National Grid Electricity Transmission

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Dear David

Electricity System Operator Incentives from April 2017

We welcome the opportunity to respond to the above consultation published on 4th August 2016. This response is made on behalf of National Grid Electricity Transmission plc (NGET) and we have addressed our response to the specific questions posed by Ofgem in the consultation.

We support the view that there is a need to conduct a fundamental review of SO incentives. Since the current scheme was introduced there have been significant changes to the electricity system and the actions that must be taken to ensure secure operation.

With the significant increase of solar and wind generation, the location and output of generation is now more weather dependent. The pattern of flows on the system and the location of constraints are therefore less predictable than in the past. As much of this intermittent generation is connected to distribution networks, forecasting the demand at a transmission level has become increasingly challenging. The growth of renewables has also impacted the inertia of the system. When the volume of renewables is high, the inertia of the system is reduced and a higher volume of frequency response is needed to manage the system within limits. Managing the voltage on the system has also become more challenging as the characteristics of demand and the network have changed. As a result, an increasing proportion of actions are now taken to manage system issues rather than for energy reasons.

The changes described have a number of implications which need to be considered when developing an incentive scheme.

Firstly, given the high variability in generation and demand, the concept of a typical day on the system is becoming less relevant. As a result, the role of the SO has evolved and requires increasing levels of risk management compared to the past. When taking decisions on actions in advance of real time, the full range of potential outcomes together with their likelihoods must be considered in order to manage the risk. It is highly unlikely that the decision, which is optimal given the uncertainty, will be the same as one taken if all the system conditions are known in advance. An incentive scheme based on a 'mark to model' approach is therefore more difficult to implement as the level of uncertainty increases.

Secondly, as a larger proportion of actions are taken for system reasons, the 'physics' of the system is becoming increasingly important and so decisions may appear uneconomic if this is ignored. Any incentive scheme must take into account both the physics and economics of the system.

Finally, as the optimisation becomes more complex it is increasingly likely that a single action may be taken to solve more than one issue on the system and so it becomes more difficult to operate a disaggregated incentive scheme.

The above narrative focuses on the role of balancing the system. However, the SO also facilitates high levels of access to the system to enable network maintenance and reinforcement which delivers consumer benefit in terms of an improved network. Financial incentives have focused the SO to innovate with balancing services to help achieve all of this and continue to deliver substantial savings to the end consumer.

Given all these challenges of current and future system operation, we therefore support the view that there is a need for a fundamental review of the incentive scheme and we look forward to working with Ofgem on moving towards more principles based incentivisation which more appropriately encompasses the performance of the SO as a whole, taking into account the SO's role in risk management.

However, we recognise that this fundamental review cannot be achieved by April 2017 and so we believe that continued financial incentives within the current framework are an appropriate means of providing a suitable risk/reward mechanism to the SO, to reflect its role in delivering cost savings for the consumer, in the intervening period. We also agree that maintaining the existing incentive framework, from April 2017, will enable both Ofgem and the SO to focus resource on the fundamental review whilst providing confidence to the market that the SO will remain focussed on performance. We think that an interim incentive scheme with no definite end date will cause uncertainty for the market, significantly complicate the Licence terms and could be avoided by aligning the scheme with the financial year, setting the interim arrangements to end on 31st March 2019.

We recognise that there are potential improvements to be made to both the methodologies and the models which underpin the scheme from April 2017. We will work with Ofgem and seek to address the limitations of the regression models whilst recognising the restricted time available. We therefore welcome Ofgem's minded to position to maintain the existing incentive framework whilst seeking improvements which benefit consumers.

We note and support Ofgem's view to introduce new incentives for a short term demand forecast. We agree that there is value to the market for delivery of accurate short term transmission system demand forecasts. This would send clear signals to the market. However, we believe there are many variables which make creating an incentive similar to the wind generation forecast undesirable. We believe an incentive which focusses on how the SO engages with industry and delivers an appropriate forecast will reflect a more appropriate balance to any risk / reward framework.

We agree that greater transparency, particularly around procurement of balancing services, will be beneficial for the market as it will help sharpen investment signals and enable providers to deliver the right services at the right time. It is prudent to introduce a financial incentive on the SO to improve transparency and openness; which reflects both the value delivered to the consumer, and recognise the SO's available resources to deliver both the improvements and any subsequent requirements.

