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Dear Sirs

Energy Market Investigation: Updated Issues Statement

Thank you for the opportunity to respond to your Updated Issues Statement document. We have summarised our views in Appendix 1, attached to this document. This response is not confidential.

Yours faithfully

Mark Tomlinson
Senior Counsel

<u>Appendix 1 – Response to Updated Issues Statement Theories of Harm 1 and 5</u>

We offer observations from an operational viewpoint which we hope are relevant to the topics highlighted in the Updated Issues Statement concerning Updated Theories of Harm 1 and 5.

Updated Theory of Harm 1: market rules and regulatory framework

<u>Central vs Self-dispatch</u>

In addition to the points made in paragraphs 35 to 40 of the Statement, it may also be relevant to note the ongoing developments of the European market arrangements, especially in respect of improving the capability of interconnection between GB and mainland Europe and the use of this capability to meet day ahead and within day market needs. Such developments have the potential to further improve transparency and liquidity of short-term markets without having to compel parties to bid in central arrangements.

<u>Imbalance cash-out – the PAR volume</u>

The first issue identified in paragraph 44 of the Statement alludes to the risk that PAR1 could introduce noise into the imbalance cash-out price signal rather than providing a representative marginal cost of balancing energy for that half-hour. Such noise would give rise to a risk that some parties might incur additional costs in order to manage it. In this context it is important to note the effect of the Continuous Acceptance Duration Limit (CADL) flagging and De Minimis tagging in helping to remove potential sources of such noise (the current values of these measures have been used by Elexon and Ofgem when calculating their respective historical assessments of how imbalance prices might behave under EBSCR arrangements).

However when considering whether larger PAR volumes would be beneficial as a means of minimising potential noise (or mitigating potential market power issues identified as the second issue in paragraph 44 of the Statement) it is important to consider the effect that such a price averaging 'filter' could itself have. An averaging filter will produce imbalance price signals which lag the spot prices the system operator will accept. For example, in an approaching scarcity event, when the system operator will need to buy at prices further up the offer supply curve, under higher PAR volumes it will be possible to predict that imbalance prices will be generally lower than the prices of the most marginal offers accepted for energy reasons. The presence of such a lag could produce unhelpful incentives for flexible plant to accept imbalance on their contracts so that they can access better prices by participating in the Balancing Mechanism (BM). For example, approaching a scarcity period, a provider of flexible capacity might benefit financially if they reduce their Physical Notifications, paying the lower imbalance price on their unmet contracted positions, and receiving a higher BM offer acceptance price (which they may be confident of receiving in such periods). Such behaviour would be undesirable because it would increase system operator BM buy volumes during high work load, security critical periods and may increase uncertainty concerning the actual system imbalance in the approach to scarcity periods. Furthermore, whilst we would hope that the duty to make accurate Physical Notifications (under the Grid Code) should provide some assurance of reliability in the information submitted to the system operator, this scenario may increase the potential for greater volatility in those submissions.

In practice, the commercial risks associated with deliberately incurring imbalance exposures for somewhat uncertain gains could be expected to mitigate the risk of such behaviours. Nevertheless, given the potential for an increasing number of predictable price spread opportunities (for example, as a result of wind lulls) it is important that all these factors are considered when selecting a suitable compromise value of the PAR level.

In relation to the concern that a single party may know they will be the price setter and determine the imbalance price for a given Settlement Period (i.e. the second point in paragraph 44 of the Statement), the Net Imbalance Volume (NIV) tagging element of the imbalance price calculation would in practice help mitigate this risk because any attempt to increase an offer price (or reduce a bid price) in the BM may result in the price of the action being removed from the energy imbalance price stack. This would limit the extent that any individual could know that they will set the imbalance price.

Imbalance cash-out - Risk of Double Payment for Scarcity

Concerning the issues relating to Reserve Scarcity Pricing (RSP) in paragraph 45 of the Statement, we note that the risk of over rewarding capacity providers is not solely due to the proposed RSP mechanism but could arise whenever elevated energy market prices results from scarcity. If capacity is purchased in the Capacity Market (CM) to meet a LOLE = 3 hours security criterion then, in theory and under static conditions with known demand response, it could be expected that there will be approximately 3 hours on average per year in which contracted capacity would be insufficient. If short-term energy prices reflect consumer willingness to pay for supply in these periods then CM contracted generation correctly operating at this time might receive both the competitive price for capacity plus energy scarcity prices (depending on the nature of their contracts or imbalance). The issue of potential double payment would therefore seem to be wider than the effect of RSP and would be expected to become more prevalent as measures strengthen the signalling of scarcity in imbalance and hence energy prices more generally.

