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Dear Sirs

Energy Market Investigation: Possible Remedies

Thank you for the opportunity to respond to your provisional findings and possible remedies.

This response is provided on behalf of National Grid Electricity Transmission plc (NGET) and National Grid Gas plc (NGG). NGET owns the electricity transmission system in England and Wales and is the National Electricity Transmission System Operator (NETSO). NGG owns and operates the Gas Transmission System and owns and operates four of the gas Distribution Networks.

We have summarised our views in Appendix 1, attached to this document. Our response does not contain confidential information and we are happy for it to be published.

Yours faithfully

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Appendix 1 – Response to Provisional Findings and Possible Remedies

We offer our thoughts on the CMA's provisional findings and possible remedies published on 7th July 2015 below.

We will address the following areas where adverse effects on competition (AECs) have been identified:

1. Locational prices for transmission losses
2. Contracts for Difference
3. Gas and electricity settlement
4. Industry codes

1. **Absence of locational prices for transmission losses and constraints**

In this section, we begin by outlining our understanding of some of the reasoning that has contributed to the current arrangements and by indicating some of the considerations that might be useful to take into account in a move to variable pricing of losses. We go on to address the questions set out in paragraph 20 of the Notice of Possible Remedies that specifically relate to Remedy 1.

Determining an Appropriate Signal (Ex ante vs. Ex post)

In accordance with our duty to develop and maintain an efficient, coordinated and economic transmission system and to facilitate competition, National Grid has supported and participated in the assessment of market rule modifications that have sought to improve transmission pricing beyond those longer term investment related signals present in TNUoS charges.

An accurate mechanism for reflecting transmission losses through zonal pricing should in theory provide gains in efficiency by improving cost reflectivity and hence improve competition by removing a cross-subsidy. However to date, assessments of proposals to introduce short-run locational signals have not been able to sufficiently demonstrate how their potential benefits might outweigh their potential risks. A key challenge is how to devise a mechanism that offers an appropriate balance between accuracy and certainty to allow those gains to be made.

Calculating zonal loss signals on an ex ante basis has the advantage of providing some predictability of a party's exposure, thereby permitting them an opportunity to manage it (for example, if meter volume adjustments are known then suitable contracts can be entered to avoid any resulting imbalances). However this requires the forming and applying of assumptions about the anticipated operating conditions. The sensitivities of these assumptions are important in determining the level of economic accuracy that can be achieved. An averaging methodology over zone and season was prescribed under the rejected BSC modification P229, however given that this would not always accurately reflect the particular impact a participant has on actual variable transmission losses, sub-optimal outcomes can reasonably be expected. Since P229 was last contemplated, variability arising from the growth in intermittent generation has exacerbated this issue, further limiting the feasible level of accuracy that can be achieved ahead of real time.

Elsewhere, some systems attempt to address this trade-off between predictability and accuracy by calculating locational prices in real-time (making them available ex post), whilst offering products that give parties the option of hedging their exposure to those prices. However we are aware that such products emerge from market need and may add a further layer of administrative cost, effort and complexity to electricity market arrangements. This might present a risk of stifling competition if the associated complexity is such that potential new entrants are deterred from entering the market. In this context, weighed against the estimated benefits[1] of locational pricing for losses, it is important to take account of proportionality in the assessment of any proposed solutions.

Other Considerations

As noted in the provisional findings, the EU's Capacity Allocation and Congestion Management (CACM) regulation requires that regular reviews be undertaken concerning the efficiency of the bidding zone configurations. Any changes to introduce zonal pricing for losses would benefit from being done in such a way that is consistent with, and/or able to align to, any future market splitting that is undertaken to better signal constraints. Considering locational pricing for losses in isolation of any mechanism for constraints (or vice versa) could risk giving rise to conflicting and/or incompatible interactions that lead to inefficient signals.

Previous analyses of potential locational loss signals have also considered the interactions with the investment related signal present in TNUoS. Given the TNUoS methodology is also likely to require modification if revised bidding zones are introduced, the interactions between loss factors, constraint signals and TNUoS should be examined.