We agree that removal of the MDLC term will enable both Ofgem and NGET to focus resources on the fundamental review of incentives. We also agree that removal of the IRM would achieve the same aim; however we are keen to investigate if the funds made available under the current IRM could be utilised elsewhere to deliver, for example, further consumer benefit or enable more routes to market for new providers.

We welcome the proposal put forward by Ofgem for a mechanism which allows the SO to exchange funds with the TO in order to reduce total system costs. As noted in Ofgem's consultation, the actions taken by TOs directly impact on system operation costs and whilst coordination has been improved through the Network Access Policy, there are limitations to the current framework. These limitations extend to an increased spend for the TO which would significantly decrease costs to the SO, and therefore overall system costs. This proposal provides opportunity for the SO and TOs to increase coordination and deliver whole system cost savings to the consumer. We broadly support the proposed funding mechanism, however we believe that an approach which encompasses a fixed price provides greater certainty for the SO and ultimately the consumer. Additionally we see a clear need to keep this incentive separate to BSIS.

The remainder of this letter addresses the specific questions raised in the consultation document.

Chapter 2

Q1a. Should we place financial incentives on the SO in the period between 1 April 2017 and when we are in a position to implement longer term SO incentives?

We believe maintaining financial incentives on the SO, from April 2017, is an appropriate approach in the interim period whilst a fundamental review is conducted. As noted in the consultation document, the significant growth in embedded and intermittent generation, implementation of Electricity Market Reform (EMR) and integration with neighbouring electricity systems, have introduced major changes to the energy market. As a result the SO's role of managing the risks whilst balancing the system has expanded and become more complex; we therefore agree a fundamental review of how the SO is incentivised is fitting.

As noted in the consultation, the year on year increase in financial target reflects the increased complexity of managing the electricity system due to, for example, growth in intermittent and embedded generation, enabling Connect and Manage, loss of inertia and closure of thermal plant. Despite these challenges Ofgem have been able to monitor, and challenge, the benefit delivered by NGET through the modelled target approach and subsequently recognise the efforts taken to drive down balancing costs.

Whilst we agree that short term schemes provide less certainty for the SO regarding parameters of future schemes, and therefore potential 'loss' of longer term benefits, we believe a short term incentive will continue to drive the SO to identify and deliver benefits over a shorter timescale.

We agree that strong financial incentives are an effective way to drive efficient SO behaviour and should be used during this interim period.

Q1b. If we maintain financial incentives from April 2017 to spring/summer 2018, should we use the existing BSIS framework?

We believe the BSIS framework has driven the SO to deliver significant savings to the consumer, as noted in Ofgem's consultation, and that for the immediate future a modelled approach provides a fair reflection on the increasing complexity of the SO's role in balancing the electricity system. As mentioned in our response to Q1a, the modelled approach has aided the monitoring activity undertaken by Ofgem; challenging NGET's balancing activities and the efforts taken to reduce costs.

We believe the indeterminate end date of the incentive scheme, as put forward, will likely cause uncertainty and require significant re-writing of the Licence. We suggest the simpler approach provided by aligning the end of incentive with the financial year end 2018/19 would be beneficial by giving increased surety.

We note and agree that, given the BSIS framework has been in place since 2011, NGET, industry and Ofgem have significant experience with this approach, and that continuation of this approach should allow parties to focus on the fundamental review of incentives and development of longer term incentives.

We believe the current incentive framework is functioning relatively well, particularly with the improvements made to the models that underpin the scheme over the course of the 2013-15 incentive scheme period, albeit with some caveats. We recognise that there is some concern around the unusually high, year to date, constraint target for 2016/17. We wish to assure Ofgem and the industry that steps are being taken to address the issue; we will submit a proposed solution to Ofgem as permitted under the methodology statements.

When adopting a model based approach it is important to recognise its limitations. The model is simply an approximation to reality and as the complexity of managing the system increases, so does the difficulty in developing an appropriate model. Assumptions that were relevant in the past may no longer be appropriate due to system changes and will need to be adapted. These are not model errors and the changes simply recognise the rapidly changing environment in which we are operating.

It is also important to note that the mark to model approach does not reward a risk management approach to managing the system but instead rewards accurate forecasting of system out-turn, which, given the range of variables driving the system is not possible. Some of the uncertainty is managed through the application of ex-ante and ex-post variables. These have successfully focussed the SO on the areas where significant influence can be realised, as noted in Ofgem's consultation.

