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Dear Leonardo

We welcome the opportunity to respond to the consultation on **Initial Proposals for electricity System Operator incentives from April 2017** that was published on 21 December 2016. We have addressed our response to the specific questions posed by Ofgem in the Appendix, which broadly reflects our initial views expressed in response to Ofgem's consultation on Electricity System Operator incentives from April 2017, on 15 September 2016.

We agree that it is in consumers' interests that a shareholder-owned transmission system operator should be incentivised to perform and innovate to drive costs down whilst managing risk on behalf of consumers, when it is best placed to do so. Furthermore these incentives, across the portfolio of activities undertaken by the System Operator, should have symmetrical risk and reward opportunities to ensure alignment of shareholder interests with that of consumers. The proposed approach to Black Start does not provide such a balanced approach. We have offered an alternative that maintains the principle of balanced risk and reward. We are open to other approaches that provide this overall balance and work in the interests of consumers.

The range of the risk and reward and the sharper sharing factors of recent schemes have incentivised the SO to manage greater risks on behalf of consumers. These include new contracting structures that have required longer term investment beyond the incentive scheme term and introducing new services from new providers. This has enabled the SO to transform its activities further and at a faster pace than envisioned in RIIO-T1. This has been necessary to operate the complex energy system delivered by the accelerated decarbonisation of the energy market while keeping costs down. As the market and the system is evolving at an rapid pace, it is appropriate that the SO should continue to be encouraged to manage risks of behalf of consumers by maintaining the range and sharpness of the incentive scheme.

We believe that the existing BSIS framework with the suggested model improvements and the addition of proposed new incentives will ensure a strong focus is maintained on driving down balancing costs through continuous improvement and innovation. The appendix to this letter addresses the specific questions raised in the initial proposals document.

Yours sincerely

Cathy McClay

APPENDIX 1: ANSWERS TO SPECIFIC QUESTIONS

Chapter 2: Balancing Cost Incentives

Q1. Do you agree with our proposals to introduce new licence requirements/guidance around SO balancing behaviour? Please explain your answer.

We welcome the development of a common understanding of 'economic and efficient' system operation in the emerging context of the GB energy system. However, we need to ensure that this does not result in prescriptive governance, which is not aligned with incentive based regulation. This would focus our attention on meeting the requirements of Ofgem rather than primarily on delivering savings to the consumer. The additional requirements for governance and oversight need to be clear and adaptable to ensure they improve the quality of oversight and contribute to building confidence in the process, otherwise there is a risk of undermining confidence, creating regulatory uncertainty and in doing so adding inefficiency into the process.

We have two main concerns regarding the proposed refined definition of 'economic and efficient' – a long established requirement in the Electricity Act and reflected in the network licences. Firstly the proposed amendment appears to extend our current obligations in terms of reporting and distribution network considerations; if this is to be done, then it is suggested that this should be done as part of, and in the context of, the wider Future Role of the SO discussions rather than as part of the BSIS 17-18 incentives arrangements. Secondly, the description of balancing behaviour considerations sets a benchmark which could be unnecessarily onerous to demonstrate compliance against. The need to satisfy ex-post examination of this condition risks establishing a new incentive to balance in a manner which minimises challenge with the benefit of hindsight. Close prescriptive direction on how the SO must operate could unintentionally constrain innovation and stifle new ways of operation which deliver value to the end consumer. To avoid this potential conflict careful wording is required so that it remains consistent with primarily ex ante regulation and incentives.

Q2. Do you agree with the clarifications we propose to introduce to NGET's licence? Is there anything missing or that should be removed? Please explain your answer.

We support the principle of introducing the clarifications, but as mentioned in the response to question 1 we have concerns around the inclusion of additional activities not currently undertaken by National Grid as system operator and the ambiguity of the proposed changes.

We do not support widening the responsibilities of the system operator ahead of the Future Role of the SO consultation which is currently underway. Reference made to **"the impact the action would have on the whole system efficiency, including on frequency and voltage patterns of distribution network….."** would appear to add to our role as Transmission System Operator, as although frequency is monitored and controlled constantly and, save during transients, is the same at all points across the transmission and distribution networks, voltage patterns on distribution networks are not currently the responsibility of National Grid, and so reference to DNO voltage should be removed. Whole system efficiency needs clarification, as this relates to effective collaboration between the Transmission Owners and System Operator within the Network Access Policy document. However there is currently a proposal to expand this to include Distribution Network Operators as part of Whole System Operation under the Future Role of the SO.

The proposed changes to the SOs overarching duties to be efficient are unclear. For example, the change from 'efficient' to '**most efficient**' suggests an unclear but tighter threshold than simply 'efficient'. The existing licence drafting provides Ofgem with full powers to review the reasonableness and efficiency of the actions the SO takes against efficiency criteria. Therefore the change adds nothing to Ofgem powers but, without further clarification, adds significant uncertainty into the SO's objectives for the SO and for balancing service providers who need to understand our decisions.

The phrase, 'ensuring procurement of balancing…. services is **as transparent as possible**' is not an objective measure and so raises the risk of excessive reporting being introduced to prove this obligation has been met.

Q3. Do you agree with our Initial Proposal of maintaining a model-based target from April 2017 until March 2018? Please explain your answers.

We support the continued use of the target setting models for BSIS. This is a key element of creating arrangements which agree in advance how risks, many outside the control of the SO should be allocated and shared with others in the market. The models attempt to set the target baseline cost of balancing the system in an economic and efficient manner reflecting the effect of transmission system conditions which may impact balancing. When representing the transmission system in a model, simplifications and assumptions must, of course, be made. As the operation of the actual system changes, it is inevitable that some of the simplifications and assumptions will no longer be valid and that the model may need to be adapted to reflect the new situation.

It has taken longer than would be desirable to resolve 'errors' identified in the 2016/17 model due to the complexity of the data involved. It should be noted that the majority of these 'model errors' have been due to the challenges in keeping the model assumptions aligned with the complex and changing operation of the system which has increased significantly with the growth in embedded generation and as such they are more 'model updates' of assumptions than 'model errors'. When representing the transmission system in a model, simplifications and assumptions must be made. As the operation of the actual system changes, it is inevitable that some of the simplifications and assumptions will no longer be valid and that the model must be adapted to reflect the new situation, as has happened in previous years.

The term 'model error' requires clarification within the licence as 'error' implies to the industry that a mistake has been made rather than the assumptions within the model have had to be updated to align with changes in system operation.

Working together with Ofgem, we have also identified four significant areas where the model will be enhanced for 17/18 to provide increased transparency and simplicity whilst reducing potential windfall gains and losses. The inclusion of the listed improvements in relation to demand and constraint limits not only seek to rectify windfall gain/loss opportunity but seek to build into the baseline SO target costs all of the benefits provided by daily SO activities.' Discount factors, originally included to take account of 'business as usual' optimisation, need to be amended to take into account the proposed modifications to the modelled scheme.