Earlier proposals to introduce transmission loss signals have sought to inform market parties of the implications of generating or consuming electricity in different geographical locations. The allocation of losses between generators and suppliers is determined by the voltage level at which each is metered. By this means, losses on a generator's step-up transformer are allocated to the generator. Settlement metering at the low voltage side of supergrid point transformers ensure distribution losses are allocated to distribution users and allocates the supergrid transformer losses to the transmission system loss total. We understand the 55% share of the total variable transmission losses, allocated to suppliers, was intended to promote symmetry in the treatment of generator and supergrid point transformer losses between generators and suppliers respectively. For example, this symmetry might better provide appropriate signals to consumers and distribution connected generators.

We understand that producers and consumers connected to the distribution networks already include a location specific allocation of distribution losses. If a locational signal for transmission losses is applied in an equal and opposite manner to production and consumption BMUs then this should provide consistent signals to distribution connected

[1] Provisional Findings Report, para. 5.47 cites Net Present Value (NPV) benefits over 10 years between £160 million (Redpoint) and £275 million (LE/Ventyx)

generators, whether they choose to participate directly in the wholesale market (as a generator) or contract with a supplier to reduce its net consumption.

The approach of signalling the locational impact of losses by means of adjustments to users' metered volumes (as proposed in P229), would require the system operator to take account of the potential for a significant difference between contracted and delivered volumes when issuing balancing instructions in some locations[2]. With an increased variability in loss factors from those currently applied in the market, there would need to be a process change to manage this issue.

Remedy 1:

(a) What would be an appropriate method for ensuring that variable transmission losses are priced on the basis of location?

In theory, an efficient and accurate set of locational price signals can be derived from the simultaneous optimisation of losses and constraints in real-time. Coherent separation of the impact on variable losses from constraints can be achieved by performing a parallel optimisation with transmission capacity constraints relaxed. If in addition transmission users have opportunities to access appropriate location hedging products[3], then the expected values of the derived short-run price signals can be made sufficiently certain to inform users' long-run locational decisions and thereby might replace the need for the locational signals in TNUoS.

To move directly to such a model would require a significant step change from the present arrangements and may create considerable uncertainties for market parties. If an evolutionary approach is pursued which addresses the most material aspects first, then reference to the underlying objective should help inform the approach. Appendix 5.2 refers to achieving a more efficient allocation of resources the closer that prices get to reflecting the incremental costs of supply. If the objective is to improve short-run dispatch of generation and the response of demand, then the reforms should encourage market parties to anticipate and respond appropriately to actual real-time prices. In the context of intermittent generation reducing the predictability of the generation mix for given periods, such signals may not be feasible on an ex ante basis. Alternatively, undertaking an approach similar to P229, that seeks to develop approximate but stable ex ante signals, may have the effect of better informing long run locational decisions.

(b) How should the variable transmission losses be allocated between generators and suppliers?

(i) Is the 45-55 split appropriate or could efficiency be improved further by changing this allocation?

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[2] For example, with a single transmission loss factor, the SO will know that if they instruct a generator to deliver a given volume, the volume delivered by any given unit will be slightly higher according to that factor (which should net off against system losses at GB level). Under variable loss factors, the volume that can be expected to be delivered from a given instruction will vary (under or over the given instruction) dependent on that generator's location.

[3] The availability of such hedge products would need to reflect the present and future network capacity and loss performance as resulting from expected network investments.

We do not think the allocation of total transmission loss costs between generators and suppliers necessarily affects the scope for developing more efficient signals. For example, it would be possible for generator signals to identify the marginal impact on total losses caused by each generator while overall the revenue impacts of these signals sum to zero, consistent with notionally allocating the total cost of losses to suppliers. In this example we would expect the market energy price to adjust from present to reflect this 0:100 allocation. As there are likely to be winners and losers in any transition to a new allocation of losses we suggest a change away from the 45:55 split is best avoided unless other benefits can be demonstrated as being significant.