On balance, our opinion is that it is appropriate to continue with a model based approach for the interim. For this to be successful it will become increasingly important for Ofgem and NGET to recognise the limitations of the approach and work together to manage these.

We believe that, in the event of maintaining the BSIS framework, we should retain the mid-scheme update as provided by licence conditions. Whilst we understand Ofgem's view regarding a short scheme; we believe that, due to a fast changing market, the ex-ante assumptions made at more than a year ahead could risk windfall gains or losses under a modelled scheme.

We note Ofgem's view with regard to resolving model issues in a timely manner, and would welcome a mechanism which ensures the timely management and agreement of model errors for both the SO and Ofgem. In the same way, we would be keen to consider a formal process to close out a scheme after the financial year has ended.

Q1c. Do you agree that if we maintain the existing incentives framework during this period, we should seek improvements from the 2015-17 scheme?

We agree that, should we maintain the existing incentives framework, improvements should be sought from the 2015-17 scheme. As noted in Ofgem's consultation, the changing market environment, and incentive framework, has driven the SO to change its behaviour to deliver consumer benefit. Models and methodologies will require examination in the light of these changes to ensure they remain appropriate for use in the current, and future, environment.

A large part of the energy model uses regression modelling which is largely reliant on historic trends continuing into the future. The increasing management of risk and complexity of the SO's role, brought about by market changes, means that there are shortcomings in the reliance on historic trends. We are keen to implement model improvements but any changes should be targeted and limited in scope to reflect the relevance to a short term scheme, and to reduce the resourcing impact on the fundamental review process. We further welcome the opportunity to work with Ofgem and other interested stakeholders in those areas where Ofgem believes there is potential for improvements to be made to the current framework.

Chapter 3

Q3a. How could the BSIS target setting approach and modelling methodologies be improved in the short term?

We agree that, at the very least, a review of the methodologies which underpin the models is required for a new scheme. As part of this review, which will include a coefficient refresh, we would agree that there is a requirement to evaluate changing ex-ante variables to ex-post, and assess the significance of the regression variables.

As noted in Ofgem's consultation, the significant rise in embedded generation makes system forecasting increasingly difficult. The increase in decentralised intermittent energy on the system gives rise to more uncertainty for variables outside of the SOs control. It is our view that if a separate short term demand forecast incentive was introduced then it would seem prudent to change the demand variable from ex-ante to ex-post in the Energy and Constraints model. This would see demand forecasting rewarded more appropriately.

We also believe that, as mentioned in our response to Q1b, that a formalised timely close out process at the end of a scheme year be introduced. Given that a recent change to the licence allows for the impact of an error in any model on incentive performance, to be assessed up to 6 years later, it seems appropriate to have a time bound mechanism which formally ends discussions regarding performance in a particular scheme year.

Q3b. Do you believe the existing BSIS sharing factor and cap and floor remain appropriate?

We note that Ofgem are not minded to change the cap and collar or sharing factor; however, as in our response to the **Electricity System Operator 2015/17: Initial Proposals** we continue to believe that the cap and collar of £30m should be increased by at least RPI, otherwise the relative value is diluted.

We believe that under a short term incentive scheme it will be more difficult for the SO to realise benefits within the scheme period, as noted by Ofgem; therefore we think an increase to the cap and collar will further incentivise the SO to deliver consumer benefit in shorter timescales.

Given the increasingly complex nature of managing the electricity system, NGET's continual strive towards finding innovative ways to minimise costs and thus achieve performance under the scheme has delivered significant benefit to the consumer. The fact that the cap has either been hit or nearly hit, also suggests that the SO is not being appropriately rewarded for all the benefit delivered to the consumer.

It is for these reasons, we propose a further increase to the cap and collar above RPI to enable a reward, which is more appropriately aligned to consumer benefit delivered, to be achievable for the SO.

Whilst we recognise the sharing factor does not match the equivalent sharing factor available under RIIO-T1, we believe it provides an appropriate risk reward balance given the difficulties in balancing the system, as noted in Ofgem's consultation.

Q4. What is the best way to set an incentive on the SO to incur efficient costs when procuring Black Start from April 2017?

