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Dear Andrew

Response to System Operator Incentive Schemes from 2013 Consultation

We welcome the opportunity to respond to Ofgem's consultation on system operator incentive schemes from 2013.

National Grid owns and operates the high voltage electricity transmission system in England and Wales and, as National Electricity Transmission System Operator (NETSO), operates the Scottish high voltage transmission system. We also own and operate the gas transmission system throughout Great Britain and, through our low pressure gas distribution business, distribute gas in the heart of England to approximately eleven million businesses, schools and homes. This response is on behalf of our UK gas and electricity transmission businesses.

This response is in two parts: this opening section provides general comments on the issues raised in and by the consultation, which is followed by an Appendix which considers some of the specific questions that are raised in the consultation. This response can be treated as non-confidential.

Role of Incentives

We strongly believe that system operator incentives play an important role in driving innovation and positive change; and that it is appropriate to ensure that our interests are aligned with those of our customers and other incentivised parties to drive behaviour that best serves customer interests. Targeted incentives on parties who are best placed to manage risks associated with activities should promote the efficient delivery of those activities.

For the most efficient outcomes for a particular output, the incentive should be structured to provide consistently strong incentives to trade off different options, such as between investment and operational solutions.

Duration of Incentives

We support work to move towards longer term incentive schemes, as these have the potential to encourage longer-term activities to be undertaken to drive efficiencies, when combined with suitable opportunity for pay-back. However, as incentive schemes become longer, the risk that volatility could drive windfall gains and losses increases. We consider this risk is best achieved by the use of uncertainty mechanisms such as specific re-openers, ex-ante or ex-post adjustment mechanisms, in conjunction with appropriate profit caps/loss floors, to ensure the incentive is focused on cost drivers that can be controlled or influenced by the incentivised party.

Bundling of Incentives

We agree that bundling of incentives can add value where there are material interactions between various different performance measures. This has been demonstrated over a number of years in relation to the electricity system operator incentive, where one action can manage a number of system operation needs. Further, financial bundling (the bundling of caps/floors of individual incentives) could increase the incentive to continue to pursue efficiencies in areas where performance would otherwise have resulted in a cap or collar being reached.

However, the extent to which bundling can be applied needs to be carefully considered such that resulting cost trade-offs can be made in a transparent manner. Where interactions are weak or complex, specific performance measures might be more relevant, since the removal of complexity and separation of performance will aid understanding, targeting of effort and drive improvements in performance.

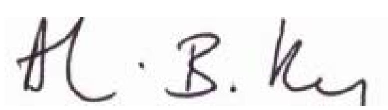
SO-TO Incentive Alignment

The roles of the System Operators (SOs) and Transmission Owners (TOs) are intrinsically linked such that the performance of SOs is highly dependent on the decisions made by relevant TOs at the time of investment in assets. As a combined SO and TO, we are able to consider the tensions between SO and TO activities on a co-ordinated basis to drive the most efficient and economic operation of the network; we are also able to pursue similar efficiencies with other TOs, such as is provided for under the electricity SO-TO Code (STC). We therefore support measures to further develop the alignment between SO and TO priorities, regardless of ownership.

We welcome Ofgem’s suggestion for an industry workshop and consider it important to have the opportunity to discuss the range of issues highlighted in the consultation and the opportunity to discuss within the industry.

We would be happy to discuss and expand on any of the points made in this response. If you would like to discuss this response please contact Juliana Urdal about any of the gas SO aspects (Juliana.Urdal@uk.ngrid.com or 01926 656195) or Ian Pashley for any of the electricity SO aspects (Ian.Pashley@uk.ngrid.com or 01926 653446).

Yours sincerely



Alison Kay

Appendix: Answers to specific questions

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

As set out in the covering letter to this response, we consider that the general principles used are appropriate. Further specific comments can be found in the answers to the relevant questions.

Other principles to consider
National Grid considers that there are increasing interactions between gas and electricity system operation and that there may be value in consulting on the potential benefits of formal interactions between the gas and electricity system operation roles to drive the most efficient outcomes for the energy industry as a whole. For example, as decarbonisation through wind generation increases, the use of gas generation on days when wind generation is variable is forecast to place increasing demands on the gas network to provide flexibility. It will be important to ensure that processes, commercial tools and arrangements, networks, IS systems and relationships are developed to support this change.

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

The electricity SO outputs identified in the consultation are a mixture of high level and more detailed outputs; and the we consider that the main outputs with particular relevance or materiality are identified within the consultation document.

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

The gas SO outputs identified in the consultation are a mixture of high level and more detailed outputs. Whilst the main outputs with particular relevance or materiality are identified within the consultation document, we present additional outputs below.

Our view is that the most important output of the gas SO role is to operate the gas National Transmission System (NTS) safely. This output includes protecting the safety, health and welfare of its employees and our responsibility to conduct our operations in ways that are most protective of public safety (as set out in the electricity SO outputs) as well as adherence to other safety considerations including statutory obligations[1] that cover for example:

- Ensuring that pressure within the NTS and made available to offtaking parties is maintained within safe limits;
- Ensuring that the quality of gas allowed to enter and made available at the exit of the NTS is in accordance with our statutory obligations;
- Operation of the compressor fleet within environmental, site specific, permits; and
- Ensure that capabilities and processes are in place to effectively manage a Network Gas Supply Emergency.

