



Promoting choice and value
for all gas and electricity customers

System Operator incentive schemes from 2013 initial proposals:

Overview

Consultation

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Publication date:	27 July 2012	Team:	Markets
Response deadline:	21 September 2012	Tel:	020 7901 3874
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Overview:

This paper sets our initial proposals for incentives on the gas and electricity System Operators (SOs) from April 2013. Our proposals are based on RIIO (Revenue = Incentives + Innovation + Outputs) principles for regulating monopoly energy companies.

We put forward proposals for a range of incentives for gas system costs and outputs, and for electricity outputs, covering a period of up to eight years. For the electricity costs scheme we propose a different approach, moving away from complex modelling and focussing more on establishing principles and monitoring outcomes with financial incentives consistent with this approach.

We seek views on all aspects of these proposals and in particular whether they will encourage the right behaviours from the system operators and provide value for money for present and future consumers.

*Responses are sought by **21 September** to inform final proposals later this year.*

Context

These initial proposals form part of our work to regulate monopolies effectively. We consider that it is important for both the electricity and gas markets that the role of the System Operator (SO) is correctly identified and that the SO has the appropriate tools available to it to undertake this role.

Any interventions in the market by the SO can lead to costs being incurred, both directly by the SO and more widely by the market. Since consumers ultimately bear these costs it is important that they are efficient. The SO also has a wider role than its core balancing activities and we consider that it is important that the SO has the appropriate incentives to play a full role in delivering a sustainable energy system.

This work builds on previous material published in both SO incentive schemes and RIIO-T1 documents.

Associated documents

- System Operator incentive schemes from 2013 initial proposals: Supplementary appendices. 27 July 2012:
<http://www.ofgem.gov.uk/Markets/WhIMkts/EffSystemOps/SystOpIncent/Documents1/appendices%SO%2013.pdf>
- RIIO-T1: Initial Proposals for National Grid Electricity Transmission plc and National Grid Gas plc, 27 July 2012, Ref 104/12:
<http://www.ofgem.gov.uk/Networks/Trans/PriceControls/RIIO-T1/ConRes/Documents1/RIIO%20T1%20Initial%20Proposals%20for%20NGGT%20and%20NGET%20Overview%20707212.pdf>
- Decision on the concept for the implementation of the Environmental Discretionary Reward for the electricity transmission owners and system operator, 4 July 2012:
[http://www.ofgem.gov.uk/Networks/Trans/PriceControls/RIIO-T1/ConRes/Documents1/RIIO-T1%20-%20Environmental%20Discretionary%20Reward%20\(EDR\)%20decision%20letter.pdf](http://www.ofgem.gov.uk/Networks/Trans/PriceControls/RIIO-T1/ConRes/Documents1/RIIO-T1%20-%20Environmental%20Discretionary%20Reward%20(EDR)%20decision%20letter.pdf)
- System Operator incentive schemes from 2013: principles and policy, 31 January 2012, Ref 12/12:
<http://www.ofgem.gov.uk/Markets/WhIMkts/EffSystemOps/SystOpIncent/Documents1/SO%202013%20Principles.pdf>
- System Operator incentive schemes from 2013, 14 June 2011, Ref 77/11:
<http://www.ofgem.gov.uk/Markets/WhIMkts/EffSystemOps/SystOpIncent/Documents1/SO%20incentives%20from%20April%202013%20Initial%20Views%20Consultation.pdf>

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Executive summary

The gas and electricity systems will go through significant change over the coming years including major reforms in the UK (Electricity Market Reform) and in Europe (European Target Models). The way the electricity system is operated will need to adapt to accommodate a more intermittent generation mix, more interconnection and a more integrated way to trade across borders with neighbouring countries. The gas system will have to adapt to accommodate a more variable use of gas as a result of intermittency in electricity and, potentially, an increase in storage and LNG facilities.