In the timescales relevant to this consultation on interim incentives we think that a financial incentive would continue to focus SO attention on procuring adequate economic Black Start services, provided that it reflects an appropriate risk / reward balance. We are keen to set the ex ante target for Black Start (Availability and Warming) in a more transparent manner. Given the current landscape with Black Start, it is right that the SO should target new, innovative sources for this service. We are exploring multiple new providers and there will be exposure to uncertainty around which of these providers will be capable of fulfilling Black Start needs. We therefore suggest that Black Start costs associated with Capital Contributions and Testing should join the same category as Feasibility Studies which are handled on an ex post basis. We suggest that the Black Start financial incentive should be set up on the same time horizon as the other parts of BSIS but that a mid-point review should be maintained. This would allow for provision of an update to targets for the latter part of the incentive period or to allow development of a viable longer term Black Start incentive commencing from 2018.

In the longer term we believe Black Start incentives require fundamental revision. The current scheme is exposed to significant market uncertainty. The short term one year time horizon fails to recognise the consumer benefits in terms of long term coverage and disregards the reality that much longer term measures need to be employed to achieve financial rewards. Certain elements of Black Start services are more suited to new transformational based incentive approaches run over a multi-year period. We are keen to explore the possibility of introducing a new longer term incentive on Black Start from April 2018, which would replace the April 2017 Black Start incentive, through engaging with Ofgem and industry on how to best address and incentivise the outlined current and future challenges.

Q5a. Do you agree that we shouldn't maintain the MDLC?

We note and with Ofgem's view that given the fundamental review for incentives will begin in 2017; there is no requirement for the current models to be continually developed whilst the review is ongoing. Removing the MDLC term will enable both NGET and Ofgem to focus on the fundamental review. Whilst we see it appropriate to remove the MDLC term, the methodology review referred to in Q3a will continue to obligate the SO to monitor and identify model errors for the current scheme.

Q5b. Do you agree that we shouldn't maintain the SO IRM? Are there any alternative ways to encourage innovative behaviour from the SO in the short term?

We agree with Ofgem that given the form of the IRM scheme and the proposal for an incentive scheme less than two years in length, it would not seem sensible to maintain a mechanism which cannot be fulfilled prior to the start of any new incentive scheme.

Whilst we do not have a similar alternative to suggest, due to the time required to put together proposals for delivery in a shorter scheme period, we reiterate our response to Q3b that an increase to the cap and collar would drive shorter term innovation by the SO in order to realise that benefit.

If we are to remove the SO IRM scheme, we would be keen to hear stakeholder views on whether the fund could be used elsewhere by NGET to deliver consumer benefit; for example, to encourage and enable new technologies / providers to enter the market.

Q6a. Do you believe there is a need for a new incentive on short term demand forecast from April 2017? How could this be designed? What timescales should it be based on: week ahead, day-ahead, hour-ahead, other?

We agree that system forecasting is becoming increasingly difficult as noted by Ofgem; however we would add that uncertainty has significantly increased during the overnight periods over the last year, this could possibly be due to changes in overnight behaviour and the increase in new technologies, such as electric vehicles. We agree that there is value in delivering accurate transmission system demand forecasts and, whilst Ofgem have provided examples of 2DA and 7DA demand forecasts, we are keen to hear stakeholder views on where the greatest value exists. We therefore agree that a new financial incentive would focus the SO to deliver improved system forecasts.

We would like to point out that the forecast demand in Ofgem's analysis does not equate to outturn demand. NGET is required[1] to forecast unrestricted demand in the timescales used in the analysis, whereas outturn demand will be restricted by such elements as Customer Demand Management (CDM) and triad avoidance. During the November to February period, this is likely to increase forecast error and create a bias towards over forecasting the demand.

[1] The Grid Code OC1.6.1 states the full list of factors that are taken into account for demand forecasts. OC1.6.3 determines which of these are included in forecasting National Demand.

There have been two significant changes post April 2015; prior to April 2015 7DA forecast used normal weather but we now use forecast weather, and we now update our forecasts every business day instead of only Monday / Thursday. These changes will have some influence on forecast accuracy.

