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Dear Ian

System Operator incentive schemes from 2013

EDF Energy is one of the UK's largest energy companies with activities throughout the energy chain. Our interests include nuclear, renewables, coal and gas-fired electricity generation, combined heat and power, and energy supply to end users. We have over five million electricity and gas customer accounts in the UK, including both residential and business users.

We welcome the opportunity to respond to this consultation and provide our views on the SO Incentives post 2013. The key points of our response are:

- Any incentive scheme should be transparent and replicable. This will allow interested parties to use the incentive parameters to forecast costs and also help to identify any improvements.
- There is a clear value from introducing longer term SO incentive schemes than those that have been used historically, as this will allow the SO to take investment decisions with a longer pay back period than would otherwise have been the case. When combined with a SO-TO incentive scheme, this should help to ensure that overall costs to consumers are minimised.
- The movement from a 1 year to an 8 year incentive is a large step to take, even with a mid-term review. Given the size of this change, there may be a value in setting the 8 year incentive scheme with a review every 2 years to ensure that the incentives are operating as intended.
- The roll out of smart meters and the development of a smart grid could provide significant opportunities in the operation of the gas and electricity systems. Although the opportunity for savings is likely to be greater for the electricity SO, it would appear appropriate that these opportunities are incentivised in both gas and electricity to ensure that they are captured.
- There is value to bundling the incentive schemes where appropriate to ensure that the SO is incentivised to take the most efficient action. This is especially the case for the gas SO incentives that have historically been set independently; however, bundling should only occur where there are clear interactions.

Our detailed responses are set out in the attachment to this letter. Should you wish to discuss any of the issues raised in our response or have any queries please contact my colleague Stefan Leedham on 0203 126 2312, or myself.

Yours sincerely,

Rob Rome
Head of transmission & trading Arrangements

Attachment

System Operator incentive schemes from 2013

EDF Energy's response to your questions

CHAPTER: One
Question 1: Do you consider that the general principles we have used are appropriate? Are there any other principles that we need to consider?

The principles proposed by Ofgem appear appropriate and consistent with those applied to the RIIO-T1 mechanisms. In particular, we support the recognition and proposals to incentivise the interactions between SO and TO activities to ensure that the costs to consumers are minimised. Actions and decisions taken by the TOs clearly have a direct impact on SO costs, such as constraint resolution and losses. It would appear appropriate that these interactions are incentivised so that the lowest costs are delivered to consumers.

CHAPTER: Three
Question 2: Do you consider that we have identified all the relevant outputs for the electricity SO? Should we consider any other outputs?

The list of outputs identified is extensive and covers most of the relevant electricity SO outputs; however, it is not clear whether some of the suggested outputs are attributable for the SO or TO activities. In particular, although National Grid (NG) has responsibility for providing the Seven Year Statement (SYS) and management of the CUSC and Grid Code, there are also clear interactions with the long term planning and management of the TO Systems. It might therefore be prudent to ensure that the SO-TO incentives are appropriate to assist with any SO output in this respect.

It is notable that additional interactions and opportunities for SO activities that might result from the roll out of smart meters and the development of smart grids are absent from the list of outputs. Given the potential benefits that could be derived from these, it would be appropriate to incentivise the SO to capture these opportunities when they arise.

Question 3: Do you consider that we have identified all the relevant outputs for the gas SO? Should we consider any other outputs?

As with electricity, the list of outputs identified is extensive and most of the relevant outputs have been identified; however, as noted above, smart metering opportunities might also be included. Although it appears likely that the opportunities to the gas SO role from smart metering are limited compared to those suggested for electricity, some

opportunities will be present, such as improvements to demand forecasting, and these should be incentivised to ensure that they are captured.

In addition, there would appear to be some value in incentivising the demand forecast outputs that NG produces and not to limit these to total system forecasts. Significant advances have been made in the day ahead national forecasts since they were introduced; however, there is also value in incentivising the demand forecast for the NDM sectors and the energy allocation process. NG should be encouraged to participate in meteorological studies on the impact that climate change may have on forecasting.

For example, there were issues with the NDM forecasting and allocation processes in April and May 2011 that led to large movements in the D to D+5 NDM energy allocation and imbalance positions. This may have had an impact on shippers' credit positions; should this have occurred in winter, the impact would have been even more significant. Shippers have been concerned with NDM forecasting accuracy and energy allocation for a significant period of time and so it would appear appropriate that this is now subject to an output measure.

In the context of climate change, it might be timely to fully incorporate some aspect of this into NG's SO role. There may therefore be value in a single demand forecasting output, with D-1 total system forecast, NDM forecasting and allocation, and meteorological developments all being part of this high level output.