Additionally, we consider that providing network flexibility in line with contractual obligations (and beyond when system conditions allow) should be included as an output measure. The difficulty with this latter output is how to measure it; however it would be of potential customer benefit to consider an appropriate framework for its performance measurement.

[1] Statutory Obligations include Gas Safety (Management) Regulations 1996, Pipeline Safety Regulations 1996, Pressure Systems Safety Regulations 2000, Environmental Permitting Regulations and the Pollution Prevention Control (PPC) Regulations.

In considering the outputs set out by Ofgem in its consultation document, we feel that it would be more appropriate to have the management (not just monitoring or calculation) of SO activities as the output, such as for Shrinkage where zonal gas quality is managed to ensure consumers are being fairly billed for the energy they consume.

For the provision of system access, generally referred to as "capacity", we consider that the output should be making NTS entry and exit capacity available in line with obligations and contractual rights plus providing incremental capacity when users require it and system risk is manageable.

Other outputs identified for the gas SO are:

- Providing contracted pressures at inputs and offtakes;
- Management of the network in line with entry and exit obligations and beyond when system conditions allow;
- Maintaining system access for customers whilst still completing necessary system maintenance and construction activities; and
- Providing data on behalf of the GB gas market, and not just in relation to the NTS. This role also includes the management of any system "Difficult Day" notification processes.

The role of the System Operator is likely to evolve over the RIIO-T1 period in order to facilitate changing industry and governmental priorities, whether due to changing customer requirements (such as for gas generators) or policy changes as have been seen in the last few years with greater emphasis on interconnection and environmental policy. Changes in expectations for the services that the SO delivers may change the priorities between outputs and will almost certainly introduce the need to consider new outputs during the RIIO period.

It would also be useful to consider the RIIO-T1 outputs and output categories in conjunction with these SO outputs to best allow the alignment and potential trade-offs to be identified.

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

Our views on the additional SO outputs that Ofgem consider could be incentivised follow. As the industry evolves, it may be appropriate to reassess which outputs are appropriate for incentivisation (an example of a trigger for such a revisit could be when industry and governmental priorities change).

<u>Electricity</u>
We are already incentivised to minimise energy not supplied via our transmission network reliability incentive scheme[2]. This scheme incentivises us to minimise the time between a loss of supply event and either (a) the point at which we directly restore supplies to customers (without intervention by the customer) or (b) the point at which we inform the customer that supplies are ready to be taken, so that they can undertake their own processes to restore supplies.

We assume, for the proposed incentive in respect of energy not supplied, that it is focused on minimising the time between:

1. The point at which the TO indicates to the SO that assets are ready to make supplies available; and
2. The point at which the SO informs the customer that supplies are available to be taken.

[2] As set out in Part 1 of Special Condition D5 of our electricity transmission licence

Generally, it will only be under specific, rare circumstances that there would be a delay between the TO confirming assets were ready to make supplies available and the SO informing the customer. These would tend to be where additional operational or safety considerations were required, such as the need to complete equipment inspections or manage fault levels during switching (which may involve the running of system security studies to determine the best approach).

Beyond the point at which we have informed the customer that supplies are ready to be taken, we have no real ability to influence the customer's subsequent actions to restore supplies.

We think it is important to ensure that we are not incentivised to put safety at risk; or to be penalised where we have made reasonable attempts to inform a customer that supplies are available but have been unable to make contact with them.

Given the scale of the change anticipated over the coming years, it may be appropriate to develop incentives on other activities, such as demand forecasting, wind forecasting or other information provision. Gas SO incentives for demand forecasting and information provision have been demonstrated to deliver value to the industry. While much information is already made available to the industry, potentially there is value in the provision of this information for different timescales and at varying lead-times, recognising the impact on potential for accuracy for each. Some form of 'value added' test could be used to determine if incentivisation on the additional information is in the best interests of consumers.

Additionally it would be appropriate to consider other areas where the industry might value significant additional data or supporting information, for example around forecasts of Balancing Services Use of System (BSUoS) charges. We could be incentivised around the timely production of such forecasts/information. The timescales for such information provision would need careful consideration as the design of the two-year SO incentive scheme for 2011-13 recognises that there are significant cost drivers which National Grid does not currently forecast.

<u>Gas</u>
We consider that the SO services and functions that are currently incentivised are activities where incentives can continue to provide value for customers and consumers. To ensure that the incentives are fit for purpose for the RIIO-T1 period, we feel that it would be appropriate to consider the value, objectives and form of these incentives.

In addition to the existing incentivised outputs, as set out in the consultation, we believe that an incentive relating to the management of exit capacity constraints should be explicitly identified within the consultation. With full implementation of exit reform due to be implemented in October 2012, a scheme should be put in place which aligns the interests of all parties involved.

It should be noted that during the process of initialisation of the enduring exit arrangements, we released incremental exit capacity on the NTS and did not seek any additional funding to support this. We noted[3] that this would be likely to result in increased levels of risk above the TPCR4 settlement level and suggested that there should be "an agreement in principle to revisit this issue as part of the next PCR and to provide appropriate funding to manage the increased risks".

[3] Presentation provided to the 7th May 2009 Uniform Network Code (UNC) Transmission Workstream.

Within its decision letter which enacted the corresponding changes to the exit capacity baselines, Ofgem acknowledged our request and stated that, in principle, they agreed that this should be considered as part of the next price control.