We note Ofgem's proposal that a demand forecast incentive could be based on the current wind generation forecast incentive; however it is our view that the current error metrics do not take into account many underlying variables outside of our control which increase uncertainty. Such examples include those mentioned above, availability of data for embedded wind generation, capacity of connected wind and PV generation and errors within provided weather forecasts. In addition to code changes, required to access data at these embedded generators, significant investment would be required to translate this data into valuable insight. With this large number of variables outside of our control which impact significantly on the amount of uncertainty, we do not agree that this is a suitable approach.

We support Ofgem's view that responding to the challenges requires maintaining robust IT systems, dedicating resource to understanding system trends and investing to seek continuous improvements.

It is for these reasons we propose a more transformational approach to any new incentive on short term system forecasts; focussing on the work delivered by the SO to improve its forecasting rather than a simple error metric. We believe this type of incentivisation rewards the SO for determining the needs of the industry, and what it then delivers to meet those needs. This would enable us to focus on improving elements which we have control over, and incentivise us to innovate in the right areas to deliver value to the industry.

Q6b. Do you think there needs to be any changes to the wind generation forecasting incentive or new incentives on any other system forecasts?

For many of the reasons in our answer to question 6a, it is our view that the current wind generation forecast incentive cannot continue in its current format. We also highlighted in our response to Ofgem's consultation '**Electricity System Operator 2015/17: Initial Proposals**' that the performance metrics did not reflect an appropriate risk / reward balance particularly when the weather forecasts, which also feed into our generation forecast, often have errors greater than the error metrics for the incentive scheme. If it were to continue in a similar format we do not believe it would be beneficial to measure performance at a more granular level due to the challenges referenced previously; we would also propose that all SO actions are taken into account when calculating the forecast error.

We are also interested to hear stakeholder views on the value of the wind generation forecast; particularly in relation to what we forecast and when we deliver it. If significant value could be gained by industry and consumers, then given the levels of uncertainty and data available, we would propose an upside only incentive.

Q7. Do you think the SO's procurement of balancing services needs to be more transparent and open? If so, what steps should be taken? Should the SO pursue more market-based approaches? Should we introduce any incentives or requirements on the SO in this area from April 2017?

Whilst existing procurement of balancing services is in accordance with procurement guidelines developed and approved in accordance with the transmission licence, we agree with the principle that more transparency and openness could be provided by the SO regarding its procurement of some balancing services. We also support the view that the SO should increase its use of market based approaches where appropriate, however it needs to be recognised that not all services would benefit from a market based approach (e.g. some locational services will be delivered more cost effectively where the SO contracts directly with parties). We agree that greater transparency would be beneficial for the market as it will help sharpen investment signals, through price discovery, for participants to provide system flexibility at the right time and place to meet the SO's and other entities needs. Therefore we agree the SO should be incentivised to deliver improved transparency in service procurement where this is warranted.

As we move towards a more decarbonised and decentralised energy market, we see new technologies and market models wishing to offer services to the SO and other entities. Many of these new parties do not have as much understanding of the market as the more conventional providers. Traditionally, the SO had fewer providers, already present in the market and treating the balancing and ancillary services revenues as a top up. With balancing and ancillary services revenues now a key part of investment cases, both new and existing market players and technologies are increasingly reliant on the SO and the rest of the market providing more accurate investment signals.

The market in which we are operating is highly complex with many providers and widely varying needs. We are currently highly reliant on others' data. We do constantly look for ways to improve transparency. Given the scale of the task it is our view that in order to make our suite of balancing services more transparent and accessible to a broad range of providers, without restricting them based on product requirements, the introduction of a new work stream is required with the aim of enabling greater flexibility in the market, potentially over a set time period. In order to identify and understand the specifics of our stakeholder requirements around this need for increased transparency, we are in the early stages of delivering a customer survey to clarify the necessary areas of improvement.

Market participants have expressed concerns around the complexity and quantity of different services. It is our view that there are two main areas of transparency; the complexity around the different service types, and understanding how we assess tenders / provider suitability for a product.

With regard to different service types, whilst we note there are a large number of different balancing services, it is quite often the case that new similar services are needed, but due to slight differences in service requirements and contractual terms a new product name has to be established in order to differentiate the service from existing contracts. Bundling services together may cloud these requirements making it more difficult for a provider to understand tender rejection (non-acceptance) and subsequently value / price their service. Therefore we do not agree that bundling of services will necessarily increase transparency; however we do support the view that the SO could do more to reduce confusion around these services and increase procurement transparency.