The proposed additional governance process should further add to the confidence of a modelled target approach, although we note that specifics on obligations and timelines need revision to be workable given the time modelling revisions take to test.

Against this backdrop, a scheme with sharp incentives for the SO would work well to further align SO interests with those of consumers and encourage proactive, innovative behaviour to deliver further value.

Q4. Do you agree with our proposed changes to the governance and incentive parameters? Is there anything missing or that should be removed? Please explain your answer.

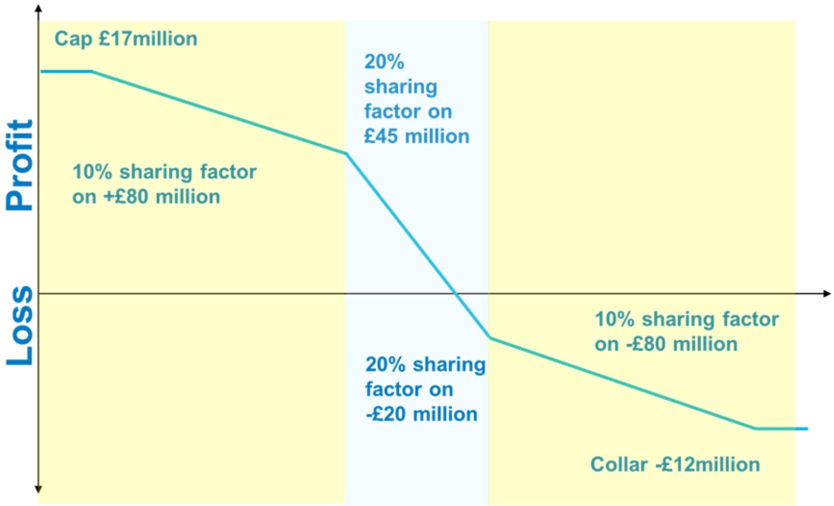
We are committed to doing the right thing and to operating the system in an efficient, economic and coordinated way that realises benefits for consumers. The accelerated decarbonisation of the energy system, with increasing amounts of distributed, renewable generation has required us to transform our activities further, and at a faster pace than envisioned in RIIO-T1. We have developed new, innovative operational and contracting approaches with traditional and non-traditional service providers to manage the new challenges in delivering transmission system security while minimising any increase to balancing costs. We have invested in new contracting structures beyond the incentive scheme term because we consider it is the right thing to do for consumers. We welcome your recognition of what we have achieved in your recent consultation on the future role of the SO.

Nevertheless, this has increased our exposure to risk without a corresponding opportunity for reward. Incentives are a mechanism to enable us to make decisions and share outcomes with consumers, and to mimic the drive to innovate and continuously improve that is faced by entities in a competitive environment. In designing the incentive scheme for 2017-18, as well as the incentive framework for the SO from 2018 onwards, it will be important to avoid dampening this drive through reducing the potential reward available whilst we manage increased risk on behalf of consumers. This would support our shared vision for a smart, flexible energy system enabled by a proactive and innovative SO.

We understand and support the use of incentives to deliver benefit to the consumer through alignment of SO behaviour with consumer needs. We recognise that the proposed changes to the governance and incentive parameters give a lower probability of hitting the cap. However, the low cap and low sharing factor proposed by Ofgem, potentially weakens the incentive on the SO, reducing the impetus to drive innovation and efficiency and consequently may restrict the benefits for the end consumer. Incentives best serve the end consumer when they place a sharp focus on performance with an appropriate risk reward balance.

In order to deliver symmetrical risk and reward across the whole incentive portfolio proposal, taking into account Black Start Disallowance, we propose an asymmetric cap and collar with stepped sharing factor on BSIS which will provide a stronger incentive for the SO. For example, BSIS would have a cap of £17 million and a collar of £12 million to balance a Black Start disallowance collared at £5 million.

This would have a sharper 20% sharing factor over the first £45 million over-performance and first £20 million underperformance against the target which then changes to a 10% sharing factor for the following £80million of over or underperformance. This delivers value to the consumer over a £100million or more range in the same manner as the proposals, whilst providing a stronger incentive on the SO.



We agree with the need for improved governance in order to provide structure and consistency to the management of BSIS as well as to support the ongoing relationship with Ofgem and industry stakeholders. We acknowledge that it is challenging to keep models aligned with a rapidly changing system, but, this should not result in a lack of trust in a modelled scheme. The improved governance will provide assurance that processes are in place to ensure changes are made in a timely manner. The governance framework as proposed contains elements which could be simplified to deliver the required outcome, recognising it is for a one year scheme, and that it should not be so onerous that we focus on the regulator at the expense of delivering additional benefit to consumers. Proportionate administrative burden on both the regulator and the regulated business is needed. We support the aim to deliver the information which Ofgem needs. We also support the aims to introduce timeline requirements around Incentives which better supports the market. However, there are some practical time limitations which should be considered with respect to governance in order to make a framework practical to support stakeholder needs and the SO/Regulatory working relationship.

Any occasion when the models produce a target not appropriately reflective of true system operation balancing spend is currently described as a 'model error'. In discussing incentives with industry participants it has become clear that this term is confusing. Even though the term 'model error' is defined within the incentives scheme, the commonly held view in the industry is that a 'model error' is a mistake made by National Grid. This is undermining industry confidence in the use of models within the incentive scheme and in the capability of National Grid. Whilst some 'model errors' are due to mistakes, the majority are due to the fact that complex models in a changing environment require ongoing revision to keep the outputs true. We therefore propose that we replace the term 'model error' with 'model update'.

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Given the 'model errors' experienced in 16/17 we understand Ofgem's requirement for a mechanism to rapidly address concerns where model performance is significantly different from actual balancing spend. We support the provision of a backstop in BSIS but the application and criteria must be pragmatic and well balanced so that it offers a safety mechanism for consumers but that the requirement on National Grid to provide evidence is not too burdensome. However, focusing on the modelled target alone would not provide a meaningful measure as it is driven by structural factors that change with time, and so could result in numerous occasions where a backstop provision is erroneously applied. A backstop provision which stops the incentive scheme creates significant uncertainty for BSUoS payers and National Grid, and could result in a System Operator focussed on the provision of evidence to the regulator rather than on delivering innovation and efficiency, which would not be aligned with the interests of the consumer. Instead, we propose monitoring the difference between modelled target and outturn which would highlight areas of significant under or over performance and trigger a process for rapid resolution of 'model errors', if the performance could not be justified by National Grid. We advocate the use of this different approach in setting backstop threshold measure detailed below.