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?

Unaccounted for Gas (UAG)

We are currently incentivised to minimise the absolute volume of UAG. UAG is an indicator of misallocation of costs between industry parties. The primary cause of this misallocation is believed, by many in the industry, to be the inherent measurement tolerances[4] associated with entry and exit measurement equipment. Measurement errors are also a factor, which can be as a result of many different issues. When corrected for known measurement issues and errors, UAG is estimated to be less than 0.5% of overall system throughput.

Whilst we have a meter assurance role, the measurement assets connected directly to the NTS are predominately owned by either Distribution Network Owners, Terminal Operators, Storage Operators, Interconnector Operators and/or large industrial end consumers. Any success in improving UAG is therefore reliant on mutual working and collaboration with these stakeholders who own, and are responsible for, the maintenance, repair and operation of this equipment, but who would not necessarily have the same incentive as ourselves as SO.

We recognise and acknowledge industry concerns regarding the prevailing levels of UAG. As part of the development of 2012/13 SO incentives and in order to inform the longer term debate on this issue, we are asking stakeholders for their views, through our Initial Consultation[5], on which party (or parties) should have a central role in the minimisation of UAG volumes; whether that role should be ours; and whether this should be in the form of incentivisation or a funded obligation. In developing the regime in this area, we consider that any incentive or licence obligation must be proportionate to the level of control that we have in this area.

Information Provision

We currently provide information to the industry through our website. We consider that there is a continuing role for providing useful information to the industry, such as is currently incentivised through the Gas SO data publication incentive. The consultation suggests ceasing to incentivise information publication; instead inserting requirements within NTS licence obligations. We consider that this would only be appropriate if such an obligation were on a reasonable endeavours basis and any associated operating and capital expenditure, required to deliver a clearly defined data set and level of service effectively, is included within baseline funding.

Incentive on NGG as gas SO for maintenance scheduling: We would welcome views on the materiality of this issue and how any incentive could be structured.

Maintenance is an essential part of our role in order to keep the network safe, fit for purpose and operated in an efficient and economic manner. This aligns with our obligations as set out

[4] The permitted tolerance for fiscal metering equipment connected to the NTS is ± 1%.
[5] National Grid Gas (NTS) System Operator Incentives for April 2012 Initial Consultation is available from our website at http://www.nationalgrid.com/uk/Gas/soincentives/docs.

in various regulations[6] and our licence. The materiality of maintenance scheduling to ourselves as SO is most significant in meeting our statutory obligations, with consideration given to the costs of providing maintenance in a way that considers our impacts on customers. Any potential incentive would need to recognise the importance of maintenance activities and should be considered alongside additional and aligned obligations on all parties to ensure the current safety and reliability of service is maintained for the end consumer.

In working with our customers to plan the maintenance programme, we request outage programmes from relevant and impacted industry parties to facilitate alignment of outages where feasible and to reduce the potential impact of carrying out the work required.

For exit related planned maintenance, there is a process set out in the Uniform Network Code (UNC) that enables us to inform industry parties of intended Maintenance Days. These are notified well in advance of the work. This provides industry parties with an opportunity to discuss the timing and impact of the outage and for us to respond to any industry requests for further information. Any amendments to the maintenance plan may be at our request (32%[7]) or shippers/consumers (68%). We seek to accommodate shipper/consumer requests where possible. In 2010, we were able to accommodate 63% of customer requests to change the notified maintenance plan. Given that the majority of requests to change the programme are customer led, any output incentive in this area will need to reflect customers' desire for flexibility.

For entry related planned maintenance, there is no provision for Maintenance Days set out in the UNC. Where Network Entry Agreements are in place with the upstream party, they facilitate outage information sharing to enable mutually beneficial co-operation, though there are no binding obligations on either party. Where agreement is not reached, capacity management tools such as capacity buybacks would be used to enable maintenance activities where they impacted upon flows. Therefore, the impact of maintenance at entry is already captured within the entry capacity operational buyback incentive. Similar arrangements apply relating to the commissioning of NTS assets though there is no explicit allowance currently within the buyback incentive target for this cost.

We believe that there is merit in exploring the feasibility of an incentive on us as gas SO for exit related maintenance scheduling and would also welcome views from the industry as to the materiality and nature of the issues they would like to see addressed. In order to inform whether further development of such a scheme is warranted and to appreciate how such a scheme could operate, we think the following points should be considered in assessing the suitability and structure of such a scheme:

- Appreciation of both Shipper and National Grid costs. For example, we may reschedule planned maintenance activities in response to Shipper requests at our cost and a potential cost saving to the relevant Shipper(s);
- We work collaboratively with the relevant Shippers and operators in order to best align maintenance schedules, with the aim of achieving minimal impact where possible. It is important for industry participants to engage in this process at the earliest possible stage and provide accurate maintenance plans for their facilities in order to deliver the most efficient outcomes for both parties;
- For entry related planned maintenance, there are commercial tools that can be utilised if needed to manage the risk and cost exposure to Shippers, for example

[6] Including Pipeline Safety Regulations 1996 and Pressure Systems Safety Regulations 2000
[7] Figures based on 2010 maintenance

Capacity Buy Back Option contracts. If the existing incentive ‘cap’ were to be removed from the entry capacity operational buyback incentive scheme, then we believe that it would be more appropriate to manage maintenance via ’exit style‘ maintenance days due to the high potential exposure to buyback costs when the work must be carried out in order to comply with our statutory obligations;

- For exit related planned maintenance we have, under the UNC, an allowance to call upon maintenance days due to the statutory nature of these activities and the general lack of alternative options and competition at NTS Exit Points. Compensation arrangements are already provided for under the Uniform Network Code where we do not adhere to the agreed maintenance timescales;
- Where multiple parties are affected, there may not be a solution that is appropriate for all parties and therefore backstop arrangements must be available to ensure that statutory obligations can be met; and
- There should be consideration of any outputs or incentives that may be interactive with maintenance planning and delivery.