In other markets with capacity mechanisms, we understand this issue is explicitly addressed. For example, in New England, when energy prices exceed a threshold reflecting short-run marginal fuel costs, a Peak Energy Rent (PER) adjustment is made to the capacity payments that otherwise would occur. However, we understand that development of an equivalent mechanism for the GB market was not pursued due to the problem of identifying the extent to which particular capacity providers will have benefited from such rents given their particular energy contracts.

To encourage efficient market behaviours and address circumstances not foreseen when capacity was procured, we support measures that strengthen the appropriate signalling of scarcity in energy prices including cash-out prices in particular. The suppression of such prices would reduce the effectiveness of market signals to flexible generators, responsive demand, storage facilities and interconnectors. As GB may well move towards having more variable production and more interconnection it is important to ensure that market arrangements allow price signals to accurately reflect prevailing system conditions and therefore the value of short-term flexibility which also drives efficient interconnector despatch. On this basis, policy should generally not act to limit the signalling of scarcity in energy prices but rather should keep the nature of capacity payment under review.

Specifically concerning the balance of issues surrounding the RSP proposal, we are concerned about the present short-comings of the Buy Price Adjuster (BPA) mechanism which may mean that STOR costs are not accurately reflected and might contribute to missing money for providers of short-notice flexibility and potentially contribute to imbalance price noise (at times of adequate system margin, when STOR represents the most efficient balancing action). We suggest, therefore, that the assessment of RSP should include consideration of whether it improves on the present status quo of including the current BPA in imbalance prices.

Locational price signals for constraints and losses

The assessment outlined in paragraph 48 of the Statement, which would weigh the efficiency gains from improved locational prices against the practical and distributional impacts of their introduction, is similar to that required when considering revision of European market price bidding zones which is now a requirement of the EU Capacity Allocation and Congestion Management (CACM) code. We understand that a pilot study is now underway to consider the case for new price zones in the current single price area for Germany and Austria. Waiting for the outcome of this Pilot Study before progressing work in GB would have significant timescale implications, but could allow any assessment to benefit from the deeper understanding gained from these European processes and ensure better alignment to them.

A GB specific issue that has previously arisen, both in considerations of proposals under the Balancing and Settlement Code to introduce locational loss factors and proposals under the Transmission Access Review to introduce a locational Balancing Service and Use of System (BSUoS) charge to reflect constraint costs, is the potential interaction of new locational signals with those already present in the Transmission Network Use of System charge (TNUoS).

A view expressed by a number of market parties was that just one instrument to provide a long-run marginal cost signal is required in GB and, as TNUoS already fulfils this function to some degree, then the addition of further elements (such as to address short-run constraint and loss costs which might cause an overstatement of differentials already in TNUoS), should be avoided. Comparing with systems (e.g. in New England, the PJM area, Texas, etc) which provide real-time Locational Marginal Prices (LMPs), network users who want certainty about their locational exposure purchase transmission access instruments[1]. Such users would generally expect the payment for this instrument to exempt them from the short-run LMP exposures they would otherwise incur by default. The Secretary of State's decision following TAR to impose a licence condition on the system operator to prohibit additional constraint based charges might be taken to be government's agreement with this 'single instrument' approach. However, TNUoS locational differentials are currently only reflective of network investment costs albeit these will address, amongst other things, network constraint and loss issues that would otherwise occur. Following such investments, residual losses and congestion will be expected to endure and these are neither signalled in locational charges nor discovered, as in the case of gas entry and exit access right auctions. The refinements resulting from Project TransmiT do not affect this position. On this basis, the development of arrangements to better signal the cost of constraints and losses in GB must also address the implications for the TNUoS methodology and long-run access arrangements.

