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Dear Lewis

This letter provides our response to Ofgem's 'Electricity System Operator Incentives: consultation on a scheme for 2013' consultation. We welcome this latest set of proposals from Ofgem to which our detailed responses to the individual consultation questions are provided in the Appendix to this letter.

Summary
We remain strongly of the view that an appropriately balanced SO Incentive framework provides the best framework to ensure SO Balancing Costs are efficiently minimised by National Grid on behalf of our customers and end consumers:

- We agree that a further two year BSIS scheme provides an already understood and pre-defined incentive framework within which National Grid is able to optimise balancing costs on behalf of consumers.
- A two year scheme will also ensure that incentives remain focussed in the short term and serve to build further stakeholder confidence in the enhanced modelled approach to determining an incentive cost target.

Whilst we support the overall approach of an incentivised framework, we remain concerned that a number of the parameters do not reflect experience gained from the 2011-13 BSIS scheme and need to be examined further prior to any final proposed scheme parameters. We are happy to provide any further information to help support this process. In particular:

- The constraint model discount factor was introduced to incentivise the appropriate use of contracts and trades ahead of the Balancing Mechanism (BM) where it is economic to do so. As such, the discount factor should only apply to the proportion of constraint volume deemed appropriate to resolve ahead of real time rather than applied to the total modelled constraint cost as proposed. Alternatively, if the discount factor is applied to total constraint costs then it should take into account an average achievable discount;
- The outage plan used to set network capability in the incentive model should be based on a timescale that reflects the period of time within which the plan becomes more stable. At present the appropriate timescale for the outage plan is approximately 6 weeks ahead, not the year ahead position proposed in the consultation. The significant plan change seen as Transmission Owners implement RIIO arrangements makes this particularly challenging for 2013/14;
- Network faults should be able to be included in the outage plan. At present there is no allowance for the costs of network faults within the scheme. Network faults are a normal aspect of system operation and as such it is

reasonable that such costs should be covered by the scheme. Under the current proposals these costs could only be managed through an Income Adjusting Event; and

- The Income Adjusting Event (IAE) licence provisions should be retained but criteria should be clarified to address any stakeholder concerns. The IAE facility is in effect a Force Majeure clause, normal in most contracts, and designed to recognise that a contractual framework cannot cover all possible events. Any IAE notice submission is subject to Authority approval and a transparent industry consultation process.

Finally, we support the outline proposals for a discretionary reward scheme to sit alongside BSIS. With significant longer term drivers for change in the industry, the option to fund long term innovation that could mitigate future cost increases will serve the interests of consumers and help drive longer term innovation by the SO. Such a framework will require careful detailed design but could be developed in line with similar arrangements already established under RIIO.

Further detail on the above points

Constraint Model Discount Factor
Whilst it might be appropriate to apply a discount factor to the output of the constraint model given the way in which the model produces a constraint cost forecast[1], the proposed level of discount and the way in which it is to be applied is not appropriate. Currently a 41% discount is applied to the total output of the model (excluding headroom costs) in recognition of established means to managing constraint costs such as contracting and trading. This assumes however that we are able to achieve this level of discount against the BM price for all system constraint volume. This level of contracting and discount is not achievable in practice, particularly as the management of some constraints within the BM in real time may actually be the most appropriate and economic action that the SO can and should take.

Instead, if a discount is to be applied, it should be applied to a percentage of the total constraint cost to reflect an appropriate level of contracting or trading that can be achieved by us in managing constraints ahead of real time. Alternatively, if it continues to apply to the total volumes, the discount factor should be reduced to reflect that managing some constraints in the BM can be the appropriate and economic course of action to take. We can provide further analysis to support the calculation of an appropriate discount figure for discussion.

Outage Plan
We appreciate that setting the outage plan input for the purposes of modelling a constraint cost target is a balance between the strength of incentive on us to optimise the outage plan and the accuracy of the incentive target that the plan is used to create. We also acknowledge that in its consultation Ofgem has proposed to reduce the timeframe in which the outage plan is input to the constraint model from two years ahead (as now) to one year ahead in an attempt to redress this balance.

