1. **How can Ofgem ensure that sharper Cash Out incentives from the Significant Code Review:**

   - **encourage generators and suppliers to balance their own positions before gate closure, thus reducing the call on National Grid to perform balancing activity after gate closure;**
   - **minimise the level of payments required under the capacity market; and**
   - **do not restrict market participation to major utilities?**

As a package, the Electricity Balancing Significant Code Review (EBSCR) policies have been designed to improve incentives on market participants to balance their positions by strengthening the price signal for cash-out. However, a number of inefficiencies have been identified in the current arrangements which these reforms seek to resolve. In particular, EBSCR seeks to improve the extent to which the price that a party is exposed to for a given imbalance position captures the value of that imbalance to the System Operator (SO) in its role of taking actions to maintain a balanced Transmission System. More marginal cash-out prices, introducing costs for demand control actions and changes to how reserve actions are priced into cash-out will make the prices sharper for those parties whose imbalance has contributed to that of the Transmission System, particularly in times of system stress. Conversely, the single imbalance price[1] reflects the positive value that an imbalance position in the opposite direction to that of the Transmission System provides to the SO by helping to correct the System imbalance.

The Key recommendations provided in the National Audit Office (NAO) Electricity Balancing Services document (Fig. 20) outlines the proposals under the EBSCR Draft Policy Decision. We agree with Ofgem's approach and the direction in the EBSCR Final Policy Decision (FPD)[2] which is broadly consistent with these, with two main exceptions. Firstly, rather than moving directly to basing cash-out prices on the most expensive balancing action taken by the SO, Ofgem have instructed a phased reduction in the weighted average volume of balancing actions to reach this level by winter 18/19. Secondly, the payments to domestic and small business customers for demand disconnection have been removed.

<u>Incentives on generators and suppliers to balance their own positions</u>

Three of the EBSCR reforms will sharpen the cash-out price. From winter 14/15 the imbalance price will be calculated based on a more concentrated weighted average volume of the most expensive actions. This volume weighting will reduce in a phased approach to winter 18/19 when the price will be set based on the marginal (most expensive) balancing action. Furthermore, changes to the way in which reserve actions taken by the SO are priced into cash-out and the introduction of an associated price for Demand Control actions ensures that the imbalance price has the potential to reach higher levels for parties who have short positions at times of system scarcity. These reforms increase the potential level of prices faced by those market participants whose imbalance positions extend the imbalance of the Transmission System. The potential for higher prices increases the costs associated with imbalance, thereby incentivising market participants to take sufficient actions (e.g. dispatching additional units or buying in the spot market) prior to the closure of the market (gate closure) for each Settlement Period to mitigate their imbalance risks and ensure that contracted positions are as accurate as possible against their metered outturn. This in turn should minimise the number of energy balancing actions that National Grid has to take post gate closure

[1] For each Settlement Period, market participants will be exposed to a single cash-out price for their imbalance based on the pricing calculation methodology used to capture the costs of balancing the system. Under existing (dual pricing) arrangements a second methodology is used to approximate the market price parties might have received had they traded their imbalance position ahead of Gate Closure. This price is applied to imbalance positions that are in the opposite direction to the Transmission System.

[2] Ofgem EBSCR Final Policy Decision https://www.ofgem.gov.uk/publications-and-updates/electricity-balancing-significant-code-review-final-policy-decision

Impact on payments under the Capacity Market

Both in terms of the incentives on behaviour and the timing of implementation of changes, the EBSCR reforms have been designed to be complementary to the arrangements set out for the Electricity Market Reform (EMR) Capacity Market (CM). As outlined in the FPD, the CM delivers a secure revenue stream to support investment in reliable capacity to ensure peak demand for electricity can be met. Sharpening the cash-out signal strengthens the incentives for fast responding capacity by allowing higher rewards to capacity that can respond quickly when impending system tightness is signalled (e.g. by the new reserve scarcity pricing). The final phases of implementing the EBSCR reforms are set to be undertaken by winter 2018/19, in line with the first anticipated delivery year for the CM.

Section five of the FPD outlines Ofgem's view on the interactions with the CM. We would anticipate the sharper cash-out signals resulting from EBSCR reforms to reduce the CM auction clearing price, which determines the capacity payments, to a lower level than it would otherwise be. Access to higher prices at times of system stress, and the consequential impact on wholesale power prices, gives all market participants (those with and without a capacity agreement) an increased incentive to deliver electricity. This reduces the potential for, and impact of, stress events and so would reduce the penalty exposure of any provider failing to deliver. This reduction in risk should be reflected in lower bids being submitted to the auction. By incentivising changes to market participants' behaviour in response to increased imbalance risk, wholesale market prices may potentially increase; increasing the revenue available in the wholesale electricity market should result in lower capacity bids.