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?

We welcome the opportunity to consider an SO incentive on customer satisfaction.

We are reviewing how to make best use of the stakeholder engagement and customer satisfaction work being undertaken as part of the RIIO-T1 process. The same incentive approach could be adopted for the SO (i.e. a customer satisfaction survey) but with a clear distinction between SO and TO activities within the surveys, as in some cases the limited customer base for survey sampling would be the same. The success of such an incentive would be dependent on the level of participation in such surveys; as such there may be merit in considering how such participation could be maximised. The customer satisfaction incentives could focus on 'how' we deliver our services, as 'what' we deliver is captured and measured through other outputs. This would ensure that there would be no double-counting across, or within, incentive schemes.

If a customer satisfaction incentive were to be in place for the SO, this would affect the charges levied to customers of the SO. Therefore, as mentioned in the consultation document, consideration would need to be given in the design of the incentive to ensure that there is a low risk of customers reducing their scores in order to seek reduction in their charges.

National Grid is committed to working with and understanding our customer requirements, and we currently collect feedback from our customers as part of our normal business. Therefore, if there were to be a licence obligation to collect such feedback, National Grid would want to ensure that the process remains as open and honest as possible such that feedback received is as accurate and useful as possible.

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

We agree with the principles of bundling that have been outlined within the consultation document.

To date, the bundling of electricity SO outputs has enabled efficient trade-offs between those outputs to deliver the most efficient overall result for consumers. However the success of bundling in electricity is largely down to the close relationship between outputs and the common means of managing them.

Bundling will be most effective where the level of risk and control over bundled outputs is similar and there exists the potential to trade-off the use of different means to achieve the same ends. We consider it important that the decision on whether or not to bundle incentives takes issues such as this into account, and does not sacrifice simplicity and transparency where those criteria are also of benefit.

We note that, when we have consulted with the industry in past on bundling of gas SO incentives, that they have valued the transparency of information, clarity of focus and appropriate cost targeting that can be achieved by separate incentives. We consider it important that, when deciding whether or not to bundle incentives, that the pros and cons of each approach are properly considered.

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

We consider that the proposed options for packaging outputs set out in paragraphs 4.10 to 4.24 are reasonable, although some flexibility may be required to accommodate new incentives or to change the level of bundling if unintended consequences arise.

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

We consider the current bundled approach to electricity SO incentive continues to be reasonable.

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?

Where the incentivised activity relates directly to avoided costs in the Balancing Mechanism (BM), the output should be treated as part of the bundled scheme. For some activities, consideration of unintended consequences may be needed (e.g. publication of a demand forecast which over-forecasts the expected demand may lead to a longer market, leading to a lower requirement of operating reserve). Where an activity may be of benefit to market participants but which does not relate directly to avoided actions in the BM, such as the provision of information, this would better be treated in a separate incentive.

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

Where there are material interactions between different activities, aligning or bundling incentives may have benefits in ensuring that the most efficient outcome can be promoted where efficient trade-offs can be made.

Conversely, unbundled incentives could lead to greater transparency of the different aspects with more accurate alignment of our actions to our customers' requirements. This would enable appropriate parameters to be set for each scheme and would allow specific areas of further work and performance improvement to be identified. Hence it is important to ensure that bundling is focused on the delivery of efficiencies that would not otherwise be directly realised.

One example of bundling within the current gas SO incentive structure is in the Shrinkage incentive, which already incentivises a range of behaviours whilst using uncertainty mechanisms to manage elements that are not within our control. The incentive covers the efficient energy and environmental management of the compressor fleet (gas and electricity), procurement of gas and electricity and management of calorific value shrinkage where appropriate to reduce the level of unbilled gas. Bundling in this instance has enabled a range of aims to be brought together in one performance measure, using uncertainty mechanisms to model the impact of shipper flows on compressor use and market movements on gas and electricity prices.

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

In order to build appropriate incentives, it is important to have a clear and measureable output, understand what behaviours and services the industry wishes to see and the relative value between these activities. Further detail for areas that may be incentivised is set out below:

<u>Residual Balancing</u>
The requirement to balance the network is largely driven by the actions of shippers in balancing their respective portfolios. Therefore, we consider that an incentive in this area should focus on the desired behaviour of ourselves as SO and the encouragement of market beneficial outcomes, rather than on the volume and or cost of its market balancing actions, especially as the price of gas is largely driven by the market.

<u>Demand Forecasting</u>
Our gas demand forecasting activities provide high level aggregated forecasts to the industry to enable them to make better commercial decisions. The current incentivised forecast is produced at the day ahead stage before all relevant information for the following gas day is contractually required from shippers. Therefore, our exposure to our forecasting performance should reflect our level of control over the output.