(c) What will be the distributional impacts of this remedy? Should the CMA take these into account in coming to a view on the proportionality of this remedy?

Any changes to arrangements for allocating costs will have distributional impacts. We agree with the direction of transfers described in paragraphs 5.48 and 5.49 (of the provisional findings report), broadly that is, transfers from consumers in the south and generators in the north to generators in the south and consumers in the north. The principal objective that the reform would be seeking to deliver should inform the extent to which these distributional impacts are taken into account in the assessment of the remedy. The responses from market participants that the remedy primarily seeks to motivate, that is, short-run behavioural changes or long-run locational decisions, should inform any assessment of proportionality. Those most exposed to the impacts should be those parties who are identified as being best able to respond to the signals, and in doing so, are delivering the improvements to efficiency that are sought after.

(d) Should the CMA implement this remedy directly, ie via an order, or should it make a recommendation to Ofgem to initiate a BSC modification instead? Are there any particular aspects of Ofgem's objectives and duties to which the CMA should have regard if implementing this remedy by a licence change?

A considerable amount of change has taken place in the electricity market since P229 and the locational pricing mods that preceded it were considered by the industry. Therefore, whatever process is used to progress the CMA's preferred solution, should allow sufficient opportunity for the industry to contribute to developing the details for implementation. The BSC modification route (with workgroup and consultation processes) provides a robust and transparent governance mechanism for doing this however may not guarantee a timely delivery of change.

2. <u>Contracts for Difference</u>

Concerning the AECs and remedies pertaining to the Contracts for Difference (CfDs), as the EMR Delivery Body responsible for administering the competitive CfD allocation, we see the value to potential applicants of a transparent process, enabling them to prepare effectively for the start of the CfD rounds. With regards to our activities in this area, we welcome any suggestions on how the transparency of the delivery function might be improved.

3. <u>Gas and Electricity Settlement</u>

We agree with the CMA's view that accurate and timely settlement is a key feature of well-functioning energy markets. Accurate settlement systems are crucial to enabling the provision of clear signals to market participants in order to incentivise improvements in efficient system operation.

Project Nexus

We agree that delivery of Project Nexus has a key part to play in gas settlement, improving the allocation of gas across distribution networks and facilitating the early implementation of smart meter technologies. Alongside ensuring that the industry transitions to a stable and reliable platform with the required capabilities, its timely delivery is an important priority. To that end National Grid had raised a UNC Modification 548 to set implementation of Project Nexus for 1st October 2016 together with interim delivery milestones to ensure the revised programme remains on track. Given that networks were prepared to meet the original date, and their commitment to the revised one, as exemplified by raising the modification proposal, there would appear to be little benefit in additional regulatory intervention.

Electricity Settlement

In combination, smart meters and Time of Use Tariffs have significant potential to facilitate the smoothing of within-day demands. Whilst we are not in a position to comment on the detailed system or metering/supplier requirements necessary to implement domestic half-hourly settlement, we are very conscious of the potential benefits it could bring to operating the system and support efforts that aim to bring it into effect as early as it practically can be.

Ensuring that parties have suitable data systems in place, that are equipped to manage very large volumes of consumption data, is likely to present a challenge to introducing a cost-effective solution for half-hourly settlement of customers in profile classes 1-4. In addition to this, realising the benefits associated with half-hourly settlement depends on customers being sufficiently engaged with the process and well-informed about how to make the most of new tariff options they have available. It is important for customers to understand that moving onto a time of use tariff may not necessarily lead to a reduction of energy used or, depending on their respective consumption patterns, of their energy bills. This requires a co-ordinated approach across industry parties putting appropriate commercial frameworks in place to safeguard the consumer experience of the transition between settlement arrangements.

4. Industry Codes

When assessing potential AECs related to the industry codes, there is value in considering the extent to which the current framework promotes the delivery of changes that will be of specific benefit to the consumer and how this can be improved. However, this issue may be a wider matter than just the industry code governance arrangements and so we are not confident that some of the remedies suggested here would resolve the issue.