The impact of Electricity Balancing Significant Code Review on market participation

The inclusion of single pricing in the package of EBSCR reforms resolves one of the inefficiencies of the existing cash-out arrangements. By settling market participants on a single imbalance price, those market participants whose imbalance positions reduce that of the Transmission System as a whole (by being in the opposite direction) are effectively rewarded by a better price than they would receive under dual pricing. Hence, whilst there have been concerns expressed from industry that small parties may be more exposed to potentially higher imbalance costs due to EBSCR, the single pricing policy helps to alleviate this impact. Results of analysis on distributional impacts of the EBSCR package summarised in section 4 of the FPD, demonstrate that in the case of small parties, the beneficial impacts of the single pricing policy offset the potentially disadvantageous impacts of sharpened imbalance prices. The analysis concludes that there is not a disproportionate risk for parties as a result of EBSCR and, therefore, that negative impacts on market participation as a result of the policies are not anticipated.

2. To what extent can National Grid's use of the two new balancing services tackle the risks to security of supply identified in Ofgem's 2013 capacity assessment?

In June 2013, Ofgem published their Capacity Assessment Report which highlighted a narrowing of capacity margins in the mid-decade period and identified that the de-rated capacity margin for winter 15/16 would be just sufficient to meet the Government's proposed security standard of three hours Loss of Load Expectation (LoLE). It also identified a number of sensitivities where the de-rated margin could drop below that level for both winter 15/16 and winter 14/15.

Given the limited time between this assessment and these periods of risk, it would not be possible to build any new generation that was not already in construction and so the mitigating options for these sensitivities are either to reduce the level of demand over the winter peak, or to be able to access existing generation that would otherwise be unavailable. In response, National Grid developed, and had approved by Ofgem, two additional system balancing tools consisting of a Demand Side Balancing Reserve (DSBR) and a Supplemental Balancing Reserve (SBR) that could be used as a last resort measure in the unlikely event of a shortfall of generating capacity.

Following an extensive industry consultation, we have been working closely with Ofgem to agree a methodology by which we calculate any volumes required from these two services. We have also conducted an “expressions of interest” survey in which a number of generators and demand side providers have indicted their willingness to participate in these services. The outcome of the volume methodology calculations and the expressions of interest indicate that for the coming winters, sufficient volumes of both DSBR and SBR can be procured to maintain security of supply at the same level as seen in recent years. We may see some movement between Short-term Operating Reserves and the new mid-decade product markets over the next few years as providers find the market that best suits their business drivers.

3. To what extent can implementation of the EU Third Package and the Target Model reduce balancing costs and mitigate risks to security of supply?

The EU Third Energy Package aims to establish an open, integrated and competitive energy market across the European Union. The Target Model establishes common rules to facilitate efficient use of cross-border capacity and encourage harmonisation of European wholesale market and balancing arrangements. The main features of the Target Model are:

- **Day-ahead market coupling and continuous intraday trading**: This will mean that the GB day-ahead price will be calculated at the same time and same way as prices in neighbouring markets. Intraday trading will also help generators and suppliers to balance their positions as the accuracy of their forecast generation and demand improves closer to real time. GB is already market-coupled at day-ahead via its membership of the ‘North-West Europe’ pilot early-implementation project, which went live on 4th February 2014 and accounts for more than 75% of the total electricity consumption in Europe.
- **Electricity balancing**: The Target Model includes a framework for developing cross-border balancing markets. The potential for balancing resources to be effectively shared and traded between countries can enhance security of supply, improve the levels of competition in balancing markets and reduce the costs of system operation.
- **Long-term transmission rights**: The Target Model mandates the development of cross-border markets for long term rights to access capacity on interconnectors. This could benefit GB market participants and reduce balancing costs through providing access to wider markets.

The key areas to focus on from a balancing cost perspective are the development of cross-border balancing markets and the establishment of appropriate incentives on market participants to balance their contractual and physical positions as market timeframes transition into balancing timeframes. This is to be achieved via the European network code on Electricity Balancing.

The European network code on Electricity Balancing aims to promote greater integration, coordination and harmonisation of electricity balancing rules in order to make it easier to trade resources cross-border. This will allow National Grid and other Transmission System Operators (TSOs) to use available resources more effectively, and in doing so, drive efficient balancing costs and promote security of supply through diversification. It also aims to move Europe from its current model in which most of the system balancing is carried out on a national level, to a model in which larger markets allow Europe’s diverse available sources to be used more effectively (for example flexible, fast-acting hydro power from Continental Europe facilitating integration of increasing levels of wind generation in Great Britain).

To maximise the potential for National Grid to benefit from cost-effective balancing resources in Europe, it will be important to co-operate closely with neighbouring Transmission System Operators (TSOs) to ensure efficient use of any cross-border capacity that remains available after the conclusion of forward, day-ahead and within-day market processes. National Grid is fully engaged in the work to develop the necessary products and services to make best use of such residual capacity for balancing purposes.