- Monthly Target Cost-Monthly Outturn Cost= Difference D
- Use monthly data 'D' from 2011 to 2016 as basis of historical comparison
- Set threshold limits on historical 'D' as a band to represent between 2.5% and 97.5% (equivalent effect to 2 Standard deviations)
- If 17-18 BSIS monthly difference 'D' exceeds these threshold levels then backstop actions would be triggered
- Note that monthly targets normally have some variation in the following months due to data availability timing and reconciliation.

A scheme which has the potential to 'fall away' at any point through the year creates financial uncertainty for BSUoS payers, and National Grid. Effective discussions between the System Operator and the regulator in the event of significant under or over performance in order to understand the reason for difference between target and outturn, prior to enacting a backstop provision are essential to mitigate this increased level of financial uncertainty. We propose that if the scheme was put on hold it would be re-instated after timely resolution of any issues and targets would then be created for all months.

In addition to this we propose that the Incentive performance is adjusted to the pro-rated monthly cap and floor if performance is outside the threshold with no acceptable justification or model resolution in an acceptable timeframe. Adjustment of the BSIS target from above the cap to zero is unnecessarily penalising especially where the BSIS target set is just above the threshold and may incentivise behaviour which is not in the interests of consumers.

We support the Final End of Year reporting requirement but propose a date of 1st June as all data is not available to meet the date set in the consultation of 1st May. Two 'End of Year' submissions are proposed for BSIS, first in June 2018, then in 2019 after final reconciliation is completed. We do not see the need for an ex-post audit as the additional governance measures introduced in the interim incentives proposals negate the requirement for this at the end of the 2017-18 BSIS year.

Chapter3: Black Start

Q1. Do you agree with our proposal to remove Black Start from BSIS? Please explain your answer.

Our preference is to retain Black Start in the BSIS scheme as we believe that this delivers the best value for consumers. However we understand the current difficulties of setting an appropriate target for the availability costs. Our proposal is therefore to retain the black start warming costs within the BSIS target whilst applying a modified disallowance scheme to the availability costs.

The disallowance scheme needs to be underpinned by clear principles and policy agreed with Ofgem, against which we will then procure and manage Black Start capability. A standard that is set by BEIS would add clarity and support this in principle. We are happy to support further work with Ofgem and BEIS to consider this. This will not be in place for April 2017 and all purchases prior to this date will be assessed solely against the economic and efficient licence condition, so there is a risk that costs considered economic and efficient by National Grid will be disallowed under the scheme.

The potential magnitude of the disallowance under the scheme exceeds the total reward available across all of the proposed incentives. This, coupled with the ambiguity regarding economic and efficient, exposes National Grid to disproportionate risk. This is not in the best interests of consumers as it focuses our efforts on providing evidence to the regulator and defending decisions rather than on delivering innovative black start solutions for future years. We propose that Black Start warming costs should remain in the BSIS scheme for two reasons. Firstly, it is relatively straightforward to set a target for these costs. In addition, it is normal for units being warmed for Black Start to provide other services such as voltage support and reserve, as this reduces costs to consumers. The current BSIS scheme has a cap and collar on the potential profit and loss for National Grid under the scheme and any savings or losses are exposed to a sharing factor. A key rationale in the consultation for removing Black Start from the incentive scheme is that it is difficult to set a target for the scheme rather than as a result of a view that the current risk profile is inappropriate.

The proposed disallowance scheme places a strong impetus on National Grid to negotiate to ensure an economic and efficient outcome. However, it must be recognised that the factors driving the scale of costs in this area are entirely out of our control and it would therefore be inappropriate to place unbounded downside risk on us. The disallowance scheme should therefore be designed with a mechanism to rectify this. In order to deliver an incentive portfolio proposal with symmetrical risk and reward, we propose a £5million collar to balance our asymmetrical BSIS proposal.

Q2. Do you agree with the principles of our Black Start regulation? Should we add of remove any principle? Please explain your answer.

Yes, the high level objectives should enable the SO to identify the correct capability requirement and to procure black start efficiently. However, we have a number of points of clarification and proposed modifications on the principles that Ofgem has outlined.

1. Clear Robust and technical decision making

We agree with this principle and believe that the decisions taken should be validated with clear assessments which demonstrate technical capability and/or value to the end consumer. We support the creation of a black start strategy and a procurement methodology so long as they are underpinned by an ex-ante, clear, transparent black start standard set by BEIS that both National Grid and Ofgem can use. This is an essential pre-cursor to the scheme.

2. Diversification and optimisation of restoration approach
As the generation profile changes, the way in which restoration is carried out needs to adapt to remain achievable. Over the past year, we have been proactively seeking new providers and we recognise the need to continually engage to ascertain what potential providers exist. The restoration strategy should be flexible enough to be adapted continually to include new providers and new technologies and there will be a requirement for funding of feasibility studies. This expenditure will need to be justified against the diversification criteria.

3. Transparency of approach procurement, and service status
We have recognised the need to be more transparent in our approach to procurement. Feedback to date has highlighted that information on black start requirement by location, technology type and expected rate of return would be useful. We support the provision of more transparent requirements, however this needs to be balanced against system and security risks and we would be concerned about publically identifying individual providers. Areas of further transparency could be around the restoration strategy, zonal requirement and a forecast of requirement for future years.

4. Flexibility of approach for the licensee
Flexibility is key to delivering a sustainable Black Start policy and restoration strategy so long as it is underpinned by a clear, transparent black start standard. Costs will be incurred in running trials or testing of potential new providers and the SO would seek reassurance that these costs would be captured as part of developing the service and that they would be deemed efficiently incurred even if that did not lead to a new service provider.

5. Efficient costs
We wholly support this principle, however the definition of "efficient costs" would need to be underpinned by an ex-ante, clear, and transparent black start standard. Any efficiency test could only be made based on the information that we had at the time of making the decision. The introduction of new Black Start services takes several years in the planning, assurance, design and construction and we may need to commit to costs on projects significantly in advance of the time frame in which they will deliver.

6. Consistent standards across GB
As already mentioned, there is no ex-ante, clear, transparent black start standard set by BEIS that National Grid and Ofgem use. This is an essential pre-cursor to the scheme. It is possible that the Black Start Working Group could facilitate the production of such a standard but it is not likely in the timescales prior to the 2017/18 scheme. We can commit to work with BEIS and Ofgem to agree what constitutes 'adequate levels of protection for GB'. This will therefore drive the procurement requirement for the foreseeable future and therefore should be open to change when a standard be established.

7. Optimal integration of BS in the wider policy framework
As stated earlier we will warm, and potentially synchronise, a unit for more than one operational requirement. Although these units may provide multiple services each one is assessed separately on their submitted prices. This allows us to ensure we are procuring on a lowest total cost basis to maximise value for the end consumer.