However, Transmission network outages have considerable potential to impact upon the level of system constraint boundary capability, which is then used in the incentive target setting model. If it is not reflected accurately within the model, then the incentive framework will not accurately reflect conditions on the system, reducing the strength of the incentive and introducing the possibility for windfall gains and losses. At year ahead, the timescale proposed for fixing network capability, typically only

[1] The constraint model forecasts the cost to resolve system constraints in the balancing mechanism and therefore does not recognise that National Grid has established methods by which these costs can be managed e.g. through the use of commercial intertripping arrangements, trading and contracts.

around one third of outage volume is finalised. Two thirds of the actual number of outage days are finalised within year.

We therefore consider that the outage plan should be input to the constraint model at 6 weeks ahead which will allow for a much more accurate reflection of Transmission System capability in timescales in which the SO can take actions to manage constraints. Such actions include contracting, trading and requesting enhanced services from the TO's to create additional boundary capacity. We also note that whilst the Network Access Policy (NAP) has been developed as part of RIIO to clarify SO-TO interaction processes, these processes are still in their infancy and are unlikely to become fully embedded in the short term.

Network Faults
We consider that there should be separate provision introduced for Transmission System fault outages within the outage plan, such that the costs of managing these are incorporated within the incentive. This is currently not the case under the existing scheme. Inclusion of network faults would allow timely and accurate reflection of such events within BSUoS charges and the avoidance of potentially late and uncertain BSUoS costs appearing through an IAE submission (see below).

Income Adjusting Event (IAE)
The consultation questions whether the introduction of mid-scheme update provisions[2] coupled with a 'two by one' year scheme structure would qualify the removal of the Income Adjusting Event provisions from the licence. The IAE provisions are critical for the management of liabilities that can arise from significant unforeseen circumstances (e.g. force majeure). The IAE is a mechanism that both customers and National Grid can employ to ensure the appropriate treatment of costs and revenues following such circumstances. Unforeseen events of this nature could still occur even with introduced provisions to allow for scheme methodology changes. It is therefore necessary to retain the IAE mechanism as a 'catch-all' for the protection of market participants, consumers and National Grid. Any concern can be addressed by the final sanction that the Authority has on the approval of any IAE costs.

In conjunction with changes to scheme parameters that help manage unforeseen costs the IAE threshold could be raised, for example, from £2m to £10m to reduce the possibility of such an event being triggered. In particular, this could represent a reasonable position if combined with a 6 week ahead outage plan and provisions for network faults within the modelling methodology as set out above.

Our views on the incentives that Ofgem proposes in addition to BSIS can be found in Appendix 1 to this letter along with specific responses to all of Ofgem's consultation questions.

We look forward to discussing the more detailed elements of modelling methodology and scheme(s) design with Ofgem over the coming months.

Yours sincerely,

[by e-mail]

Duncan Burt
Head of Commercial Operation, Market Operation

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[2] These will allow National Grid to apply for methodology amendments, update key inputs and make corrections to model/input errors at the mid scheme point.

Appendix 1: Responses to specific consultation questions

Chapter One

Question 1: Do you agree with our proposal to put a balancing services incentive scheme in place for 2013-15?
Question 2: How much confidence do you have in the ability of the models to set a robust target given recent developments to the models and methodology?

We agree that the proposed implementation of a Balancing Services Incentive Scheme (BSIS) for 2013-15 presents the most effective approach to delivering value to consumers over the proposed incentivised period. BSIS provides a pre-defined incentive framework within which National Grid can optimise balancing costs and against which customers can understand and to some extent anticipate the actions that we take to balance the network. This is as opposed to Ofgem's alternative cost disallowance proposal last year which presented significant risk to National Grid and consumers due to the uncertainty surrounding its design.

We understand that Ofgem had concerns last year on the ability of the models to set a robust and accurate target for incentive schemes from 2013, and that Ofgem's role is to protect consumers in this regard.

Over the previous few months we have thus sought to impart the confidence that we have in the work we are doing to enhance the current 2011-13 BSIS target setting models to both Ofgem and stakeholders. To this end we have held a number of industry workshops and shared more detailed model development findings with Ofgem. Since the changes we proposed and Ofgem subsequently accepted in July 2012 on the current 2011-13 scheme methodology, we have identified a small number of further changes to the modelling methodology to apply to a new scheme. This small number of further amendments shows the confidence we have in the now refined methodology to produce a robust and accurate incentive target in future.

Through our model development work, we are seeking to identify and ensure that the models continue to reflect system operation conditions that we experience in reality. As an example, we have recently set out at our Operational Forum an emerging frequency management system operation issue related to system inertia[3]. We will therefore work with Ofgem to develop the BSIS methodology to ensure that the costs associated with efficiently managing this issue can be incentivised appropriately.

