared is particularly problematic for most narrow scope options using pay-as-bid pricing for balancing mechanism actions taken over a continuous period of time. We also note other EBFG requirements such as the need to standardise and exchange products across a common merit order, and the push for short term reserve procurement.

8.1.12 Given these requirements and the challenges they cause with the narrower reform options set out by Ofgem, we believe the SCR objectives can be better achieved with a wider scope, structural review of the way balancing energy and reserve resources are procured in GB.

8.1.13 **Do you feel there are any further alternatives to the reform options presented under our primary considerations?**

8.1.14 We feel that the impact of potential market splitting should be considered as part of the SCR ahead of each of the primary considerations. This has the potential to change the rationale for the SCR considerations on the allocation of reserve costs in particular, and would assist in removing a large proportion of system costs from the respective cash-out prices in each zone, creating a cleaner 'energy imbalance' price.

8.1.15 **What other benefits or drawbacks can you identify for each of our primary considerations? Please provide any evidence you may have to support your position.**

8.1.16 We provide our assessment of a 'best case narrow scope' package in Section 5, representing what we think is achievable under a narrow approach, given stakeholder feedback at the workshops in September and October. Our best case narrow option approach constitutes:

- a compromise on a more marginal calculated price (PAR 100);
- a single cash-out price;
- no change from pay-as-bid pricing; costing
- non-costed actions and
- improving the targeting of reserve costs.

8.1.17 As we set out in Section 5, while this hypothetical package of reforms would represent an improvement relative to the status quo, it is not clear that it would meet the SCR objectives. More generally we are not convinced that such a package of reforms would remain fit-for-purpose in future with increased intermittent generation on the system. Our main concerns are:

- **Less than fully marginal cash-out**: as some stakeholders said during the workshops, the best case package would probably have to compromise on how marginal it makes the cash-out calculation, because PAR 1 could still be susceptible to system action pollution under current tagging and flagging arrangements. The compromise price may not meet the twin objectives of incentivising an efficient level of security of supply and increasing the efficiency of balancing.

- **Compliance of pay-as-bid pricing with the EBFG:** It does not appear that this package would be compliant with the EBFG, given that balancing energy in the current BM would need to be compensated on a pay-as-bid rather than a pay-as-cleared basis.

8.1.18 In comparison, we think the key benefit arising from the implementation of a wider scope option such as the BEM is the access it gives providers of balancing energy (in particular flexible resources such as supply-side, DSR and storage) to a liquid hour-ahead energy market with a single clearing price, which could drive intra-day liquidity, hedging activity and overall levels of competition in the market. Further, with balancing energy paid a marginal clearing price, the BEM auction could be used as the basis for the common merit order as required in the EBFG.

8.1.19 It is important that a coherent package is developed to provide a full range of balancing tools to the market. Therefore, for a BEM to generate a true energy-only price, market splitting will likely be required to structurally separate system actions. We also think that the day-ahead reserve market option should be made a primary consideration, to work alongside the BEM to cleanly separate reserve as a distinct product from energy. It is also more aligned with the requirements of the EBFG, which requires harmonised reserve products and procurement as close to real time as possible.

8.1.20 **Which of the reform options considered under each of our considerations do you believe would provide the most efficient balancing incentives and why?**

8.1.21 We believe the most efficient balancing incentives are created under our proposed wider scope package which comprises:

- Market splitting to price the most material transmission constraints, so as to reduce the scope for system actions to distort the cash-out price

- A Balancing Energy Market held at gate closure to resolve a forecast Net Imbalance Volume based on a single marginal clearing price

- A Day-Ahead Reserve Market to allow the SO to procure its dynamic daily reserve requirement

- An information imbalance charge to target the costs of post gate closure actions

8.1.22 The BEM produces a clean energy price for market participants to respond to, and it can be designed to produce a single pay-as-cleared price with marginal pricing to eradicate distortions caused by pay-as-bid with dual pricing. System actions are reduced through market splitting; and the reserve requirement is procured more dynamically from flexible balancing resources at day-ahead stage. The information imbalance charge (IIC) plays a key role in emphasising the importance of accurate information at BEM stage, and recovers the costs of reserve from those parties that have needed its services over the settlement period.

8.1.23 Our proposed package of options would interact as follows:

- The SO provides a forecast of demand and the reserve requirement at the DAH stage for the DAH reserve market in each market zone (post market splitting).

- Market participants are invited to submit offers into the DAH reserve auction, either at a pre-agreed utilisation fee, or the offer could be for a combined availability and utilisation fee. Forward-contracted reserve such as STOR would submit their pre-agreed offer parameters.

- The auction clears with the SO having procured the daily reserve requirement. All cleared offers would be eligible to receive the cleared availability fee for each of the 48 settlement periods across the day (subject to MEL submissions).

- On the settlement day, Generators to provide Maximum Export Limit (MEL) and Physical Notification (PN) data ~4-5 hours ahead of gate closure, and then the SO communicates demand and Net Imbalance Volume (NIV) forecast ~4 hours ahead of gate closure.

- At gate closure, market participants must submit their contract positions and Final Physical Notifications (FPNs).

- At gate closure, market participants are invited to submit bids and offers into their zonal Balancing Energy Market (BEM) auction, and then the BEM auction clears the forecast NIV. All cleared bids and offers are paid the BEM clearing energy price.