8. Promotion of competition
Competition will drive more efficient costs and enable alternative restoration options to be considered and transparency should encourage expressions of interest in this area. It can take up to 4 years to get a potential provider to a point that it can offer terms. Therefore in order for the

market to be liquid there needs to significantly more providers in that position than the identified requirement. This is compounded by the fact that the service is regional, not national and so locational factors can also limit liquidity. Therefore tenders may need to be signposted at considerable lead times with acceptance that feasibility studies and other preparatory costs will need to be funded outside of that process.

9. Minimising distortion in wider markets

We seek to minimise market distortion when making procurement decisions. However, where one provider is offering multiple services the fixed costs of their asset will inevitably be recovered across returns on all those services. Whilst we accept that providers may leverage contractually firm, or likely, future revenues from an existing service to influence their price in other markets it will be very difficult to remove that completely. Black start service provision can be capitally intensive and have long lead times to market entry. If such providers were excluded from participating in other markets it may will lead to significant consequential costs to the consumer as providers look to recover all their costs via a single service.

Q3. Do you agree with our proposed regulatory framework for 2017/18? Please explain your answer.

We support a scheme which offers longer term incentives for Black Start and recognise that 2017/18 is a transitional scheme allowing the development of a longer term framework and incentive scheme. However this transitional year approach must balance risk and reward in order to drive the correct behaviours and the uncapped downside risk associated with the proposed disallowance approach does not achieve this. The proposed approach incentivises us to be more risk averse to investing in new services during a time when increasing investment is needed. Therefore, a capped cost exposure with sharing factors comparable to the incentive scheme would be more appropriate. While we agree with the proposal to publish a strategy and procurement methodology we are concerned in what timeframe this can be practically implemented. In an ideal world an agreed black start standard would be set by BEIS which would provide further clarity to allow us to understand the trade-off between cost and restoration time. We would then develop our strategy to ensure that this standard was met and then develop a procurement methodology which would outline how we intend to procure against that strategy. All three are needed to work together. In the absence of a standard at the outset of the scheme any costs incurred in 2017/18 prior to the agreement of the strategy and procurement methodology should be judged against the ‘economic and efficient’ criteria.

Chapter 4: Forecasting Incentives

Q1. Do you agree with our amended wind generation forecast incentive proposal? Are there any elements you feel should be changed or that are more relevant to you? Please explain you answer.

The provision of an accurate wind generation forecast is an important component of the overall demand forecast, which ultimately drives lower costs to consumers through increasing the certainty with which market participants and the System Operator balances their positions. During the period 2013 – 2016, installed wind capacity of metered generation forming part of the incentive scheme increased from 7.2GW (Apr, 2013) to 11.2 GW (Dec, 2016). In addition, unmetered embedded wind capacity rose from 2.1 GW to 5.1 GW in the same timeframe. 2016 also saw a number of records set such as the highest recorded level of wind generation (7,911MW, 23rd December 2016) and 106% of Scottish demand being met by wind generation (7th August 2016).

The accuracy of the wind generation forecast is driven by two elements: the accuracy of the underlying wind speed data and the conversion we make of the underlying wind speed data to both MW generation and the underlying demand forecast e.g. a 10mph increase in wind speed in cold conditions can add up to 1GW to transmission demand.

We currently procure our main weather forecasts for electricity demand forecasting purposes from the Met Office. The Met Office states that "The World Meteorological Organisation compares similar statistics among national meteorological services around the world. These show that the Met Office is consistently one of the top two operational services in the world."[1] Despite this, there is still a reasonable proportion of the error in the wind generation forecast that can be attributed to errors in the underlying weather forecast.[2]

We continuously identify and progress projects to improve our forecasts and minimise the error in the wind generation forecast and will continue to do this. Our projects in this area include updates to the wind power curves that are used within our forecasting model and a research project looking at modelling the impacts of high wind shutdowns.

Whilst we are continuing to work with the Met Office to improve the underlying forecast, this will still account for a reasonable component of the final error and it is something over which we have little or no control. It is also important to consider the feedback we have had from stakeholders which is that as well as valuing accuracy in our forecasts, they also value transparency of the different components that contribute to our overall forecast. We therefore propose that stakeholders would find it useful to have access to a forecast that covers both embedded and BM-wind[3].

In light of these points we are proposing an amendment to the existing incentive, where the scheme scope is widened to also include embedded wind and as a result the winter and summer targets are both increased by 0.5% to reflect the increased complexity of forecasting embedded wind for which we have no site specific data. This amended scheme provides a benefit to consumers as increasing the transparency of the forecasted position of all wind generation should increase balancing efficiency.

[1] https://www.metoffice.gov.uk/about-us/who/accuracy/forecasts

[2] Please see Appendix 3 for a review of met office accuracy

[3] Wind generators that are registered as a Balancing Mechanism Unit on the transmission system

Q2. Do you agree with our proposal to introduce demand forecasting incentives in this interim scheme? Are there any elements you feel should be changed or that is more relevant to you? Please explain you answer.

Energy forecasting has become more complex in recent years as underlying demand has reduced, the penetration of renewable generation has increased and embedded generation has resulted in lower demand evident at the transmission level. We agree with Ofgem that short term forecasts are vital for balancing efficiency.

Ofgem's consultation noted a bias towards over-forecasting demand. The demand forecast is an important input to the National Grid Control Room to manage the system in real time and ensure Security of Supply. When the system margin is tight the consequences of under forecasting are much more costly than of over forecasting and in extreme circumstances could lead to a demand loss event. From a risk management perspective, when the system is tight and/or there is uncertainty around the forecast, the prudent approach is therefore to forecast slightly long as this protects against the extreme prices which could be experienced. This is the same approach taken by the supply companies when contracting for their own portfolios. Under the dual price cash out, the cost of being short could be much higher than being long and so there was a tendency to be slightly long.

Over recent months we have been seeking views from stakeholders that use our forecasts in order to understand what those stakeholders find useful and where we should prioritise our improvement efforts[4]. The main points in their feedback are:

- Nearly all respondents described our forecasts as critical to them, either in terms of the forecast themselves or in the other areas the forecasts feed into, such as the decision to issue Electricity Margin Notices or de-rated margin calculations
- Small companies cannot afford to purchase demand forecasts and so without the free National Grid forecasts, would not have been able to enter the market
- Many respondents want greater visibility of customer demand management[5] (CDM) / Triad avoidance forecasts
- There is a desire for maximum possible clarity, breaking down our forecasts into the individual components

Based on the above points we propose that the high level principles that should apply to any demand forecasting incentive are:

- The objective of the incentive should be to facilitate efficiency in balancing actions by market participants and the system operator
- The incentive should cover timescales that are valuable to stakeholders
- The target level of accuracy should be challenging for us to achieve, in order to drive innovation in the approach to demand forecasting, but should be cognisant of the proportion of the error attributable to the underlying forecast error and the ability to make significant changes within a one year timeframe
- The incentive should be measured against the same data against which the market and System Operator balances in real time, in order to drive balancing efficiency.