A further two year scheme allows Ofgem and industry stakeholders to gain further confidence from the incentive cost target setting models (and the still relatively new modelled target approach) such that they may provide a robust platform for incentives from 2015 onwards as required.

Chapter Two:

Question 1: What are your views on making the balancing mechanism 'pseudo' prices an ex post input in the energy models? What additional considerations may exist?

We agree with Ofgem that Balancing Mechanism (BM) pseudo price should be an ex post input to the energy model to ensure that the possibility for windfall gain or loss is removed from this element of the model. It should also be stressed that the reassessment of this input from ex ante to ex post does not weaken the incentive on

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[3] This was presented at the Operational Forum in February 2013 and more information can be found on our website at: http://www.nationalgrid.com/NR/rdonlyres/D4ED97CD-0A7F-4F06-A85D-7161AEEF3519/59105/Frequency_Management.pdf

National Grid to reduce the cost of resolving energy imbalance and therefore there is no adverse impact of doing so.

We have tested a number of alternative ways of forecasting the BM pseudo price on an ex ante basis and have shared these results with Ofgem. Whilst some of these tested models have improved the error in forecasting these prices, inaccuracies cannot be removed altogether. Thus the most effective way to increase the accuracy of the model and to reflect our inability to accurately forecast this price is to make the BM pseudo price an ex post model input. Given that this price also feeds the other sub-models within the energy model, making the BM pseudo price ex post also increases the accuracy of the energy model as a whole.

A target that is set using ex post inputs within the energy imbalance model defines the most cost efficient way to resolve energy imbalance via the BM and therefore represents the strongest incentive target. Thus the incentive on us is actually strengthened when using ex post BM pseudo price. This is because we are incentivised to seek lower cost opportunities to manage energy imbalance than the cheapest solution in the BM such as by trading or contracting ahead of time.

Question 2: What are your views on the appropriate length of time for input of transmission limits? What value do you place on having forecasts ahead of time which are as accurate as possible?

As we set out in our response letter above we consider that transmission limits should be input to the constraint model at 6 weeks ahead of real time as this ensures that the outage plan is accurately reflected within the model. Not only does this approach reduce the possibility of windfall gain or loss resulting from changes that occur to the plan between year ahead and real time, but it also maintains the incentive on the SO to reduce constraint costs.

We recognise that the timing of this particular input to the constraint model is a balance; a balance between reflecting the outage plan as required to be managed by the SO in reality and maintaining an incentive on the SO to manage and optimise the outage plan. However, for the previous two years only one third of the total outage volume in terms of number of outage days has been finalised at the year ahead stage. This demonstrates the potential for significant error to manifest in the constraint model target which in turn has the effect of weakening the incentive on National Grid.

In addition, we note that upon implementation of the RIIO regulatory framework, there is potential for significant change to occur in the outage plan, which makes the derivation of a robust year ahead plan for the purposes of setting an incentive target challenging, particularly for 2013/14. Whilst the Network Access Policy (NAP) has been introduced as part of these arrangements to facilitate SO-TO interaction in this regard, the NAP process is unlikely to become fully embedded and therefore fully effective in the short term.

We therefore consider that the 6 week ahead timescale achieves the right balance for the next two year incentive scheme. It means that the significant work we have undertaken to enhance the constraint model over the past two years to increase the number of modelled constraint boundaries can used to maximum effect. If we were to employ a year ahead outage plan within the enhanced constraint model, there would be significant risk associated with attempting to forecast every boundary limit capability for all the possible constraint combinations that can occur on the system that far ahead of real time.

In addition, from the 6 week ahead timescale, National Grid continues to be incentivised to, for example, enter into constraint contracts or request enhanced services from the TOs (e.g. enhanced ratings) in order to reduce forecast constraint costs.

Question 3: What are your views on the requirement for, and appropriate level of, a discount factor to be applied to the constraints model?

As set out in our response letter above, we do not agree with the proposed level or application of the constraint model discount factor. Whilst it might be appropriate to apply a discount to the output of the constraint model to reflect the various established methods with which we can manage constraint costs, it is unreasonable to assume that we can achieve a 41% discount against BM price for all system constraints. In fact, in some instances, leaving the management of a constraint to the BM will be the most cost efficient option to the SO and therefore end consumers. In these cases, the SO should not be automatically penalised through the scheme design for making the most cost effective and economic decision.