<u>Shrinkage</u>
In reviewing Shrinkage over the longer term, the following should be taken into account:

- Consistency with the network funded through the wider RIIO-T1 price control settlement;
- Mitigation of windfall gains or losses due to uncertainty in primary drivers (e.g. supply patterns);
- Procurement benchmarks reflective of market prices, risks and product availability; and
- Interactions with wider environmental obligations.

<u>Operating Margins</u>
In reviewing Operating Margins over the longer term, consideration should be given to how the service can be delivered for the various triggers and the control we have over those triggers to ensure that the most appropriate framework is put in place. The volume requirement for OM is calculated in order to fulfil our obligations under our Safety Case. However, in recent years National Grid has enabled wider participation in OM service

provision through the contestability work and has reduced costs of OM for industry in line with our aim to procure OM efficiently.

Capacity availability and management including buybacks
We consider that the following principles should be taken into account in the incentivisation of capacity availability:

- Exit capacity should be incentivised in a manner consistent with entry capacity, and given their close interaction, consideration could be given to combining both into a single incentive;
- Any incentive structure should encourage us as SO to provide innovative solutions to system constraints and the release of additional capacity;
- We agree that it is appropriate to consider incentivising the interactions between the SO and the TO in this area, in terms of investment and also operational activities such as maintenance;
- Consideration could also be given to incentive arrangements between the SO and shippers, to recognise the impact that some shipper behaviours (such as flow profiling) have on system capability; and
- An appropriate balance should be struck between the availability of capacity and the other outputs that stakeholders value, such as efficient system operation.

Following an incremental entry capacity signal, it may be economic and efficient to defer investment until such a time as there is a physical need case. In the event the assets ultimately need building, the overall funding needs to:

- Consider that there should be a reflection of some benefit for taking the risk associated with providing the most efficient solution;
- Recognise that a proportion of the remuneration may already have been received through revenue drivers and therefore should not be funded again;
- Account for both the inflation and real price effect factors that have occurred in the intervening period; and
- Take account of new planning and consenting standards that may now apply.

Additionally, it should be noted that there is an asymmetry of risk between the revenues associated with the current entry capacity buyback scheme and the risk of high costs, which would be accentuated if there were no caps or collars on this incentive. Clearly this issue is also of relevance at exit, where no incentive scheme is currently in place.

Greenhouse gas emissions
The current greenhouse gas emissions incentive covers the natural gas vented from compressors. We consider that the following principles should be taken into account in the emissions incentivisation:

- Vented emissions should only be subject to a financial incentive until these emissions are covered by EUETS or other UK/EU law (potentially 2018) and consideration should be given to reducing any risk of double counting emissions with the cost of gas already covered in shrinkage;
- Any developments in the measurement of and alternatives to venting[8];

[8] In March 2011 we accepted a new licence condition to develop a methodology to quantify the emissions and consider alternatives to venting natural gas.

- The overall environmental impact of an activity and cost to reduce the emissions to avoid any perverse drivers, i.e. actions to reduce emissions should be incentivised only where the cost of those actions is at or below the marginal environmental abatement cost. We consider that it would be inappropriate to penalise emissions that would cost significantly more than this value to abate;
- Reflect the drivers and level of control as there are legal requirements around safety and maintenance driven processes which can lead to venting; and
- The interaction between the SO and TO, as the most efficient emissions reduction techniques may impact on TO asset decisions to deliver emissions benefits over the longer term.

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

In packaging outputs, consideration needs to be given to the desired incentivised behaviours and how the outputs interact. We consider that there would be value in engaging with stakeholders on where there would be value in bundled or unbundled incentives. The objectives of the various SO activities could be grouped into providing and managing capacity, national balancing and compressor operation. However, in order to bundle outputs, detailed thought is needed to ensure that any interactions are material, no perverse incentives would be created and consideration is given to the level of control and the optimal incentive timescale for each output.

The existing linepack, residual balancing and demand forecasting SO incentives are based upon performance measures that incentivise specific market/competition enhancing behaviours rather than direct cost minimisation. In the consultation, one potential option proposed is to design a cost minimisation scheme, though in the case of some outputs this may be based on the second (or greater) order effects of the SO actions. Whilst this is possible, the merits and impacts on the market and competition between shippers and between suppliers would need to be examined carefully.

If a cost minimisation incentive structure were adopted, the nature of our actions in, and relationship with, the energy markets would change and this may also impact on the transparency of the operational and commercial impact of related SO actions.

Considering the specific interactions identified in paragraph 4.31:

Minimise GHG emissions from compressor venting and NTS shrinkage: There is alignment between these incentives; however the large difference in scale of volume between the two, and the environmental impact of the venting, would need careful consideration.

Capacity buyback and residual balancing: We will, where appropriate, take account of the likely impact of residual balancing actions on the use of capacity. For example, there may be a secondary impact of a national “sell” action if it leads to a reduction in flow at a terminal that is close to being constrained thus reducing the risk of a future capacity buy-back requirement. This should not, however, be confused with locational buy and sell actions, which are taken with the specific intention of alleviating an existing capacity constraint and are therefore already part of the entry capacity operational buy-back incentive. Although there is an interaction between the two activities the driver for each is very different. Costs associated with locational actions and capacity buybacks are directly linked whilst the residual balancing costs are associated with the relatively small trades that we undertake to both address pending system issues and to encourage shippers to address their portfolio balance through timely commercial activities. Linking the two would lead to a scheme that had unclear and complex interactions between actions and costs.