[4] Please see Appendix 2 for a summary of the stakeholder responses received

[5] Specific actions taken by transmission connected demand or distribution connected demand or generation to reduce consumption at the transmission/distribution grid supply point at times of high market prices

Q3. Do you have any additional criteria that you would propose for the Quarterly Forecast Report? Please explain your answer.

We support the introduction of a quarterly forecast report as a means of increasing transparency. It is important however that this report does not become over burdensome to either produce or read, in which case it will become less useful to its intended audience.
Therefore we propose that the report contains the following:

- Actual demand and forecast demand per settlement period for within day, day ahead, 2 days ahead and 7 days ahead, broken down into restricted and unrestricted demand[6], embedded PV, wind and underlying demand
    - This differs from Ofgem's proposals by restricting the timeframes covered to those that are incentivised, reflecting that these are the timeframes that stakeholders have said are valuable to them
- The above data converted to provide the % of forecasts that are over or under forecast compared to outturn, with an indication of the most prominent reasons e.g. underlying weather error
- Metered wind unwound for BM actions in order to demonstrate the impact that Bid Offer Acceptances (BOAs) have on wind generation output. This data should cover the 4 hour ahead time frame as BOAs are only issued at a maximum of 89 minutes' notice.
- A list of the underlying reasons causing forecasting errors and mitigations or improvement projects that are being undertaken to mitigate them

Q4. Do you agree with how the parameters for the incentives are calculated? Should we consider anything else when setting the target?

We agree with Ofgem that short term demand forecasts are vital for balancing efficiency. Accurate forecasts allow participants to better self-balance and the System Operator to plan more efficient balancing actions, both of which lead to lower costs for consumers. We have reviewed Ofgem's proposed incentive structure and have some concerns about its ability to incentivise the right behaviour. We have sought advice from a third party in order to gain an independent review of the proposals.

National Grid review of Ofgem proposals
The proposed accuracy incentive requires use of settlement data to measure outturn. The incentive is driving efficiency in balancing of market participants and therefore should be based on the data upon which decisions in operational timescales are made, which is operational data.
The proposed scheme implies that forecasts are measured against restricted demand outturn, i.e. taking into account the actions of demand and embedded generation in response to high prices. Whilst we agree that it is of benefit to the market that our view of restricted demand is made available with our forecast, we do not agree that it would be appropriate to incentivise this forecast. There is no means of accurately measuring how much of a price response is seen on any one day as it relies on knowing what the counterfactual situation would have been.
In setting accuracy targets, a scientific approach to what is achievable in the future should be taken, rather than, as in the proposal, a value based on historic data because changes to the electricity system, particularly the capacity of unmetered generation, both weather-driven (wind and solar) and other, means that historical performance is not a good indication of what can be achieved in the future.

[6] Although it must be recognised that any market participants' actions to reduce demand or increase consumption on the distribution network in response to high prices can only ever be estimated

The proposed scheme uses relative accuracy as a measure of performance. Absolute accuracy should be utilised instead, as this incentives us to focus on times when demands are high which is in line with what stakeholders would value the most. The scheme as proposed sets stringent targets that are beyond what could realistically be assessed as challenging targets for improvement in a one year timeframe. This will not serve to incentivise innovative behaviour. The proposed bias scheme is sensitive to very small changes in demand data. There should be a deadband representing the inaccuracy of demand metering, giving a quantitative value to 'small changes', the size of which would be different for different forecasting time horizons, as what would count as a small fluctuation would depend on how far ahead the forecast has been made.
We propose:

- +/- 100MW is suitable for day ahead forecasts
- +/- 150MW at 2 day ahead; and
- +/-300MW at week ahead

Bias should only contribute to the performance if it lies outside this deadband.

Further details on our review of the Ofgem proposal is given in Appendix 5.

Smith Institute Review of Ofgem Proposals
We have engaged the Smith Institute[7] to carry out a review of Ofgem's proposals. Their report is included in Appendix 6. A summary of their conclusions is included below:

- The forecast error experienced at any one point is determined jointly by any shortcomings in our model and by any errors in the input to the model. The incentive proposals do not distinguish between model and forecast errors.
- We are in a much better position to control model error than to control input error. It would therefore seem reasonable for National Grid's incentives, particularly in a one year timeframe to be targeted at reducing model error.
- The errors in linear regression models are naturally symmetric in cases like National Grid's models, where they do not involve any mathematical transformation of the quantities being forecast. The proposed symmetry incentive can easily penalise a perfectly symmetric model, especially through the focus on individual cardinal points. For example, if 30 forecasts are made in a month for a particular cardinal point then with probability in excess of 2% there will be either at least 70% overforecasts or at least 70% overforecasts, even if the error in each individual forecast has probability exactly one half of being positive and one half of being negative. Any such event means the maximum penalty is incurred in that month. If there are 10 cardinal points being forecast each day, as in the winter, then the probability of some cardinal point triggering the maximum penalty is more than 18%. So in 18% of winter months the maximum penalty will be applied, even if the model has no error asymmetry at all. In summer months, when there are 12 cardinal points, this rises to more than 21%.

National Grid's Incentive Proposal
In light of the above points, combined with stakeholder views on what is valuable in a demand forecast, National Grid has built on Ofgem's proposals in order to develop an alternative incentive scheme detailed in Appendix 4.

Q5. Do you believe we should introduce an additional mechanism to counter the incentive to under or over-forecast in any given month to maximise incentive value? Please explain your answer.

[7] The Smith Institute provides mathematical consultancy for industry, business and government.

The purpose of this additional mechanism is to avoid National Grid purposely under or over forecasting in order to achieve a particular incentive outcome. National Grid notes that its wider licence obligations ensure it is economic and efficient in its actions, which would include its actions in balancing the system. In order to balance the system economically and efficiently, the most accurate demand forecast possible is required. Therefore the wider licence obligations already cover the objective that this additional mechanism is trying to achieve. We do not support the introduction of this mechanism as it does not fit with Ofgem's objective under its better regulation work programme of ensuring the burden of regulation is reduced whilst ensuring consumers continue to remain protected.

Chapter 5: SO-TO Mechanism

Q1. Do you agree with our proposal to introduce a mechanism for the SO-TO to exchange funds? Please explain your answer.

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 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.

Q2. Do you agree with our proposal to introduce a pilot SO-TO incentive? Do you agree with the structure proposed? Is there anything missing or that should be removed? Please explain your answer.