Question 4: Please provide your views on which of the outputs of both the electricity and gas SOs should be incentivised.

The electricity outputs identified by Ofgem in chapter 3 of their consultation for incentivisation appear appropriate. However, we believe that all incentives should be transparent and replicable by industry. This will support cost forecasting and provide assurance to industry that the incentives are operating as intended. We note that the electricity incentives implemented for 2011 are not fully replicable by industry. We do not believe that this is appropriate and have engaged fully with both National Grid and Ofgem to highlight our wish for greater transparency of the modelling approach.

For the gas SO incentives it is not appropriate to remove the incentive on NG to reduce Unaccounted for Gas (UAG). We note that NG accepted this incentive in 2009. UAG has a significant impact on the allocation of costs to Shippers, with identified meter errors in 2009/10 impacting on the allocation of £60-70m of gas. It would therefore appear appropriate that this output measure is incentivised. An example of the effectiveness of incentives can be found in the improvements observed in demand forecasting since the introduction of its incentive. The development of a UAG incentive with financial rewards and costs to NG could also deliver improvements.

Question 5: Do you agree that it may be more appropriate to place licence obligations (funded through the internal gas SO incentive scheme) with respect to UAG and /or Information Provision?

We recognise that responsibility for meters rests with the GDNs, who will also be subject to a reliability output. In line with the TO and SO regimes, there are interactions between the GDN and SO activities. NG as gas TSO has responsibility for the procurement of UAG volumes, and is also the contractual counterparty to the GDNs for enforcement of UNC Offtake Arrangements Document (OAD) and other contractual arrangements which stipulates meter requirements and standards. It would therefore appear appropriate that NG is incentivised to ensure that the contractual requirements for offtake meters and validations are adhered to. For example, the UNC requires validations to be undertaken every 12 months; if this were not to happen and resulted in a meter error lasting longer than necessary, we believe that NG should be exposed to these avoidable costs.

A financial incentive would also encourage NG to explore new ways of reducing UAG or focusing GDN attention in this area. For example the application of a scheduling charge to GDN Offtake Profile Notice (OPN) submissions may focus attention on their accuracy and would have resulted in the almost immediate identification of errors of 40%, rather than the 6 to 12 months that lapsed before the Aberdeen and Braishfield errors were identified. We note that Shippers are exposed to scheduling charges and coincidentally the number meter errors occurring for a significant volume and period of time are less. Therefore, the combination of a licence requirement along with the development of a financial incentive with risk and reward for NG appears appropriate.

Question 6: Is there a need for greater incentivisation of NGET and NGG with respect to customer satisfaction? If yes, what form should this incentivisation take?

There appears to be merit in developing an output measure to incentivise improved customer satisfaction with regards to the SO roles. As identified in the consultation, this will need to be developed so that there are no overlaps with the areas already incentivised under the RIIO-T1 mechanism, which we do not anticipate to be difficult to overcome. We suggest that a measure on collaborative working with industry participants to develop mandatory and commercial balancing services for electricity would be valid.

CHAPTER: Four
Question 7: Do you consider that the reasons we have proposed for bundling are reasonable? If not, please provide your views as to why.

The proposals to introduce a degree of bundling appear reasonable. In particular it appears appropriate for NG to be incentivised to reduce overall costs for consumers. At the same time, we recognise that there are issues with full bundling as not all incentives are linked, and so full bundling results in specific outputs and incentives losing focus.

Question 8: Do you consider that the options for bundling are reasonable? Are there any additional options that we should be considering?

The options for bundling identified by Ofgem are quite extensive and seem to cover all of the identifiable options.

Question 9: Do you consider that, based on the current outputs that are incentivised, continuing to bundle the electricity SO scheme is appropriate?

Bundling the electricity SO incentive scheme appears to be appropriate; provided that there is transparency around the individual schemes. In particular, it would be beneficial if NG's modelling and assumptions were fully transparent so that these can be replicated by industry to aid forecasting processes. It would also be beneficial were NG to provide a detailed view on performance against each of the individual measures so that the industry has transparency around where costs and benefits are being incurred.

Question 10: If you consider that the electricity SO should be incentivised on additional outputs, should these be part of the same bundled scheme? If not, how should the incentives be packaged?

It is not clear that incentivising NG to realise the benefits from smart meters and grids would fall into the traditional electricity SO pot, and so there may be a value in having a separate incentive in this area.

Question 11: Do you consider that there is merit in increasing the number of gas outputs incentivised through a single scheme?

The current unbundling of gas SO incentives can create some perverse trade-offs, especially when the cap or collar has been hit on a specific incentive. However, there does not appear to be sufficient interaction between the incentives to warrant full bundling. It would therefore appear appropriate to align the sharing factors of all the incentives and bundle those where there are synergies or trade offs.