Meeting these challenges will require the System Operators (SOs) to play a full role in delivering a sustainable energy system that is robust to the challenges they face. Playing a full role will require the SOs to take a proactive approach and take appropriate actions to reduce the impact of these challenges to SO costs. It will also require them to think longer term, anticipating future challenges to deliver long term value for money for consumers. In doing this the SOs will have to work with others and take account of the interactions with all energy market participants including in particular the Transmission Owners (TOs).

To support and encourage the SOs to play a full role we are changing the way we regulate them. Consistent with the approach we are taking for the transmission business price controls, the proposals we outline in this document are based on the RIIO (Revenue = Incentives + Innovation + Outputs) principles for regulating monopoly energy companies. These principles ensure that sustainability and the needs of both current and future consumers are at the heart of regulation. This will be the first SO regulatory framework based on the RIIO principles.

One of the key components of the RIIO principles is to encourage long term innovative thinking through a clear, transparent and stable regulatory framework. As with the network businesses more generally, we have concerns that the SOs have been too focussed on short term cost reduction and on managing the regulatory relationship, and have not been sufficiently innovative or creative in seeking "software" solutions rather than investing in "hardware". Innovative behaviour may also include shifting the focus from efficiently operating under current market arrangements to seeking to improve those arrangements.

For the electricity SO, National Grid Electricity Transmission (NGET), we have identified outputs and costs that could be incentivised. However, our view is that the significant changes that are occurring to the electricity market make it difficult to derive robust cost targets for the SO, which do not require regular revisiting and revision. We recognised the problems in setting appropriate targets in 2010 and have been working with NGET to see whether it is possible to develop more reliable models. However, despite using new "bottom-up" models of balancing costs to derive target costs since 2011, it has become clear that the accuracy of the models in forecasting costs remains a major issue. NGET's proposals for incentives from 2013 are based on models that are significantly more complex than the current models but still seem unlikely to be robust.



Therefore we are proposing to remove short-term financial incentives based on detailed modelling of balancing costs in favour of a broader incentive approach. This is designed to encourage more innovative behaviour while recognising the increasing challenges that are likely to be associated with balancing the system. We propose to clarify and, where necessary, extend the current obligations to make clear that actions to reduce balancing costs should be considered “business as usual” for the SO. We will monitor closely the level of balancing costs and work to increase the transparency of these costs to stakeholders.

We also propose introducing a licence condition that will enable us to disallow costs that NGET has incurred if we can demonstrate that they are inefficient. At the same time, we wish to encourage NGET to shift its focus from short term minor improvements to “making a difference” in the way it operates the system and thereby ensure that it plays a full role in delivering a sustainable decarbonised electricity market. Consequently, we propose that NGET could be able to retain a proportion of any measurable net benefit to consumers resulting from the actions it takes that go well beyond “business as usual”.

We consider there is merit in retaining output incentives on NGET. For example, recognising the increasing role of intermittent generation, we are proposing to introduce a financial output incentive on NGET’s renewable forecasts. Via RIIO-T1, we are proposing to have output related incentives on innovation, environmental performance and stakeholder satisfaction. The RIIO-T1 work on the development of SO-TO interactions (as part of the Network Access Policy) will also consider incentives.

Separately, in response to the wider changes occurring in the electricity market, we will press ahead with our ongoing reform work, the aim of which is to achieve efficient balancing and system operation in the context of the European Electricity Target Model in Great Britain (GB), including reviewing the cash-out arrangements. Alongside the substantial increases in transmission investment provided for under the RIIO-T1 proposals, we consider this work is needed to address the longer term challenges of balancing costs.

For the gas SO, National Grid Gas (NGG), we are proposing incentives that follow the RIIO approach and focus on outputs and costs. Our proposals broadly follow those included in NGG’s business plans, build on past experience of incentivising the gas SO and include some improvements to allow for long term incentives and to take fully into account SO and TO interactions. We have removed some incentives where they are not needed, and added others in direct response to stakeholder input and consultation responses. In particular, we are proposing new output incentives related to the accuracy of demand forecasts for two to five days ahead, and to the number of and changes in maintenance days.