We agree with the proposal to introduce a pilot incentive, with the opportunity to extend its parameters and use from 2018 onwards. The structure appears practical and workable, with the following modifications:

- Language should be changed to not solely focus on 'outages', but encompass any type of activity which could reduce overall system costs, eg. refer to 'projects/investments/works' in place of 'outages'.
- Regarding non/late-delivery of projects, our preference is that the TO would be paid pro-rata if it does not deliver the works to schedule.
- Regarding clarity on who can propose changes: any party who believes they have identified a way of reducing overall system cost should be able to propose that change. However, as discussed during working groups, it is envisaged that regular interaction between the SO and TOs, via the NAP and other collaborations, will provide opportunities to discuss propositions and agree how/when to proceed further.
- Regarding the fund size of £1.4mn per annum: we propose a similar mechanism to that already existing in STCP 11.3/Special Licence Condition 4C.31 whereby NGET could continue to spend on projects after the £1.4mn is exhausted and claim the additional funding via an outage cost adjusting event request.
- The requirement for the final report to be submitted by 1st May is unrealistic given the requirement to consult on the report and also have it validated by a third party. A more realistic date is 1st July. However, given we do not have sight at this point of billing terms/timescales etc. to be agreed with the TOs, we need to be cognisant that data availability will influence the time by which the report can be delivered.

In addition, we would like to again highlight that the mechanism would be simpler to implement from the System Operator's perspective if the costs agreed with the TOs were fixed in advance, as opposed to estimates with actual costs then invoiced. However, if this would prevent the TOs from engaging with the scheme we will work with this, monitoring any variance between cost estimates and actuals, as significant variance which increased costs would impact confidence in the scheme.

Q3. Do you agree with our proposal to introduce a requirement for a quarterly report? Is there anything missing or that should be removed? Please explain your answer.

Quarterly reporting could be an onerous burden given this is a pilot scheme; six-monthly is more appropriate.

We also believe the requirement for the final report to be submitted by 1st May is unrealistic given the requirement to consult on the report and also have it validated by a third party. A more realistic date is 1st July, dependent on data availability.

We would like further clarification:

- That the within-year reporting does not need to include rejected projects if the proposed investment was < £25k.
- That the yearly report, and the incentive scheme itself, applies to all investments undertaken regardless of the size of the individual costs, but that reporting on rejected investments is only required where proposed costs > £25k.
- If reporting can be confidential if the party providing the service to NG requests commercial confidentiality (or if public reporting can accommodate redaction for this purpose).

Chapter 6: Transparency, Model Development and Innovation

Q1. Do you agree that the proposed changes described in Chapter 2 will enhance transparency? Please explain your answer.
Although we agree the proposals would increase transparency, they currently include significant changes to the role of the SO over and above what we are doing today.
The Future Role of the SO consultation examines what an enhanced SO role could look like in the future, which would be a central actor in helping both Government and Ofgem in delivering a smart energy world. This enhanced SO role includes many of the proposed new balancing principles which Ofgem is suggesting to include in our licence conditions (e.g. taking account of whole system). System operation will be significantly more complex in a future world and the changes to the SO role required to meet this challenge should be considered in the round as part of the future of SO negotiations and the review of SO regulatory framework

Q2. Do you agree with our proposal to not introduce a financial incentive on transparency? Please explain your answer.
We do not agree that a transparency incentive should not be introduced at this stage.
The accelerated decarbonisation of the energy system, with increasing amounts of distributed, renewable generation has required us to transform our activities further, and at a faster pace, than envisioned in RIIO-T1. Moving to a smart energy world will introduce additional complexity to system operation with increasing numbers of smaller parties providing us with ancillary services as well as relying on ancillary services revenue streams.

A new way of working needs to be established between the SO and its wide range of providers, taking account of the complex contracting strategies which many new technologies and market models rely on in order to realise their business cases. Many of the required changes represent a significant step change to the way the SO operates today and needs substantial investment in people, processes and technology to ensure that investment and operational signals are strengthened and greater transparency established. A transparency incentive should be established during this interim incentive period to provide a means of measuring how effective we are in transforming our processes in order to perform this role, and to provide a modest incentive based on the level of effectiveness achieved.

Q3. Do you agree with our proposal to retain the MDLC? If not, please explain your answer.
We agree that the MDLC should be retained. BSIS for 2017-18 is reliant on enhanced models for target setting and the MDLC supports the operation of these models and the incentive scheme.

Q4. Do you agree that we should amend the MDLC to require NGET to get third party scrutiny on areas where the model could be improved? Please explain your answer.
Given the extent of the additional new governance around BSIS 2017-18 we do not agree that there is a need to amend the MDLC to require us to get third party scrutiny to identify model improvements.
The new governance measures, including a pre-scheme independent audit of the models and enhanced scheme performance monitoring will inform us where attention is required.

Q5. Do you agree with our proposal to discontinue the System Operator Innovation Roll-Out mechanism? Please explain your answer.
Yes we support the discontinuance of the SOIRM. It makes most efficient use of SO/Ofgem resource to concentrate on the fundamental review set for Electricity SO Incentives from 2018 and deliver the 2017-18 Incentive scheme with its additional governance requirements to a high standard. This makes this additional IRM unlikely to be used in 2017-18.

APPENDIX 2 – STAKEHOLDER VIEWS ON DEMAND FORECASTING

Stakeholder Views on
Demand Forecasting.

APPENDIX 3: REVIEW OF MET OFFICE WEATHER FORECAST ACCURACY

Review of Met Office
Weather Forecast Ac

APPENDIX 4: DEMAND FORECASTING INCENTIVE – NATIONAL GRID PROPOSAL

It is proposed that the Ofgem model be followed, with a number of separate schemes, each with several components.

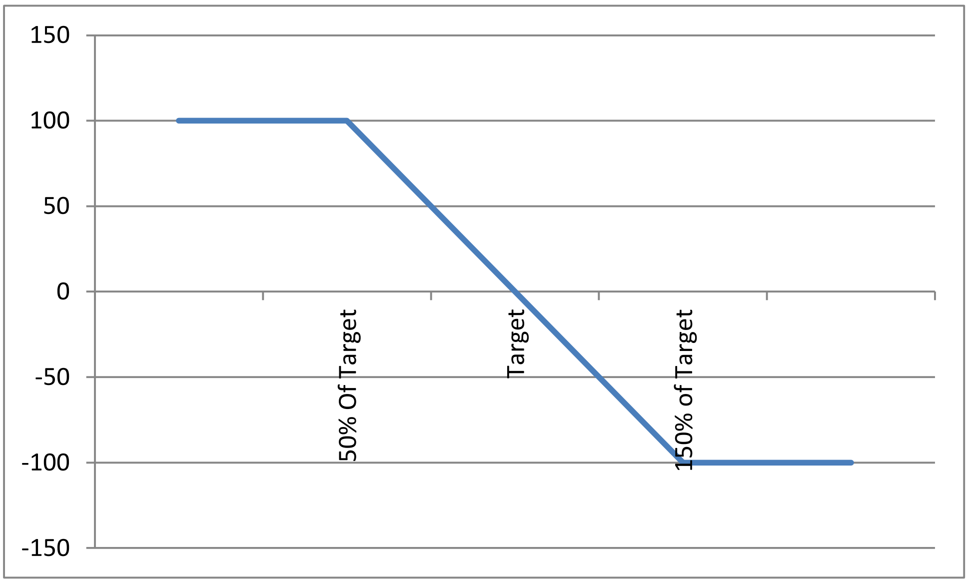
The number of cardinal points used to produce forecasts varies through the year, and can be a function of minor system issues requiring additional arbitrary points to be created to aid data transfers between systems. It is therefore proposed that incentives should be based on four values each day: the overnight trough; the morning / lunchtime peak; the afternoon trough; and the evening peak, collectively referred to as the daily turning points.