It should be noted that, as the Target Model seeks to facilitate efficient use of cross-border capacity through the timescales, it is possible that available capacity is fully utilised in advance of balancing timescales. With this in mind, one of the aims of the European network code on Electricity Balancing is to enable the market for pure energy to be aligned with markets for balancing services such that, in advance of balancing timescales, cross-border capacity can be assigned to the products that provide the greatest social benefit. Therefore by linking to other countries' transmission systems National Grid can increase the diversity and security of energy supplies and facilitate competition in the European market.

Notwithstanding the development of the European network code on Energy Balancing, it remains important for the GB market and balancing arrangements to support efficient balancing activity at a domestic level. National Grid continues to engage with industry to develop its own balancing services; and support wider initiatives such as Ofgem's Electricity Balancing Significant Code Review.

4. **To what extent will the 2013-21 regulatory settlements for Transmission Owners (RIIO-T1) address constraints on the movement of electricity around Great Britain?**

RIIO-T1 fully addressed the constraints on the movement of electricity around Great Britain, balancing the costs to consumers of investment in additional transmission capability versus the costs of congestion. The processes and levels of investment in the transmission system to facilitate the movement of electricity were subject to wide stakeholder engagement under RIIO-T1.

For Transmission Owners (TO) there was a baseline of capital allowances for load related investment. For significant investments in transmission capability (greater than £500m in the case of National Grid) Ofgem introduced a Strategic Wider Works process. This requires Transmission Owners to prepare a needs case that justifies the new capability required, the range of options considered and takes in to account the views of stakeholders. The cost benefit analysis required in the need case includes the assessment of the level and cost of congestion assessed against the costs of the proposed investment. This need case is scrutinised by Ofgem and their consultants to ensure the TO has sufficiently demonstrated the investment is in the best interests of consumers.

National Grid in our role as System Operator assists the Scottish Transmission Operators in producing supporting information for their needs cases and when requested provides Ofgem with additional information. For National Grid as TO in England & Wales there is a further mechanism introduced in to the Licence called the Network Development Policy that covers significant investments in boundary capability that is less than £500m. This is an annual process that National Grid runs for England & Wales where the generation and demand scenarios developed under the Future Energy Scenarios (FES) are accessed for their impact on the Transmission System. The assessment looks at the major transmission boundaries and any requirement for an increase in capability. Where an increase may be required the costs and time to deliver a number of potential solutions are assessed. This can include commercial solutions such as contracts with generators as well as assets solutions such as new overhead lines.

The potential solutions are subject to a cost benefit analysis that compares the transmission reinforcements to the potential costs of congestion under the different scenarios. This assessment uses an agreed "least regrets" methodology that was included in the RIIO-T1 consultation process. The purpose of the least regrets methodology is to balance the potential stranding or underutilisation of early transmission investments against the risk of incurring higher congestion costs if investment is delayed. In this way National Grid can demonstrate that the outcome of Network Development Policy balances cost to consumers of too early an investment against the costs to consumers of higher operating the network costs. This process also considers in-flight projects to ensure that if they are no longer required they are stopped.

This transparent process includes publishing the details of transmission boundary requirements, the range of solutions considered, the least regrets assessments and projects that are being started, continued with and those that are being stopped. The outcome of the Network

Development Policy is published in November each year in the Electricity Ten Year Statement. This is open to consultation as well as the annual assessment by Ofgem. The network data, the congestion cost assumptions and a version of cost benefit analysis tool used are also published. The same assessment process applies to Strategic Wider Works mentioned above.

These open and transparent RIIO-T1 processes, scrutinised by Ofgem, ensures that the constraints on the movement of electricity around Great Britain are kept under constant review and the decision on timing of investments balanced against congestion costs are made in the best interests of consumers.

5. **Is public information about constraint costs adequate, in the light of recent media publicity surrounding the scale of constraint cost payments to wind farms?**

We believe that there is currently a large amount of information published in respect to the scale of constraint payments. We report on all of the actions at a Balancing Mechanism Unit (BMU) level on reports and since January, we began to publish the total constraint payments by fuel type so as to provide a comparative basis between the fuel types, which itself was a response to customer feedback. We are of course always happy to receive feedback from customers and to consider making any additions to the level of reporting that is currently provided.

6. **How do you ensure that "Connect and Manage" is achieving its objectives without adding disproportionately to constraint costs?**

The current approach to ensure "Connect and Manage" is achieving its objectives, while considering the impact on constraint costs, is to monitor both forecast and outturn constraint costs, regular application and review of the Network Development Policy (see previous answer to question 4) and through infrastructure development and the delivery of a commercial strategy to minimise the outturn Balancing Cost may result in reduced constraint costs. We believe this approach is undertaken in a transparent manner with the publication of regular updates in the Quarterly Connect & Manage Report on the National Grid website. This is also discussed ahead of publication with Ofgem and the Department of Energy and Climate Change.