Question 12: How do you consider the outputs of the gas SO should be incentivised?

Symmetrical incentives providing rewards for over performance and costs for under performance, with common sharing factors and appropriate caps and collars would appear to present the most effective solution. An SO gas cost would appear appropriate for all of the incentives other than the demand forecasting proposal which should be incentivised based on accuracy of demand forecasts.

Question 13: How do you consider that the incentives on the gas SO should be packaged?

The proposals in 4.31 provide some interesting options. The industry has historically expressed concerns with the separation of the shrinkage and environmental incentives as NG could potentially be rewarded twice under these separate incentives. It would therefore appear appropriate that these incentives are bundled together. There may also be a value in bundling the capacity buyback and residual balancing incentive as there are clear interactions in gas when a constraint occurs; however, consideration will need to be given as to how this will operate in practice given the infrequent occurrences of constraints in gas.

As previously noted we are supportive of a bundled demand forecasting incentive; however, the elements of this incentive should comprise of D-1 demand forecast accuracy, NDM D demand forecast accuracy, NDM D energy allocation accuracy, and incentivising the development of demand forecasts that take account of climate change developments – potentially looking at the accuracy of demand forecasts over a multi-year period.

CHAPTER: Five
Question 14: Have all the benefits associated with moving to longer term incentive schemes been captured? Should any additional issues be considered?

Ofgem appears to have captured the majority of benefits from moving to a longer SO incentive scheme. The most significant of these will be to ensure that the SO can take investment decisions with a longer payback period than would historically be the case with a 1-2 year incentive scheme. However, the move from single year to schemes to an 8 year scheme even with a mid term review would appear to be a large step. Given the volatility faced by the SO, our initial preference would be to set an 8 year scheme with a review of the parameters every 2 years to ensure that the incentives are operating as intended.

Question 15: Can longer term SO schemes be implemented through the different approaches discussed, year by year incentives and multi year block incentives? What do you consider are the relative merits (or otherwise) of each approach?

As identified by Ofgem the main benefit from a year by year incentive is that the exposure of the SO is limited on an annual basis; while a multi year block incentive allows under performance in one year to be offset against over performance the next. However, the assumption behind both incentives is that an appropriate structure and incentive can be set for a multi year period – either for individual years or for a block of years. There is a risk when setting a multi year incentive that it is too harsh, or too lenient on the SO; resulting in either excessive losses or profits. As recognised within the consultation the volatility faced by the SO is greater than that faced by the TO and so there is a greater risk of setting an incorrect incentive. There will therefore be a need to ensure that these

uncertainties and risks are covered. This would suggest that a year on year incentive scheme is more appropriate as it will limit the exposure of the SO and consumers.

Question 16: Is our proposed treatment of uncertainty and risk associated with longer term schemes reasonable? If not, please explain how this can be improved.

The use of an uncertainty mechanism, similar to the RIIO-T1 arrangements appears appropriate. However, this mechanism should be used to cover instances when the SO's costs are lower than expected as well as when they are higher than expected. In our historical experience, NG has shown a tendency to seek protection against increasing costs, but a reluctance for Ofgem to instigate a review when costs have decreased significantly. It would therefore appear appropriate to develop an uncertainty mechanism that covers both scenarios that also provides sufficient flexibility to cover unexpected events.

CHAPTER: Six
Question 17: Do you consider that it would be of overall benefit to consumers to better align the incentives of the SOs and the TOs?

As previously noted there is a value in aligning the SO and TO incentives so that these can be traded off to provide the lowest cost to consumers. The clearest example of this is instances when TO investment reduces SO costs to the overall benefit of consumers. Historically due to the different length of the incentive scheme and sharing factors, this trade off would not have occurred even when the SO and TO had a common ownership.

Question 18: Please provide your views on the extent to which better alignment can be achieved through the alignment of the incentive schemes under the same and separate ownership.

The alignment of incentives and payment mechanisms appears to be a sensible solution to drive TO and SO interactions that will help to reduce overall costs to consumers.

Question 19: Please provide your views on the economic incentives to drive SO-TO interactions ("payment mechanism"). In what areas could this principle be usefully applied?

This principle could be applied most clearly to areas where the SO and TO are under separate ownership that could benefit from more co-ordinated approaches, such as outage management.

It is clear from Ofgem's example that there are valuable potential benefits to be realised in providing an incentive mechanism to drive SO-TO interactions in the management of constraint costs. Constraints can be both caused and exacerbated by the need for a TO to take outages on the network and we anticipate that the volume of transmission system

development within the coming price control period will be significant. We therefore agree that the appropriate incentives to manage this interaction can be of benefit to consumers.

EDF Energy
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