Residual balancing and demand forecasting: The total system demand forecast provides information to the community on the likely overall level of demand for the total system (NTS, Distribution Network (DN) and independent Gas Transporter (iGT) networks) for the following gas day whereas the residual balancing role responds to third party generated imbalances on the NTS. Although there is a relationship between total system demand forecast quality and the within day NTS system imbalance, the demand forecast is not the only influencing factor on the level of imbalance. Bundling these incentives is likely to reduce the transparency of SO actions and costs in this area.

The volume and timing of residual balancing actions is affected by Distribution Network (DN) stock change activities and upstream energy (oil, Liquefied Natural Gas (LNG)) prices especially where gas supply is linked to oil production, or flowing gas to the UK ranks second to meeting long term European market gas supply contracts.

NTS shrinkage and residual gas balancing: The interaction identified relating to the impact of the quality of shrinkage estimates on balancing, though likely to be arithmetically correct, is thought to be non-material when compared to system balance. Furthermore, bundling these outputs would be a material change from current arrangements and would rely on the residual gas balancing role being a volume incentive, which would cause complexity and reduce transparency as described above. Depending on the desired outcomes, there may need to be associated changes to UNC and licence in order to reflect the potential merging of control room balancing and shrinkage “shipper” gas trading / commercial risk management activities.

SO internal and external incentive schemes: We agree that the trade-offs between internal and external schemes need to be considered as part of any overall incentive package.

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

We agree that the consultation captures the potential benefits of moving to a longer term incentive scheme.

The environment in which National Grid operates is undergoing rapid change. Indeed, this is one of the drivers for moving from an RPI-X to a RIIO based price control framework. In this changing world, longer-term incentives should provide more time to undertake developments to promote efficiency. However it will be important to ensure there is sufficient potential for pay-back where efficiencies result; and appropriate uncertainty mechanisms are introduced to manage risk.

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?

The aim of multi-year incentives should be to provide stronger incentives to take a more strategic view of costs over that longer period and to embark upon courses of action that would either not be possible or would not allow for sufficient pay-back with a shorter incentive period, such as to encourage innovative alternative provision of SO services.

If these principles are considered in the incentive structure there should not be a material impact to the incentive properties whether longer-term schemes are implemented as a single block scheme or a series of annual schemes covering the same period, so long as the principles stated above are upheld.

The approach taken will dictate the issues managed through the scheme period. For example, a year by year incentive scheme might provide a sharper focus on certain functions and more stable charges, which are seen by customers as being important. However, a mechanism would need to be identified that allows payback over a longer period than a year, such that the incentive to take the long-term view is maintained. Multi year block incentives would remove the need for such a mechanism, but instead raise questions regarding how the impact of incentive performance on charges should be managed over that longer period.

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 proposed treatment appears reasonable. We note that appropriate uncertainty mechanisms have been fundamental to the delivery of a two-year electricity SO incentive scheme for 2011-13 and that the longer the scheme, the more important such uncertainty mechanisms become. However it is also important to ensure that the strength of incentive remains despite the use of those mechanisms.

Re-openers for ‘changes in government policy and new outputs’ as suggested in the consultation will be essential; and further re-openers to deal with changes to industry structure, such as a change from or to regulated prices in a sector or as a result of European code development, might also be necessary. A flexible approach to determining appropriate triggers for re-opening longer-term schemes, to balance continued incentivisation with removal of risk, would be beneficial.

The use of other adjustment mechanisms, such as the use of ex-post inputs and mid-term reviews should also be considered as part of the incentive consultation process.

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 a combined SO and TO, we recognise the significant benefits that common ownership can provide when seeking an overall ‘lowest cost’ solution. The inclusion of the SO viewpoint in the TO decision making process, both in terms of the delivery of assets onto the system and their ongoing operation, allows the TO to consider a wider range of options than it might otherwise have done. The electricity SO-TO Code (STC) seeks to contractualise this relationship to promote similar interaction with the other electricity TOs, such that similar efficiencies can be delivered.

We have consulted with the industry previously on this issue, and as a result of that work made a number of changes to the STC to improve the potential for the SO perspective to be included in TO decisions regarding capital schemes and outage plans. Better alignment of incentives on the SO and TOs has the potential to deliver further improvements in this area.

We note the importance of agreeing an appropriate baseline level of service to be provided by the TOs as part of the RIIO-T1 process; and of ensuring that if a mechanism were to be put in place that incentivises the TO to deliver incremental changes to that baseline level of service in order to meet SO requirements, it does not encourage sub-optimality in initial plans.

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 roles of the SOs and TOs are intrinsically linked with the TOs providing the physical network for the SOs to operate, enabling network and operational services to be provided to consumers. However, the timescales within which the SOs and TOs operate are different. This leads to important challenges in aligning incentives such that the risk/reward framework allows for effective trade-off of options and sufficient pay-back period.

We note that, as part of the RIIO-T1 process, an ‘efficiency incentive rate’ of 40%-50% is being proposed for operational and capital expenditure, compared to the different incentive rates currently in place[9]. Alignment of incentive rates between operational and capital expenditure would allow for more transparent cost trade-offs to be made. However, we believe that it would be appropriate to collar our exposure for certain costs as outlined earlier in this response.