We agree that the SO should consider a more widespread use of market based approaches through tenders and auctions. However it is our view that not all products may be suitable for auctions and or tenders.

An incentive could focus the SO to deliver against a measure over a number of years, rewarding us for facilitating providers, reaching a wider range of stakeholders, and fulfilling an enhanced role in providing investment and operational signals for market participants.

Q8. Do you agree with our proposed scope of changes? Is there anything else you believe should be changed, added or removed from the existing scheme?

We agree with Ofgem's view that the significant growth in intermittent and embedded generation, implementation of EMR and increased interconnection, have all impacted on the SO's role in managing the risk and costs of keeping the system safe, secure and balanced in real time; therefore requiring a fundamental review of incentives to ensure their appropriateness. We believe it to be an appropriate and prudent approach to introduce an interim incentive scheme on the basis of the existing framework, whilst the fundamental review is conducted.

Ofgem note in the consultation that the interim period would run from April 2017 until implementation of the new scheme in spring / summer 2018. However, we are keen to note that, in our view, the length of any interim scheme should have a specified end date to give certainty to the market. It is unlikely that the fundamental review could be carried out and new incentives developed by 1st April 2018. Therefore, it would make sense to run the interim scheme until the end of the 2018/19 financial year. This would ensure the SO continues to be incentivised during all of the 2018/19 financial year and would reduce the burden of re-writing significant portions of the Licence as many of the current incentive definitions are based on whole financial year periods.

We believe that the additional incentives for NGET are valuable additions to the main BSIS. The transmission demand forecast incentive drives us to improve our performance in the short-term, recognising that our forecasts provide certainty to the market, enabling participants to self-balance and respond effectively to price signals. Improvements to demand forecasts help mitigate rising system balancing costs as a result of increased intermittent and embedded generation. However, given our response to Q6a, we do not believe an approach similar to the wind generation forecast incentive is appropriate.

NGET support the principle of a transparency incentive and are keen to facilitate where possible, access to an increasingly decarbonised and decentralised energy market. Introducing an incentive to improve transparency will help focus the SO's efforts around market facilitation and enabling new providers to enter the ancillary services market.

As in our response to Q6b, we do not believe the wind generation forecast incentive can continue in its current format. We therefore propose its removal as a financial incentive or a fundamental review to include, but not limited to, stakeholder views on appropriate scheme metrics, time-horizon, timescales, energy or power forecasts, and where the value to the consumer lies within any forecast provision.

Appendix 1

Q9. Do you agree that there is a need for a mechanism that allows the SO to exchange funds with the TOs? Are there any additional pros and cons that we should consider in our analysis? Do you agree it should be introduced from April 2017?

We agree there is a need for a mechanism which can be used to reduce overall system cost, when an opportunity to do so is identified. Due to current structures and frameworks, the SO is unable to provide the TO with monies beyond current year which could be used to reduce total system cost. If such a mechanism were available, this would allow the SO and TO to collaborate proactively in planning timescales to identify opportunities where additional TO spend could actually reduce SO spend by a greater amount, which is ultimately to the benefit of consumers. Currently the SO and TO collaborate in planning timescales through the Network Access Policy framework to optimise outage plans, however there is limited opportunity within this process to inject funds to further optimise the economic cost of executing the plan.

Regarding pros and cons, we agree that a counterfactual approach to determining the actual savings of a particular action is necessary, and needs to be acceptable to all stakeholders. However, we believe that any perceived shortcomings of counterfactual analysis are outweighed by the advantages of implementing a mechanism which can deliver additional economic benefit to consumers.

We agree we should target the implementation of the scheme from April 2017, bearing in mind the requirement of completing any enabling licence/code changes within that timeframe.

Q10. Do you agree with the codified-approach?

We do not object to the codified approach per-se, and can see the appeal of this for the TOs with respect to the consideration of risk when delivering projects. We agree that aspects of the codified approach, such as building on the existing coordination via the STC and NAP, and introducing an STCP to define the mechanism is a prudent method of introducing the scheme. However, a key feature should be the ability for the SO to agree a fixed price with the TO in advance, this gives greater certainty of costs, which would aid the SO in making a decision to proceed with a course of action that is forecast to make savings greater than the investment. Our concern with not being able to fix a price in advance with the TO, is if incurred TO costs increase over the value used to justify the decision to go ahead with the works, then the forecast savings could be eroded, ultimately resulting in lower/negative realised savings.