To facilitate transparency in consultations on cost-benefit analyses[2], National Grid intends to improve the public domain tool which permits users to explore how electricity system development scenarios might operate. The improvements will better represent interconnectors and the interactions between GB and other European markets. The revised tool provides shadow costs of network limitations and losses which can be aggregated to provide indicative long-run signals. Although we have a number of data release permissions and model validation tasks still to complete, we would be pleased to offer initial results which would help illustrate the effect of loss signals in GB given potential interactions with adjacent markets via interconnection.

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[1] These instruments can take the form of either 1) a Financial Transmission Right (FTR) which returns congestion revenues that result from the difference in price between the locations of production and consumption; or 2) a Physical Transmission Right (PTR) which permits trades to occur as if production or consumption are at the same location.

[2] This is required as part of our enhanced system operator duties identified under Ofgem's Integrated Transmission Planning and Regulation (ITPR) Project which examines the merits of significant network and interconnector developments.

Updated Theory of Harm 5: broader regulatory framework and code governance

Two fundamental issues (paragraph 194 of the Statement) have been identified with respect to the current regulatory arrangements, we set out our thoughts on these below.

Does the number of codes in electricity add to barriers to entry and/or expansion?

The working paper lists the seven electricity codes (plus the Smart Energy Code) that are currently in force. This volume of documentation does present a level of detail that may be intimidating to potential new entrants to the industry. However it also reflects the inherently complex industry and number of commercial and contractual interfaces that the codes seek to describe.

Amalgamating the codes is unlikely to significantly reduce the volume of terms and information required to define the industry arrangements but would just re-locate these discrete packages into a single unified document. However, as each type of industry licence holder is currently party to specific codes, as opposed to the full suite, they can avoid much material which may not be relevant to them whereas unifying the codes would undo this. This may further increase the challenges for smaller parties and new entrants to understand and engage with code changes relative to larger established parties who can afford more resources to understand and manage the document. Although not ultimately a barrier to achieving amalgamation, consideration should be taken of the substantial work required to unify the current purposes and varying styles that have evolved in the present individual codes. Industry parties (prospective and new entrants or otherwise) are best able to advise on the relative merits of amalgamation options.

The associated CMA working paper makes reference to potential duplication of information between the codes (e.g. Distribution Code with the Grid Code and DCUSA). In our role as code administrator we support ongoing housekeeping modifications to remove any unnecessary duplication, incompatible definitions and any redundant terms that are legacy remnants, in order to maintain the codes in as lean a form as possible.

The working paper refers to work by Cornwall Energy for DECC which identifies the various credit requirements and security arrangements under the different GB codes. Consideration of potential revisions to the credit requirements should take into account the different risks that arise under the activities covered by the various codes. However, if these differences in credit requirements and security arrangements are shown not to be efficient or in consumers' best interests (noting the purpose of the credit requirements is to protect consumers) then a single review may be an effective approach to achieving consistent arrangements.

Does the current system of industry code governance act as a barrier to pro-competitive innovation and change?

In terms of code governance, whilst the various codes have followed their own development paths there has been a general convergence towards standard open governance arrangements. As noted in the working paper, to an extent this is now assured by the Code Administration Code of Practice (CACoP) which stipulates a standard of governance that code administrators should observe.

A single governance arrangement covering the scope of all the existing codes may help reduce timing issues that arise from interactions between the current separate code development panels. However, a panel spanning all the current codes would need to consider a very large range of interactive topics. Industry parties will be best able to advise on the most appropriate trade-off between more panels or wider scopes.

We recognise the resource demands that are made of all companies that participate in governance arrangements, which will comprise a larger proportion of resource for smaller parties. Under CACoP Code Administrators are required to support all parties who seek to engage and progress change, and in addition to the supporting materials and 'tutorials' we and ELEXON make available on some of the more complex areas (e.g. charging), we have proposed changes on behalf of smaller parties (as have consultancies).

Finally, it should be noted that the new European Network Codes are in the process of being implemented in GB. The cross code impact of these European Network Codes already requires consideration of the interaction of both content and governance arrangements in order to implement these changes and whilst change will be managed generally through each specific code governance, additional measures to ensure coordination have been put in place[3]. Given these developments, any new code governance arrangements for electricity or gas must be mindful of the new EU code requirements and the ongoing work and resource to implement these.

NG/LAD 27 March 2015

[3] Special arrangements have been made to prevent existing governance arrangements from having jurisdiction over or being used to block the European codes.