Instead the discount factor should represent a reasonable level of actions that can be achieved by the SO to manage constraint costs ahead of real time including trading, contracting and commercial intertrips.

Chapter Three:

Question 1: Do you agree with our proposals for the key parameters of a BSIS?

We agree with Ofgem's proposed scheme parameters (in terms of cap/collar and sharing factor) and consider that a 'two by one year' scheme structure would appear reasonable alongside a mid-scheme review point.

We appreciate that there is likely to be significant change within the industry in the medium term with developments such as EMR likely to impact upon the role that the SO undertakes. Therefore the proposal for a two year BSIS scheme provides a suitable balance between providing the appropriate strength of incentive on the SO to manage down costs in the short term and ensuring that incentives remain current and relevant in the medium to longer term. We also consider that a further two year scheme will allow further confidence to be built in the now enhanced modelled approach to BSIS.

Question 2: What are your views on the one year update provisions and the requirement for income adjusting event provisions?
Question 3: Do you have any views on the types of inputs that may be suitable for adjustment as part of the mid-scheme provisions?

The one year update provisions are critical to keeping the scheme target on track and maintaining the strength of incentive on National Grid. Ofgem's proposed mechanism provides a transparent and predictable method with which to achieve accuracy of the incentive target and minimise windfall gain or loss to us and consumers. We will work with Ofgem over the coming weeks to identify and define those inputs that may require updating within the models at the mid-scheme stage which will ultimately be defined within the modelling methodology statements.

However, we do not consider that the proposed introduction of a mid-scheme update mechanism provides sufficient rationale for removing the Income Adjusting Event (IAE) provisions. Regardless of methodology design, there will still be potential for force majeure-type circumstances which the IAE provision is designed to manage. As we set out in our response letter above, this provision provides an appropriate 'catch-all' which can be triggered by industry parties as well as National Grid and ensures that costs/revenues can be managed appropriately following such an event.

Given that the Authority ultimately determines as to whether an IAE has occurred and that the threshold at which an IAE can be triggered could be raised (we have suggested to £10m), we consider that these provisions should remain in force for the protection of consumers.

Question 4: What do you consider to be the merits/disadvantages of applying the scheme retrospectively to the 1 April 2013? Do you consider this to be the best option for the 'interim period'?

Retrospective application of the scheme to 1st April 2013 ensures that the strength of incentive on us is maintained following the expiry of the current 2011-13 scheme on 31st March 2013. We thus continue to be incentivised to seek the most cost efficient and economic actions to operate the system even prior to the final 2013-15 scheme design being agreed. Retrospective application of a scheme would therefore be in the best interest of consumers.

In terms of a customer charging impact, it should be noted that the only element that would be applied retrospectively upon implementation is the profit/loss element for the scheme from 1st April. This is typically a very small percentage of the total BSUoS charge even at the proposed scheme cap/collar levels (circa 2%).

Chapter Four

Question 1: What are your views on the additional incentives that we are proposing to include alongside a BSIS?
Question 2: In particular, what are your views on the merits of including a discretionary reward scheme alongside a BSIS? And what are your views on our proposals for the parameters of a scheme?

<u>Wind Generation Forecasting Incentive</u>
In principle we support the introduction of a renewable generation forecasting incentive, alongside BSIS, which seeks to drive improvement in our forecasting accuracy and provide valuable information to the market. However, we note that Ofgem has maintained its proposed cap position for the incentive at 0% forecasting error and that the rationale for this is to maintain the incentive on us to continually improve.

There is a natural limit as to how accurately wind power can be forecast given accuracies of weather forecasting data of around 3.5% error and thus 0% wind generation forecast error over any period of time is not possible. In addition, as performance approaches this point, the effort and cost required in improving performance grows exponentially. Given that 0% error is unachievable, this incentive as currently proposed is inappropriate and does not adequately incentivise the improvement in accuracy that Ofgem is seeking. The targets that Ofgem propose for the two year incentive are based on our forecasting performance for the previous two years which has required significant investment to achieve. We also note that due to the Connect and Manage regime, and the connection of more offshore wind generation, forecasting is likely to be more challenging over the next two year period.