Q11. What do you consider to be the most appropriate cost recovery levy methodology?

We believe the simplest and most transparent method of cost recovery is as described in paragraph 43, i.e. to spread the cost evenly throughout the yearly period of BSUoS charge, utilising a similar principle to that used in the existing STCP 11.3. This would fit with the increasing feedback from BSUoS payers wanting greater certainty of costs in advance. It also removes any subjectivity if trying to determine precisely when consumer benefit is realised, particularly if the mechanism were to be used for initiatives other than constraint cost management (different types of project potentially delivering benefit in different timescales).

Q12. Do you agree with the proposed approach with regard to the financial aspects of the mechanism outlined above?

We agree that building upon a combination of frameworks already in place (e.g. STCP 11.3 and BSIS) would be a practical position from which to test this proposed mechanism: A pre-agreed ‘pot’ to utilise for investment, partnered with a risk/reward/ scheme on the SO responsible for demonstrating net cost-savings. We also agree that for certain cases such as high-cost capital investment delivering benefit over many years, then TNUoS may be a more appropriate charging vehicle.

Q13. Do you agree with our proposed investment threshold for Ofgem approval?

The proposed investment threshold appears to be at a sensible level to test the mechanism. We believe that monitoring the scheme regularly to understand how it gets used in practice will inform the levels at which thresholds should be set. For example, the funding ‘pot’ could be reviewed to ensure the SO does not run out of funds during the year, even if there are further savings/investments identified.

Q14. Do you think the costs incurred through a mechanism should be incentivised as part of an overarching financial target on balancing costs, or as part of a separate financial incentive?

Financially incentivising the SO will provide a governance mechanism to protect BSUoS payers from being charged for additional works which do not provide economic benefit. A scheme separate to BSIS will ensure that relevant parts of the SO will focus on demonstrating positive performance against the explicit incentive. Separation from BSIS will enable greater transparency and clarity of value delivered. Separation from BSIS also means that the length of this scheme is not dependent upon BSIS running in parallel. We recognise that using this model will need measures put in place to ensure the SO is not rewarded for the same action both via BSIS and the new mechanism.

Q15. What, if any, impact will limiting the mechanism to the end of RIIO-T1 period have on efficiency of potential projects that cover both RIIO-T1 and RIIO-T2 periods?

It would seem prudent to allow the scheme to encompass any scenario where potential cost savings are identified, including SO requests for the TO to deliver additional works/services which span the time boundary between RIIO-T1 and T2.

Q16. Are there any other criteria we should consider for such projects?

We have not identified any other criteria for those potential projects, however we believe if the mechanism is successful then it could be extended into RIIO-T2. Due to the numerous uncertainties present when planning ahead in an eight-year time-frame, it seems inevitable that not all economically optimal whole-system solutions will have been identified prior to the start of the regulatory period, and this scheme can potentially help to reduce total cost of system operation for unforeseen/changing scenarios within the regulatory period.

Q17. What level of transparency would you want regarding this mechanism?

Transparency of this mechanism would be enhanced through having the scheme as a stand-alone entity, making its value simpler to separate from other System Operator incentives. We agree that within the scheme, for actions taken by the SO there should be transparency around items such as forecast savings, forecast costs, actual savings, and actual costs. The methodology used by the SO to determine the counterfactual savings should be clear, and appropriate for each instance.

Q18. Do you consider that we have identified the changes required correctly? Are there any other changes required to the existing framework in order to implement the mechanism?

There could be a requirement to add any new BSUoS terms or modifications into CUSC section 14.30 “Calculation of the Daily Balancing Services Use of System charge”, to map to any changes made in the Statement of Use of System Charges.

Q19. Are there any other factors that you think we need to consider in the design of the mechanism?

This comprehensive consultation covers the relevant factors needed to design this mechanism, and we look forward to discussing further with Ofgem and other stakeholders.

We think a pragmatic approach to the introduction of the scheme would be to pilot it for a period, and then review its performance, modifying the parameters where necessary based upon the review.

If you would like to discuss this response further, in the first instance please contact Audrey Ramsay (audrey.ramsay@nationalgrid.com or 01189 363633).

Yours sincerely

[By E mail]

Cathy McClay
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