The overnight trough is defined as the minimum demand over a settlement period occurring between 00:00 and 06:30. The morning / lunchtime peak is the maximum demand over a settlement period between 07:00 and 13:00. The afternoon trough is the minimum demand over a settlement period between 13:30 and 16:00. The evening peak is defined as the maximum demand over a settlement period between 16:30 and 23:30.

Targets will be set for each of the four points for each time frame, as a daily absolute MW error, with different values in summer and winter. The incentive shall be weighted towards the more important points.

The proposal is for four time frames, within day, day ahead, two day ahead and seven day ahead. The accuracy of each forecast shall be assessed against the four points for the relevant time frame, but to reflect customer desire for a half hourly resolution forecast a full 7 day half hourly resolution forecast will be published each time any of the four incentivised forecasts is produced each day.

For each timeframe for each turning point there shall be a target absolute error in MW, and an incentive value per day. The targets and values shall be different in summer and winter. The incentive shall be linear, with a maximum reward for the day if the error is less than 50% of the target value, and a maximum penalty if the error is more than 150% of the target.



It is noted that the increasing use of demand side balancing tools has the potential for National Grid to be suspected of using such tools to move metered demand outturn towards the forecast value. In order to avoid the potential for such a situation, all demand forecasts will be for the demand prior to any balancing actions taken by National Grid. Where National Grid instructs demand side balancing actions, the volume of instructed actions shall be included in the outturn demand data published along with these forecasts, and the outturn values shall be corrected for these volumes before being used to calculate a demand forecast error. The forecasts shall allow for customer initiated actions such as Customer Demand Management or Triad Avoidance.

1. In Day Demand Forecast

A significant amount of customer feedback reflects the desire for an in day forecast produced by 0700 each day. This incentive shall be for the production of a Half Hourly forecast for the next 7 days by 0700 each day, focussed on within day accuracy. The target shall exclude the within day overnight trough as this will have occurred before the forecast is produced.

2. Day Ahead Forecast

A second forecast for 7 days ahead at half hourly resolution shall be produced by 0900 each day, focussed on Day Ahead, with an incentive on the accuracy of the forecast for all four turning points at Day Ahead

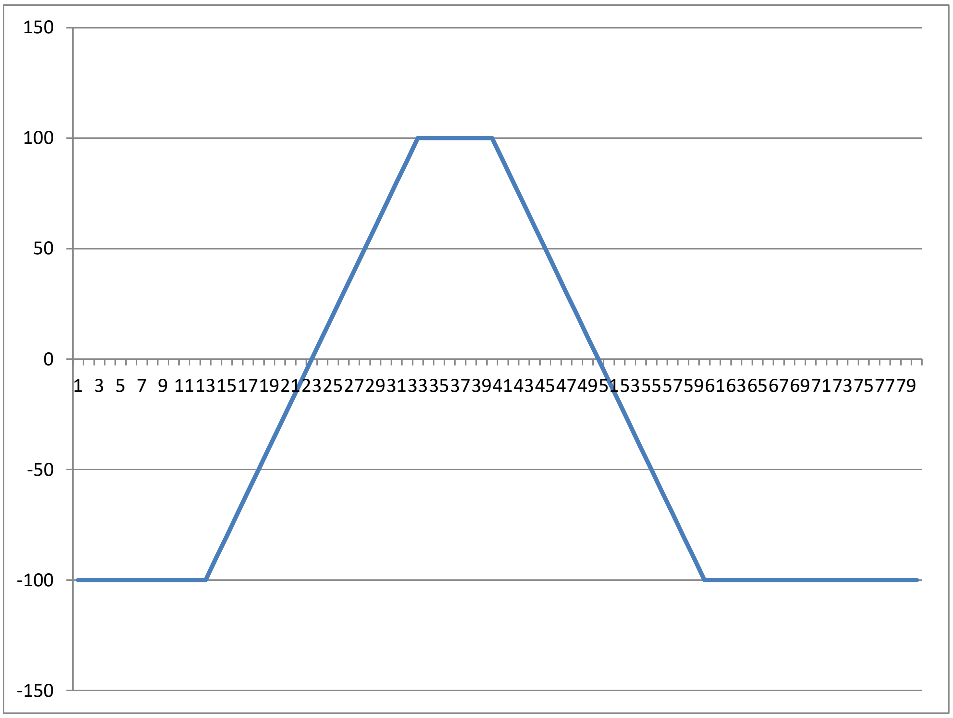
3. Two Day Ahead Forecast

A further forecast for 7 days ahead at half hourly resolution shall be produced by 1500 each day, focussed on Two Days Ahead, with an incentive on the accuracy of the forecast for all four turning points at Two Days Ahead.

4. Seven Day Ahead Forecast

A further forecast for 7 days ahead at half hourly resolution shall be produced by 1200 each day, focussed on seven days ahead. To reflect the significant weather uncertainties associated with this time horizon, this forecast shall take the form of a 90% confidence level, i.e. stating for example that the evening peak will be between 49,500 MW and 50,300 MW. The measure of accuracy of this forecast shall be that over the course of the year the demand outturns outside the 90% confidence level on 33 to 40 occasions. Maximum reward will be for this number of deviations. Less deviation shows that the confidence levels were set too wide, and so will attract a penalty, while more deviations shows the levels were too tight, and so again will attract a penalty.

Maximum penalty shall be incurred for less than 13 or more than 60 outturns outside the confidence level.