Particularly relevant to this consideration is the level of complexity and detail inherent in the arrangements laid out in the GB codes. As several respondents to the Updated Issues Statement have already pointed out, their complexity is at least partly a reflection of the industry they seek to describe. The language used is precise and is written in a way that seeks to avoid ambiguity in interpretation and enforcement, thereby circumventing the time and costs associated with resolving issues and disputes. To their own various levels of maturity (dependent on their respective histories), the codes can be seen as the amassed output of industry and legal expertise. The advantage of this rules-based approach (as opposed to principles-based) is that participants and stakeholders benefit from a level of assurance in terms of regulatory and contractual certainty and clarity.

However, the corollary to this is that any proposed changes are likely to require engagement from industry parties with sufficient experience and knowledge of the contract structure (such as by participation in developmental workgroups). In the case of wider more comprehensive changes (such as SCRs) this demand for expertise can be considerable. Since this time and knowledge is a finite resource, choices must be made by organisations (to which those representatives belong) as to how their attention can be best allocated between priorities. Consideration also needs to be given to the IT system changes that are frequently required as a consequence of larger scale policy reforms and the impact this has on constraining the ability of parties to actively promote changes.

Therefore, the introduction of changes that aim to help industry parties make optimal use of time and resources, should facilitate more timely delivery of changes that are of particular importance to Ofgem and DECC. One means of achieving this might be to supplement the existing strategic plans from Ofgem and DECC with details concerning anticipated potential code changes. Being able to see the trajectory of regulatory focus in advance would help industry parties ensure they have appropriate staff levels concentrating on these areas that complement the regulatory agenda. Enhancing clarity at the early stages of the change processes should support more effective participation in the latter stages.

There may be opportunities to refine modification processes, particularly those associated with more substantial changes like SCRs or the introduction of European Network Codes (ENCs), provided that sufficient opportunity is offered to industry to engage on both policy development and any subsequent implementation and review. These types of changes require appropriate engagement with and from industry on both the policy matters (currently the Ofgem-led phase in SCRs or the drafting phase of European Network Code) and the detailed code implementation. Regarding the development of EU policy, National Grid aims to inform GB parties of discussions that are taking place and outline our views on particular issues, we are not in a position to represent those parties but rather we seek to encourage the industry to participate in the relevant consultation processes to ensure their interests are fully represented. Both the formulation of policies and the determination of implementation details are fundamental to developing industry frameworks in a way that does not cause unintended consequences and we would be cautious of changes that risk curtailing opportunities for industry input by imposing rigid timeframes. However, experience has demonstrated that there can be duplication of debate taking place on the same issues in the different fora. For example, in the process of agreeing the ENCs, issues have been discussed and agreed within EU groups that are later replicated within GB code discussions; similarly, analysis and debate that had been carried out in the 'policy phase' of the Electricity Balancing SCR was repeated in the formal modification process. There may be potential to streamline these end-to-end processes by defining the scope of assessment to restrict issues that are deemed to have been resolved or understood in the first phase being re-opened in the second (potentially causing delays to delivery).

Whilst there is opportunity for consumer representation on Code Panels, in our experience they are not (or rarely) directly represented at the development workgroup levels of code modifications. There can therefore be an absence of an explicit consumer advocate at the industry-led stage of the change process. The Code Administrator Code of Practice (CACoP) Principle 1 states that ‘Code Administrators shall be Critical Friends’, which includes supporting smaller parties and consumer representatives through code modification processes and encouraging appropriate representation in them. Provided that the representatives are equipped with a suitable level of industry understanding, consumer representation at the working level of change processes could improve the balance of focus in assessing changes. This would, of course, require such consumer representative bodies to be in a position to commit resource to the change process.

Below we address the proposed remedies (within Remedy 18) in turn. A fundamental factor underpinning our consideration of these, and this AEC, is that on the basis of the codes’ complexity any change will generate a degree of compromise between time and quality and we would be keen to ensure that timeframes are not rigid to the detriment of necessary assessments of changes.