For the gas schemes and electricity output incentives we recognise that market and regulatory developments may require the proposals to be adjusted during the incentive scheme period and have included proposals for uncertainty mechanisms to deal with such situations.

*Consultation on the Initial Proposals closes on **21 September 2012**. Responses should be sent to soincentive@ofgem.gov.uk. In November 2012 we will publish Final Proposals and consult on draft licence conditions.*



1. Introduction

In this overview document we set out the context for the initial proposals and a high level summary of those initial proposals. Readers who would like further detail on the initial proposals are referred to Appendices 2 and 3 (Electricity System Operator output and cost incentives) and Appendices 4 and 5 (Gas System Operator output and cost incentives).

Where this consultation sits in the process and next steps

1.1. This document, and the appendices published alongside it, begins our consultation on initial proposals for incentives for the gas and electricity System Operators (SOs) from April 2013. This is part of a process that began in June 2011. Table 1 below sets out the process so far and, in italics, an overview of the anticipated process from the publication of these initial proposals until implementation in April 2013.

Table 1: Setting incentives from April 2013: process and next steps

Date	Action
June 2011	Published consultation "System operator incentive schemes from 2013" setting out initial views on the principles that we consider should underpin longer term SO incentive schemes to apply from April 2013.
January 2012	Published consultation "System Operator incentive schemes from 2013: principles and policy" setting out proposed objectives, policy and principles for the regulation of the SOs from April 2013.
May 2012	The gas and electricity SOs (NGET and NGG) submitted their business plans setting out their proposed incentive schemes from April 2013
27 July 2012	Consultation on Initial Proposals for incentive schemes from April 2013 (this document)
14 September 2012	<i>A workshop with stakeholders to discuss our Initial Proposals (this will also be an opportunity to discuss SO-TO alignment issues covered in these initial proposals and in the RIIO-T1 initial proposals)</i>
21 September 2012	<i>Consultation on the Initial Proposals closes. Responses should be sent to soincentive@ofgem.gov.uk</i>
November 2012	<i>Publication of Final Proposals and consultation on draft licence conditions</i>
February 2013	<i>Decision to modify the licence to be issued</i>
April 2013	<i>SO incentives in place</i>

1.2. The 14 September workshop to discuss these initial proposals will be held at Ofgem, with registration at 10.30am for an 11am start. The morning session (11am – 1pm) will cover gas and the afternoon session (1.45pm – 3.45pm, with lunch and



registration from 1pm) will cover electricity. If you are interested in attending the workshop, please email soincentive@ofgem.gov.uk stating your name, job title, company, and whether you will be joining for gas, electricity (or both sessions) and whether you will be attending for lunch. Please respond by **5 September 2012** and note that places are limited.

The role of the gas and electricity SOs

1.3. For both gas and electricity, National Grid as the System Operator (SO) is responsible for balancing the system on a continuous basis across GB. To do this, the SO buys and sells energy and procures associated services. It also provides other services to market participants, such as forecasts of demand. The SO is obliged to perform its role in an economic and efficient manner.

The evolution of the SOs' role in the wider market and policy context

1.4. As we set out in our January 2012 consultation, the electricity and gas SOs are facing a number of challenges and opportunities which could significantly change the way they need to operate their systems:

Decarbonisation of the energy supply:

- As increasing levels of wind and other types of renewable generation come on line, the associated increase in intermittency will require additional reserve (to ensure that additional generation is available should output from intermittent generation reduce).
- As renewable generation connects to the system before network reinforcement takes place (and as thermal generation is decommissioned) network flows are likely to change. The impact of these changes is likely to be higher volumes of more volatile constraints on the system.
- As more intermittent generation connects to the electricity network, the demand for gas fired generation is likely to become more variable. In addition, more storage and LNG facilities are likely to connect and there will be a need to manage this.