- The SO would automatically submit an offer to provide balancing energy at gate closure (into the BEM) on behalf of cleared DAH resources (subject to technical parameters on notice periods, ramping, etc) at the pre-agreed utilisation fee with uplift for the availability fee as defined. The availability fees would be allocated into the offers of reserve providers, either as a flat uplift or as a profiled uplift across the day based on expected usage. If the latter, the SO could communicate at the DAH stage the periods in which the availability fees would be allocated for the following day (e.g. allocate equally into 6 hour period between 2pm and 8pm).

- If reserve resources' offers are used to meet the NIV, they would be dispatched and paid the clearing price. Costs of cleared reserve would then be recovered through cash-out at the marginal BEM price.

- Market participants are cashed out for the imbalance between their contracted position and metered output, at the single cleared BEM price.

- Post gate closure, the SO resolves any imbalances at least cost using pre-contracted response and the available (and as yet unused) reserve contracted through the DAH market. The costs of these post gate closure actions are allocated via the information imbalance charge.

- The information imbalance charge could be allocated predominantly on the basis of metered output vs gate closure FPNs, but a portion could be levied on metered output vs the within-day PN (to provide an incentive on accurate PNs that feed into the NIV). Any remaining reserve availability fees not recovered through either cash-out or the information imbalance charge would be socialised.

- Reserve creation costs are flagged into the relevant future periods, and any system actions (minimised with full market splitting) would also need to be covered by pre-contracted reserve, with the costs then socialised.

8.1.24 **Alongside this initial consultation we have published preliminary analysis of the last modification to the cash-out arrangements, P217A. Do stakeholders agree with the initial findings of this analysis?**

8.1.25 The P217A analysis has provided a valuable insight of the impact that system costs would have had on the cash-out calculation over the two year period without the P217A flagging methodology. It is clear that the inclusion of system actions in the cash-out calculation risks distorting cash-out prices away from a clean price for balancing energy in certain periods, so there is certainly merit in continuing the effort to flag and tag system actions away from the cash-out price calculation.

8.1.26 Participants at the stakeholder events in September and October appeared sceptical about the margin of error in the flagging methodology and its impact on prices if the Electricity SCR was to make the price calculation more marginal. There is a possibility of a failure in the flagging methodology aligning with the acceptance of expensive actions taken for system purposes which could expose market participants to extreme imbalance risk.

8.1.27 We understand other industry stakeholders' concerns, though we would caution against these stakeholders' suggestions that the SCR should mitigate this risk through compromising on how marginal the cash-out it makes the price calculation. In our view, this approach tries to address one imperfection with another. It is better to address the fundamental issue within the structure of the BM – that it procures a mixture of products under different pricing over a continuous time series – by pursuing a more structural reform through SCR using the wider scope options.

8.1.28 The wider scope reform would also mitigate other concerns over the 'side effects' of a more marginal price, such as higher redistribution through RCRC. It is feasible for imbalance charges from the pay-as-cleared BEM to be used to totally target the costs of balancing to imbalance parties only, which would remove the need for RCRC.

8.1.29 **What additional analysis could be done as part of the SCR around Modification P217A and the flagging methodology it introduced?**

8.1.30 To assess the rationale for market splitting, National Grid and Ofgem may be able to use the data compiled under P217A alongside that collected previously to assess the extent to which the volume of flagging actions might have reduced over the same period of time if the market had been split across the Cheviot boundary (see large Cheviot boundary management costs in Figure 4 in section 6 above). We also support participants' suggestions at the stakeholder workshops to analyse the extent to which PAR 100 would even reflect more than a single BMU to inform the debate over how marginal to make the cash-out price calculation.

8.1.31 **Do you agree with our rationale for considering making cash-out prices "more marginal?**

8.1.32 We agree. Cash-out prices should be fully cost reflective, based on the marginal value of energy in a given half hour. Without this, there may be inadequate incentives to invest in the flexibility required to manage the system with a high penetration of intermittent generation.

8.1.33 Investments in flexible resources factor their expectations of short term price fluctuations into their business case, as this is where their product delivers key value. If prices at these times are dampened down from being marginal, then this will impact decisions to invest in these resources.

8.1.34 **Do you agree with the circumstances we have identified in which the secondary considerations are important?**

8.1.35 We do not agree with all of the circumstances identified, as we think that the following secondary considerations should be identified on the same level as primary considerations, or investigated as part of a package:

- **The (day-ahead) reserve market** alleviates concerns around the long term misallocation of reserve costs into the energy price, allows energy and reserve costs to be more cleanly split, and is consistent with the provisions of the EBFG.

- **Improved provision of information** is key for market participants to be able to engage with cash-out prices, especially under narrower options for review where outturn prices are only likely to be known after the event.

- **Information imbalance charges** could reinforce the credibility of the information provided by participants, and will be increasingly important as levels of wind on the system increase. In the body of this response, we also propose that they are also a means to recover part of reserve costs used to balance parties who submit incorrect information into the BEM.

8.1.36 Do you have any other comment on the secondary considerations presented here? Please provide any evidence you may have to support your position.

8.1.37 As we set out above, we caution against considering these options as ‘second order’ to those labelled as secondary because some have the potential to offer a complete balancing package alongside primary considerations, such as market splitting, the day ahead reserve market and an information imbalance charge. Rather than splitting in ‘primary’ and ‘secondary’ considerations, it may be preferable to think in terms of coherent packages.