Remedy 18a – Recommendation to DECC to make code administration and/or implementation of code changes a licensable activity

We understand that the administration activities of some codes are not attributable to any industry licence conditions. Those codes to which National Grid is party (the UNC, STC, CUSC, Grid Code and BSC) do have associated conditions contained in our Transmission Licences, each of those stipulates a requirement that the respective administrative function should be carried out having regard to, and consistency with, the principles outlined in the Code Administrators Code of Practice (CACoP).

In our experience and the case studies described in Appendix 11.2 the administrative function of the industry codes does not seem to have been the cause of delay or obstruction to the progress of modifications. These functions facilitate discussion according to their given governance processes, which are consistent with the CACoP. The key determinant of the pace of change is the extent and nature of engagement from industry parties and stakeholders involved in developing and quantifying that change, that is, the workgroup and, to varying degrees, the Code Panels. It is difficult to see how this pace could be accelerated by changing the status and/or remit of the administrator. Any new performance objectives that are placed upon delivery bodies should be on measures that are within their control. Without significant change to the governance procedures that they follow, and the level of authority conferred on the administrator to enforce the pace and quality of the development process, the scope for code administrators to identify and implement efficiencies within change processes is likely to be limited.

Remedy 18b - Granting Ofgem more powers to project manage and/or control timetable of the process of developing and/or implementing code changes

We note that under UNC governance rules Ofgem already has the powers, under specific circumstances, to raise modifications and direct timetables but these powers are not mirrored for other industry codes. There may be conditions where the provision of specific directions and deadlines regarding timescales will help encourage effective industry engagement at appropriate points in the change process. In particular, where the introduction of policies has the potential to impact upon multiple codes (such as SCRs or enacting the European Network Codes), Ofgem's ability and readiness to actively manage the sequence of assessment stages could be a valuable means of promoting efficiency of the change processes. For example, where it is anticipated that there may be interactions or consequential code changes, Ofgem's ability to stipulate time windows within which such considerations should be identified and contemplated, may help to maintain momentum through complex change.

More widely, we would be cautious of mandating unyielding and uninformed timeframes on modification processes as this may risk undermining the quality of the assessment required to ensure effective implementation. Still there may be opportunities to apply limits to the industry-led phase. Such limits could include the scoping of the inquiry of the modification assessment (for example, precluding issues that have already been consulted on from repeated assessment). We would recommend that if powers are granted to apply explicit timescales to change delivery that it can be demonstrated that those timescales were informed by engagement with industry, the timescales are reasonable, and an opportunity to appeal (for extension) is afforded to participants on specific grounds.

There is a level of due process that should be observed when industry changes are introduced which needs to be demonstrably robust, otherwise the conclusions could be vulnerable to challenge and possible reversal (for example, by Judicial Review) which will take more time and effort. In order for any extensions to Ofgem's powers to yield effective improvements, Ofgem needs to be sufficiently confident in applying those powers. As the CMA notes, Ofgem already has the opportunity within limited circumstances to apply direct changes to the UNC but it has not appeared to have had a particular appetite to do so.

Remedy 18c - Appointment of an independent code adjudicator to determine which code changes should be adopted in the case of dispute

In our view, an additional body is likely to lead to add an additional layer of uncertainty and administration into the change process, potentially detrimentally impacting efficiency.

We agree that the adjudicating body on code matters should have expertise and independence as prerequisites, and we believe that Ofgem fulfils this role. Having a single regulator with full oversight of the energy markets enables complex issues, which may exhibit themselves in different areas of the industry, to be approached in a holistic way. This can be especially important in light of the cross-references and interactions that can exist between the terms of the codes and various licence conditions. We do not see an obvious advantage of appointing a separate adjudicator and would be concerned that doing so might risk undermining industry's confidence, and expectations of seeing Ofgem's policy decisions coming into effect.

NG/LAD August 2015