Increased interconnection capability and implementation of policies to increase market integration at a European level:

- In the European context the development of network codes in several areas (including balancing, system operation and grid connection) will affect the SOs' interaction with neighbouring gas and electricity markets.
- Electricity interconnector capacity is forecast to increase significantly from its current level of 3.5GW and this may bring additional complexity to system operation as well as benefits.

Maintaining security of supply in the face of decarbonisation and declining stocks of fossil fuels:

- This may require the SOs to improve system management (eg through the facilitation of demand side response) and to take advantage of initiatives developed at EU level (eg ensuring that interconnectors are used efficiently).



1.5. We have already started seeing evidence of changes in the GB market and their significant impact on electricity system operation in particular. Constraint costs have increased from £84m in 2005-6 following the introduction of the British electricity trading and transmission arrangements (BETTA) to £320m in 2011-12. There have been several high profile incidences this winter of high constraint costs at times of high wind generation and low demand. As the penetration of wind increases, more intermittent generation with low load factor will share network resources with thermal generation putting pressure on the way constraints are managed in the system.

1.6. We have also recently published an open letter on the issues around the implementation of the European Electricity Target Model in GB from 2014¹. The Target Model mandates changes to existing market arrangements to remove obstacles to cross-border trade and the implementation of market coupling. It also requires us to consider price zones to manage internal constraints and proposes harmonizing specification, use and procurement of balancing products and the cross-border sharing of balancing resources in the form of a common merit order. The implementation of the Target Model could impact on system operations:

- Efficient use of interconnectors, including intraday, could make it easier for intermittent generators to export any surplus to neighbouring markets, potentially alleviating SO's balancing and constraint management costs.
- Constraint management, currently the biggest single cost for the SO, could change if price zones are adopted.
- Cross-border balancing and sharing of reserves could provide for additional balancing resources and improve system security.

1.7. In addition to these changes, which mainly impact on how the SO performs its core balancing functions, the SO role may also evolve as a result of Government policy. In particular, the Department of Energy and Climate Change (DECC) intends to confer the Electricity Market Reform delivery function on the electricity SO. The proposal that the electricity SO will be responsible for delivering the capacity mechanism and Feed-in tariff contracts for difference (FIT CFDs) will expand the SO functions and give the electricity SO additional responsibilities. We are currently conducting a joint project with DECC to assess the extent to which the SO performing the EMR delivery role creates new conflicts of interest and/or new synergies for National Grid. It may be that the outcome of EMR project, and the joint project on conflicts of interest and synergies, significantly changes the role of the SO, and requires a reconsideration of SO incentives.

1.8. Finally, Ofgem's Integrated Transmission Planning and Regulation (ITPR) project and associated workstreams will consider whether improvements are needed in the longer-term to the electricity SO's role and incentives as system planner across the whole of the national electricity transmission system. It is also considering whether the current governance arrangements, relationships with other parts of National Grid and with other transmission parties in GB, can best deliver efficient system planning.

¹ <http://www.ofgem.gov.uk/Europe/Documents1/EU%20Target%20Model%20open%20letter.pdf>



Playing a full role

1.9. In addressing these challenges and opportunities, and in anticipating and responding to what may be significant policy changes, it is important for the GB energy sector to achieve a successful transition to low-carbon that the SOs play a full role in that transition. Playing a full role includes:

- Taking a proactive approach and taking appropriate actions to reduce the impact of challenges on the costs of performing the SO functions (eg developing the use of demand side response in system balancing).
- Thinking longer term to anticipate future challenges and deliver long term value for money for consumers.
- Thinking innovatively and strategically about market operations and trading arrangements.
- Working with others and taking account of the interactions with all energy market participants (eg how the SOs work with the TOs to manage constraints).