7. **How do you ensure that the approach to regulating balancing costs gives strong incentives for efficiency, while eliminating costs considered to be outside of National Grid's control?**

We are incentivised to maintain a strong focus on reducing balancing costs through the Balancing Services Incentive Scheme. Whilst costs are not always fully controllable, the scheme is designed in such a way to ensure that National Grid focuses on those activities over which it has partial or substantial control. For those elements that cannot be influenced directly by National Grid, incentives are structured to ensure that an appropriate level of focus is maintained and that innovative approaches to managing these costs are rewarded. For example, in respect to constraint cost, rewards under the incentives can only be realised if National Grid reduces costs by a minimum of 38% against the minimum approach of managing constraint issues in real time. This ensures that attention is targeted around outage placement, contracting strategies, in addition to designing and implementing competitive and innovative tender structures and services to help manage costs. In regards to those costs areas where National Grid has less influence, incentives still remain to reduce costs, albeit with a lower expectation of relative outperformance. Importantly, National Grid’s incentives are directly aligned with the interests of consumers.

8. **Are current arrangements for balancing services as a whole fit for purpose in the light of current and future developments (including the growth of intermittent and embedded generation)?**

In order to balance supply with demand and to ensure the security and quality of electricity supply across the GB Transmission System we procure a range of balancing services, such as; fast reserve and short term operating reserve, frequency response and inertia services, reactive (voltage support) services and constraint management services. All of which are provided by a range of providers including Balancing Mechanism (BM) participants, non-BM participants and interconnectors.

How much we need of these services has changed over the last five years and we forecast this to continue to change in light of future developments. The services themselves are closely aligned to how we keep the system secure, so, in general, we expect little change in the existing service specification. We expect;

- The volume of actions to manage energy imbalance to reduce with the implementation of the measures from Ofgem's Balancing Significant Code Review.
- Our reserve levels to increase with increasing volumes of embedded and intermittent generation
- Our frequency response requirement to increase, following the change in the Security and Quality of Supply Standard (SQSS) in April 2014 allowing an increase in the largest in-feed loss
- Our reactive (voltage support) requirement to increase with the changing pattern of generation and the decline in the national reactive demand
- The volume of constraint management services to increase in the short term as investment in the transmission system is carried out in parallel with connection of new generation

However, system inertia is an example of where balancing services are evolving to reflect changing system characteristics. With the increasing volume of asynchronous generation (mainly interconnectors and wind farms) - system inertia is proportionally lower than would otherwise have been the case. System inertia acts to slow down the rate of change of frequency following large demand or in-feed losses. This interacts with the frequency response requirement and is effectively also a new balancing service requirement due to the interaction with embedded generator's "Rate of Change of Frequency" (ROCOF) relays which protect them against islanding. The effect on our frequency response requirement could be mitigated by introducing faster frequency response and / or by new inertia services to limit the rate of change should it be necessary. We are working on developing both of these with the industry.

We continue to work to develop deep, liquid markets through which to procure balancing services and work to minimise barriers to entry to potential new service providers and work to provide them access to the markets for these services. This includes work in the Short Term Operating Reserve market, the Firm Frequency Response Market and bilateral negotiations and contracts for all balancing services where we can reduce costs.

9. How is Ofgem proposing to take forward the various workstreams, other than locational pricing, identified by the Future Trading Arrangements initiative?

Future Trading Arrangements (FTA) is an Ofgem led initiative that was launched in 2013 to review the wider impacts of a number of ongoing policy developments on the GB trading arrangements including EMR, renewable targets and implementation of the EU Target Model. Following a number of industry working groups and higher level industry forums held in the second half of 2013, Ofgem proposed four work streams for further focus. These being;

- **Locational pricing:** driven by a requirement in the Capacity Allocation and Congestion Management (CACM) Network Code to report periodically on bidding zones;
- **Managing intermittency by market participants:** to consider additional measures for managing uncertainty (e.g. wind) near real time;
- **Ancillary services, balancing and reserve review:** review current procurement mechanisms and propose additional services (e.g. cross border) given anticipated system operation challenges; and
- **Longer term market arrangements:** this would run in parallel with the above work streams and serve to ensure that shorter term policy remains consistent with a longer term vision.

Ofgem issued an open letter to the industry in February 2014 setting out their plans for the following six months. This letter confirmed that, as agreed with industry members, the locational pricing work stream would be taken forward as a priority in 2014, with initial work being presented at the next FTA Forum scheduled in July. The letter also stated that Ofgem would share its thinking on how the other three work streams should be taken forward at the next Forum which is scheduled to take place on the 4th July 2014.