Proposed Targets and weightings for the schemes are summarised below:

Each scheme has a daily value which represents the maximum penalty/reward for that day. The scheme is capped by a scheme value for summer and winter for each time horizon

		Overnight Trough	Morning Peak	Afternoon Trough	Evening Peak	Scheme Value	Daily Value
Within Day	Summer Weighting		40%	40%	20%	£0.1m	£750
	Summer Target		800 MW	1000 MW	800 MW		
	Winter Weighting		25%	25%	50%	£0.15m	£1,000
	Winter Target		800 MW	800 MW	800 MW		
Day Ahead	Summer Weighting	30%	30%	30%	10%	£0.2m	£1,500
	Summer Target	800 MW	1000 MW	1200 MW	900 MW		
	Winter Weighting	10%	20%	20%	50%	£0.3m	£2,000
	Winter Target	800 MW	1000 MW	1000 MW	1200 MW		
2 Day Ahead	Summer Weighting	30%	30%	30%	10%	£0.2m	£1,500
	Summer Target	1000 MW	1200 MW	1400 MW	1000 MW		
	Winter Weighting	10%	20%	20%	50%	£0.3m	£2,000
	Winter Target	1000 MW	1100 MW	1100 MW	1300 MW		
7 Day Ahead	Weighting	25%	25%	25%	25%	£0.25m	

To illustrate the proposal, a winter within day forecast for afternoon trough has a target of 1000 MW. 50% of this value is 500 MW, so the maximum reward is at 500 MW and the maximum penalty at 1500 MW error. An error of 800 MW = 200 / 500 below target = 40% below target. The weighting of the afternoon trough is 25% of the daily value of £1000 = £250, and so this is the maximum reward/penalty for this turning point. The reward of 40% of this value is £100.

A Day Ahead winter evening peak has a target of 1200 MW, and so an error of 1500 MW is 300 MW above the target, or 50% of the maximum 600 MW error. The weighting of 50% of the daily value of £2000 is £1000, and so an error of 1800 MW would result in a penalty of £1000, while an error of 1500 MW, or 50% of maximum error attracts a penalty of half of this amount, £500.

For the 7 day ahead scheme, if over the year we were outside the forecast range on 55 occasions for the evening peak, then this is 15 over the upper deadband limit of 40, and is at the mid point of the loss range (50 to 60), and so would attract a penalty of 50% of the maximum. The weighting for the evening peak is 25% of the £250,000 scheme = £62,500, and so a 50% penalty would equate to a loss of £31,250.

The timings of the various incentives are summarised below. A full 7 day ahead half hour resolution forecast will be published at each of the four timestamps each day, but the incentive will be based on the turning point forecasts for each time horizon, also defined below. These turning point forecasts will be published explicitly in a separate table.

4 Periods Definitions		
P1 - Overnight Minimum	00:00	06:00
P2 - Daytime/Morning Peak	06:30	13:00
P3- Daytime Minimum	13:30	16:00
P4 - Evening/Darkest Peak	16:30	23:30

		Day 0				Day + 1				Day + 2				Day + 7			
In Day	700	P1	P2	P3	P4	P1	P2	P3	P4	P1	P2	P3	P4	P1	P2	P3	P4
D+1	09:00	P1	P2	P3	P4	**P1**	**P2**	**P3**	**P4**	P1	P2	P3	P4	P1	P2	P3	P4
D+7	12:00	P1	P2	P3	P4	P1	P2	P3	P4	P1	P2	P3	P4	**P1**	**P2**	**P3**	**P4**
D+2	15:00	P1	P2	P3	P4	P1	P2	P3	P4	**P1**	**P2**	**P3**	**P4**	P1	P2	P3	P4

In order to meet our customers requests for transparency, the half hour forecasts will include forecasts for embedded wind, embedded PV and Customer Demand Management

Wind Forecasting Incentive
To date, the wind power forecasting incentive has been based on BMU wind output. National Grid produces forecasts for embedded wind as part of its calculation of national demand forecasts, but data on the output of these embedded wind generators has not been available.

National Grid has been working with ElectraLink in order to source aggregated settlement metering for embedded generation. This includes settlement metering for all embedded wind generation of 30 kW and above.

An incentive is proposed that National Grid publish a forecast of total wind generation, broken down into Directly Connected and Embedded components. The incentive will be based on a forecast of total wind generation, measured as the sum of BMU settlement metering from Elexon and aggregated embedded generation settlement metering from ElectraLink.

A similar form of incentive is proposed, with components for the same four time horizons, published at the same times.

National Grid will publish hourly resolution forecasts for Directly Connected and Embedded wind generation (weather forecasts are only available at hourly resolution). These forecasts shall be used to calculate a total wind energy forecast for the day, in MWh.

It is recognised that it is harder to forecast embedded wind generation. While aggregated settlement metering data is available, site specific outputs and wind speed measurements are not available, and so site specific wind power curves cannot be created; only generic power curves can be used. This introduces a greater error, and so the target values are greater than those that would be set for purely directly connected wind.

In their consultation, Ofgem expressed dissatisfaction with the current methodology of discounting all wind generators in receipt of a BOA during a settlement period, It is therefore proposed that National Grid will continue to forecast the wind generation that would have occurred had National Grid not taken any balancing actions. Further, they will publish the estimated volume of actions, calculated as the difference between the forecast wind output for each wind generator in receipt of a BOA or other balancing action for that settlement period and the metered value (which would usually be the level instructed in the BOA). National Grid will publish and correct the wind outturn values prior to calculating the forecast error.

The current scheme is sub-optimal in that the targets are based on a percentage of capacity. This means that at low wind speeds the targets are over generous as they can represent a large percentage of the total wind generation at the time. Similarly they can be very tight at high wind speeds. The net effect is that the performance against the scheme is determined by how windy a year it is.

In order to avoid this issue, the proposed scheme will have a target for each time horizon as a percentage of the total outturn energy generated in the day (including corrections for balancing actions). In order to avoid the theoretical problem of a totally calm day giving a target error of 0, a minimum generation shall be set at 12,000 MWh per day. This equates to an average of 500 MW of wind generation across the day

As the scheme is based on a percentage error, there is no need for separate summer and winter targets. Each scheme will be linear, with a central target and upper and lower bands

The overall scheme of £0.5m shall be made up as follows:

	Target	Lower Limit	Upper Limit	Scheme Value	Daily Value
Within Day	10%	5%	15%	£75,000	£300
Day Ahead	12%	7%	17%	£175,000	£750
2 Day Ahead	15%	10%	20%	£175,000	£750
7 Day Ahead				£75,000	

For example, at day ahead, in the unlikely event of a continuous 4,000 MW of total wind generation for the day, with a forecast of a continuous 4,500 MW, the error is 500/4000 = 12.5% . This is 0.5% above target, or 1/10 of the 5% incentive range. This then equates to a loss of 1/10 of the daily value of £750, or £75.

APPENDIX 5: NATIONAL GRID COMMENTARY ON OFGEM DEMAND FORECASTING INCENTIVE

National Grid
Commentary on Ofge

APPENDIX 6: SMITH INSTITUTE REVIEW OF DEMAND FORECASTING PROPOSALS

SMITHS INSTITUTE -
DEMAND FORECASTI