To promote efficient SO and TO alignment, the parties providing these roles need to work together regardless of whether these roles are fulfilled within the same company or by different entities. It is important to make sure that network investment, operational solutions and system access in particular are co-ordinated between the SO and TO in order to meet the needs of current and future customers in an efficient and economic manner. Specific measures to promote greater SO-TO alignment would need to be carefully considered to avoid any unintended consequences.

Good and open communication between the SOs and TOs is vital to ensure that, where there are opportunities to make more efficient combined decisions, these are recognised by both parties so that they can be appropriately taken forward. The impacts of any opportunities to change from a baseline plan need to be understood by both the SO and TOs, to enable holistic decision making. For example, moving an outage on a part of the network may reduce short term costs but could adversely impact on other planned works. This particular area is discussed further below.

Behavioural interactions

System access is an important consideration for the SO and TOs in delivering the services required by customers. This includes connections, maintenance, renewal of infrastructure and maintaining access to, and flexibility of, the system for existing customers. The deliverability of the outage plan is a fundamental driver of efficiency in delivering construction and maintenance activities.

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[9] Baseline capital expenditure is subject to a 25% efficiency rate currently, and operational expenditure is subject to a range of incentive rates from 20% to 100% for the gas transmission network depending on the level of control for that type of expenditure and 100% for the electricity network operational expenditure.

Work is bundled where possible to minimise effect on consumers. As the workload to deliver connections and asset replacement increases, this is likely to become more prevalent, with a corresponding impact on when works are required to ensure that the outage plan is deliverable.

Alignment of incentives under common SO/TO ownership enables trade-offs to be made on a more straightforward and transparent basis, such that a range of issues can be considered in planning access to the system for works required including:

- The extent to which construction and maintenance activities can be bundled into an optimum number of outages;
- The ability to move outages given potential knock-on impacts to other works and outages within the plan;
- The costs and risks of the TOs associated with outage changes; and
- The expected costs and impacts of any constraints to the SO and consumers as a whole.

The complexity of these trade-offs is influenced by constraints in the number of outages that can be taken at any time in order to reduce the impact on the end consumer by maintaining system availability. This can mean that, as workload increases in constrained areas of the network, the planned schemes are increasingly interactive. This can also mean that the overall impact of outages changes can be difficult to quantify discretely for any one scheme.

There is currently a mechanism in place that enables the Electricity SO to pay the Scottish TOs for actual costs relating to changes to outages. This mechanism is not frequently used for reasons which include:

- There may not be enough time to re-schedule outages (e.g. to track generator outages) or re-scheduling of work may not be possible due to the availability of resource;
- The TOs are incentivised to invest at lowest cost which may reduce opportunities for flexibility to be built into construction contracts (e.g. weekend working) to reduce outage costs; and
- A high level of construction activity is currently taking place to reinforce the transmission systems – this is expected to increase following the introduction of the electricity ‘connect and manage’ regime. The tight schedule for delivering the construction programme may be restricting the movement of outages.

National Grid notes that some of the issues outlined above may fall away and allow increased use of the mechanism if the arrangements for funding outage change costs are extended to match the duration of longer-term, aligned incentives on the SO and TOs.

Capital Expenditure interactions

SO involvement in TO decision making has the potential to enable incremental investment within baseline schemes that would be of overall benefit to consumers. Such involvement can deliver:

- Reduced cost and/or environmental impact of the operation of assets (for example by investing in more expensive equipment that is more efficient to operate and hence has lower overall lifetime costs);

- Reduced impact of that investment on system access requirements (for example by using bypasses to enable impacts on system availability to be minimised whilst work is undertaken);
- Prioritisation of certain works within a scheme, where such works help manage the operational impact of delivering that scheme; or
- The building in of flexibility or redundancy to facilitate future expansion with minimal impact on system availability.

Further, there may also be projects that could be driven primarily by SO needs, for example voltage control equipment or quadrature boosters to manage system flows on the electricity system. If SO and TO incentives can be aligned such that the types of interaction highlighted above can be further encouraged, there is the potential to deliver more efficient system investment and operation, to the ultimate benefit of consumers.

To allow such interactions and trade-offs to take place, an appropriate level of information exchange needs to take place between the SO and TOs. National Grid has developed the Whole Life Value (WLV) Framework, to help balance the priorities of its SO and TO functions within investment decisions as explained in further detail below.

Whole Life Value

The WLV Framework is designed to consider a wide range of requirements for investments, such that the most effective solution (not necessarily the cheapest in the short term) can be determined.

In order for National Grid to respond to the forthcoming challenges, against an increasingly dynamic and uncertain supply and demand background, it needs decision tools to ensure that optimum, consistent and innovative investment decisions and technology choices are made considering the requirements of the SO and TOs. These need to take account of the shorter and longer term needs of the UK electricity and gas industries, including their stakeholders and customers, to create long term, optimised investments of enduring value.

Asset management decisions need to consider the whole asset life cycle from initial definition and design option selections through maintenance and operational flexibility and efficiency to final decommissioning and disposal. SO input is particularly valuable when considering versatility, operating expenditure, performance, system access and environmental impacts.

Evaluation of the value of alternative options is particularly important at the earlier stages of design and optioneering processes.