We therefore propose that either the maximum reward that can be obtained from the incentive be increased to reflect the level of cost investment and resource required to make even incremental improvement in this area or the cap be moved to a level of 3.5% forecast error. We consider that the cap profit level should be increased to £500k per month which would also take into account increased external reporting requirements requiring additional National Grid resource. Whilst this appears to make the incentive design asymmetric, it in fact seeks to counterbalance the additional effort required to achieve improvement in average forecasting error. Thus the strength of incentive on us to invest in forecasting improvements and ensure that wind information is provided in timely manner to the market is maintained despite future challenges of doing so as set out above.

Black Start Incentive

In its consultation, and given the proposed 2 year BSIS incentive, Ofgem consider the merits of using the current approach to setting a Black Start cost incentive which requires us to undertake a forecast of Black Start costs for the two year period. However, as the costs of Black Start become more volatile they also become less predictable which has the potential to undermine this target setting approach. We therefore consider that there continues to be merit in our longer term incentive proposal that we put forward in our SO Incentives plan submitted to Ofgem in May 2012[4]. In our plan we proposed a new 8 year approach to Black Start incentivisation where an incentive cost target is determined through a market-based approach rather than the current station by station cost approach.

A longer term incentive framework, where revenues are de-coupled from specific purchasing decisions, provides stronger incentives on us to strike the appropriate balance between retaining legacy contracts and / or entering into contracts with new service providers. It also provides us with incentives to innovate, including for example to support alternative sources of BS service which may prove to provide better value for money to consumers in the longer term, and to trade off the various costs associated with the provision of BS services, for example the costs of black start warming which have become increasingly material over recent years.

In the event that a shorter term incentive is sought to align with BSIS, there should be a review of the extent to which the SO can control and/or forecast particular cost elements for Black Start in the short term as we have already done with BSIS. We consider that there is scope for some cost areas, such as warming costs incurred to maintain Black Start service capability in low availability zones, to be treated on an ex post basis to avoid windfall from an inaccurate target.

Whilst Ofgem notes that licence provisions designed to allow funding for the procurement of new service providers currently exist, the mechanism for recovering such costs is not clear. Under a shorter term Black Start incentive arrangement, it is critical that we have clarity on this process such that we can continue to procure new services as required and recover the costs of doing so. Again this is something that our longer term incentive proposal sought to address.

Discretionary Reward Scheme

We consider that there is merit in a discretionary reward scheme to complement BSIS and encourage longer term innovation and framework change. Such a scheme will ensure that the SO is incentivised and rewarded for innovation that is not necessarily rewarded through the design of a BSIS scheme. Given the timescales associated with undertaking innovation projects, we consider that the discretionary reward scheme should be in effect for the whole RIIO-T1 period rather than just for the proposed 2013-15 BSIS period.

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[4] Our plan submission can be found on our website at: http://www.nationalgrid.com/NR/rdonlyres/13531149-75DC-4BF9-BD27-2A0C9425A649/54364/ElectricitySystemOperatorExternalIncentivePlan.pdf

We look forward to discussing the design of the reward scheme with Ofgem further in terms of how we may apply for and receive a reward under such a scheme and how this potentially interacts with the other innovation funds developed as part of RIIO.

Question 3: What are your views on the additional incentives that we are proposing not to include alongside a BSIS?
Question 4: Do you agree with our proposal not to include a BSUoS forecasting incentive? What measures could help to reduce volatility of BSUoS charging going forwards?

<u>Transmission Losses Incentive</u>
Given the extent of our ability to both control and forecast transmission losses, Ofgem's proposal to remove the financial incentive on us to reduce their volume would appear reasonable. Our TO business will continue to invest in equipment to minimise losses, consistent with our RIIO-T1 proposals. As the NETSO we are however best placed to report volumes and drivers of losses on an ongoing basis and agree that a reputational incentive in this area may be appropriate.

<u>BSUoS Forecasting Incentive</u>
We consider that to have a BSUoS forecasting incentive alongside a BSIS scheme would introduce perversities and therefore agree that such an incentive should not be included. We also note that we have a new Code obligation to publish more frequent BSUoS forecasting information to the market.

Following the RIIO stakeholder engagement sessions that we held last year, and more recent engagement on SO Incentives, we understand that our stakeholders value stability and predictability of network charges including BSUoS charges. We will therefore continue to work with stakeholders through the Transmission Charging Methodologies Forum (TCMF) to understand the priority of this work and develop a way forward as required.