Subject to the ability to exchange relevant information, it is equally applicable to consider the whole life cycle of an asset considering the requirements of the SO, TO and other stakeholders whether the assets are under an integrated SO-TO or in separately-owned TOs. Fundamental to the success of this approach is the early involvement of the SO in the decision making process.

Trade-offs between Asset Investment and Contractual Solutions

An important interaction between the SOs and the TOs is in understanding which is the most appropriate party to manage a given requirement, such as to respond to customer requests for new connections or increased capacity. For example, an efficient trade-off may consider TO investment solutions against SO contractual options to deliver that requirement. In these cases, priority alignment and appropriate funding mechanisms are particularly important for the SOs and TOs. These trade-offs are already evident as set out below, but any work to further consider SO and TO interactions should ensure that continued interactions in this area are maintained.

Load related investment can be required to extend or reinforce the electricity and gas networks, driven by customer requests for new connections or increased capacity. In most cases, load related investment is underpinned by a signal for incremental capacity above the prevailing obligated level and an associated revenue driver agreed with Ofgem.

Investment is formally progressed following a signal for capacity, such as through the Quarterly System Entry Capacity (QSEC) long term auction process for gas entry capacity, or following receipt of an application to connect to the National Electricity Transmission System. There are a range of options available to meet customers' needs, which need to consider the expected, and risk of, costs and consequential impacts on the SO and TO:

- Do nothing, which may be an option if analysis shows the risk introduced by the incremental capacity is acceptable and can be managed operationally. Options here may include operational intertrips and gas capacity buybacks;
- Seek a contractual solution;
- Invest to provide additional physical capacity;
- Substitute capacity from another point on the network; and
- A combination of the above options.

Where system constraints are forecast to occur infrequently, or are not expected to be enduring, there is potential for commercial alternatives to provide a more economic solution than physical investment. Investment in physical assets has a long lead time, large fixed costs and relatively low marginal costs. This can be compared to on-the-day commercial actions, which in comparison, can have much shorter lead times, lower fixed costs and higher (although unpredictable) marginal costs. Contractual forms can provide an option between the two extremes.

In order to make efficient trade-offs between whether to invest in assets or use operational solutions at any stage, we would need to seek comfort that the enduring need for any operational solutions would be recognised in future price control periods, whether in the form of an appropriate allowance or within the Regulatory Asset Base.

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?

National Grid considers that TOs should be appropriately funded for actions taken to improve overall system efficiency. If TOs were incentivised to reduce costs without due consideration of SO costs then the opportunity to reduce overall costs for consumers would be lost.

The general aim of the proposed provisions appears to be to allow the TOs to share in the benefits of actions taken by them to promote overall system efficiency that have been initiated by a request from the SO. The means by which this could be achieved would need to be carefully considered to ensure that it does not have any unintended consequences (e.g. if the TO develops a suboptimal plan in expectation of benefits from subsequent revision).

To investigate these issues further we consider behavioural and capital expenditure interactions separately below.

Payments to encourage behavioural interactions
The example quoted in paragraph 6.30 of the consultation has the SO making two payments to the TO to reduce the duration of an outage; one to cover the costs incurred in physically delivering a shorter outage and one to act as an incentive to do so. The example notes that National Grid is well placed to evaluate the potential efficiencies that might be gained from TOs taking certain actions, and to make a call on whether or not the risk of incurring operational costs could be mitigated by requesting TOs to take action.

A key question is how the incentive payment would be determined. Whilst a payment to cover actual costs incurred is fairly straightforward, payments for incentives tend to be based on a measure of the efficiency delivered. National Grid notes that, if this incentive payment is not linked to the actual benefit delivered by the action, there is a risk that the incentive payment will merely increase the cost of delivering the shorter outage, to the overall detriment of consumers.

Payments to encourage capital expenditure interactions
Capital expenditure interactions could manifest themselves through the application of the WLV Framework principles across TOs or via specific requests from the SO.

The example quoted in paragraph 6.38 has the SO applying to the TO for additional network capacity or capability. This presents a number of questions:

- **Timings:** The process of identifying capital expenditure requirements and proceeding from application through to delivery could take a number of years. Even with an SO incentive aligned to an eight year price control, there is the possibility that the SO will see limited benefit within the scheme itself;
- **Payback period:** Given the issues with timing just outlined it might be that there is little chance of the SO benefiting within the incentive period, although if allowed into its regulatory asset base the TO would earn a rate of return over the life of the asset.
- **Payments:** Would the SO be paying for (and owning) the assets themselves, or paying a cost/incentive payment for the TO to fund, build and own the assets on the basis of the SO requesting the assets (and be granted the required revenue and the ability to incorporate the assets into their Regulatory Asset Base (RAB))?

National Grid notes the potential interactions between the SO external cost incentives[10] and the TOs' price control arrangements, and that the design of an incentive mechanism to encourage capital expenditure interactions would need to be carefully considered to avoid unintended consequences. However a robust means by which the SO can influence TO investment in network capability has the potential to deliver efficiency in system operation. It is important that such an incentive places incentives to deliver efficiency through the whole scheme period; rather than being dependant on large scale actions that could take a number of years to implement.

[10] I.e. The Balancing Services Incentive Scheme (BSIS) for electricity transmission and the range shallow incentives for the gas National Transmission System. For further information on the SO external cost incentives please see http://www.nationalgrid.com/uk/Electricity/soincentives/ and www.nationalgrid.com/uk/gas/supportinginfo.