2. The purpose of SO incentives

2.1. The rationale for setting SO incentives is:

- System operation is a natural monopoly activity. Monopoly companies tend to face little of the market discipline that spurs firms facing competition to deliver high quality and / or low costs.
- As the SOs are subject to licence conditions that require certain objectives are met (such as security of supply), they may have an incentive to over spend ('gold plating') to ensure these objectives are met.
- The two problems described above are exacerbated as the costs the SOs incur are reflected in charges they levy on shippers, suppliers and generators. These stakeholders pass the charges through to end users in their energy bills. As such there is no direct countervailing buyer power to keep costs in check.
- There is an information asymmetry in the SOs' favour that means that more direct 'command and control' style regulation would be inefficient as Ofgem knows less about what is possible in terms of quality and cost than the SOs. This restricts the ability of Ofgem to prescribe what the SO should do in precise terms (as it may prescribe costs or outputs that are not challenging enough or are unachievable).

2.2. Incentives, by working with the grain of the market, aim to overcome these problems. The principle behind incentives is to set realistic targets on outputs and costs with penalties for failing to reach, or rewards for doing better than, the target. This removes the need for Ofgem to prescribe exactly what the SOs should do and instead gives the SO the incentive to take economic and efficient actions, in the context of its own cost function and capabilities.

2.3. In practice, the incentive payments and penalties work through the charges that the SOs levy on users of the systems (generators, suppliers, shippers). Where, for example, the SO works to reduce the costs of a particular activity below the target, the SO gets to keep a pre-defined proportion of that cost saving by not being required to pass 100% of that cost reduction through to system users in the form of reduced charges for using the SO's system. Where actual costs are in excess of the target, the SO is prevented from increasing system user charges to fully recover those excess costs and is therefore penalised by having to bear a proportion of excess costs itself.

Setting incentives in line with the RIIO framework

2.4. Since early 2011, we have been working on setting new incentives for the SOs in line with our RIIO (Revenue = Incentives + Innovation + Outputs) framework. The most important aspect of this work has been to establish incentives that focus the SOs on "right" behaviours – to encourage them to play a full role in the transition to a more sustainable energy sector. As with the network businesses generally, we have been concerned that the SOs have been too focussed on short term cost reduction and on managing the regulatory relationship, and have not been sufficiently innovative or creative in seeking "software" solutions rather than investing in "hardware". Part of the conservatism of the SOs has been to focus on



efficiently operating under current market arrangements rather than seeking to improve those arrangements. The details of the incentive schemes are a means to get the SOs to focus on the “right” behaviours.

2.5. We have aimed to align with the approach we are taking for the SOs with the transmission business price controls under RIIO-T1. The RIIO framework aims to:

- **Focus the SOs on delivery of outputs:** we set out what outputs the SOs will be held to account to deliver and set suitable incentives relating to these outputs through licence requirements, reputational incentives and financial incentive schemes. We also set out how output incentive schemes may be adapted over time.
- **Focus the SOs on delivering outputs at long term value for money:** we set cost targets and upfront sharing factors that determine how cost reductions (or increases) are shared between the SO and consumers. The cost incentive schemes include uncertainty mechanisms where appropriate.
- **Focus the SOs to work with the TOs to reduce overall costs of system operation:** we set out outputs and cost incentives taking into account the interactions between the SO and TO roles and the interactions of incentives on them. Also, recognising in particular that constraint costs are likely to rise as more renewable generation connects to the system before network reinforcements take place, we are working to encourage behavioural changes, for example in the management of network outages.

2.6. Our aim has been to put the objectives, principles and policies of the SO regulatory frameworks in place for eight years (until end of March 2021). However, as recognised by respondents to our earlier consultations, this would not be appropriate in several areas and we propose setting some incentive schemes for a shorter period. We have also considered mechanisms to allow for changes to be made to individual incentive schemes, or to the set of schemes, during this period.



3. Performance of the SO against the incentive schemes

3.1. We have been setting SO incentives in broadly their current form since 2001. The schemes incentivise the SOs to take actions that are consistent with economic and efficient outcomes when undertaking their activities (eg buying energy to balance the system). The schemes generally provide cost or output targets which the SO is rewarded for beating or penalised for missing, subject to caps, floors and sharing factors. This section reviews the performance of the SOs against the incentive schemes between 2005 and 2012, as context for our proposals.

Performance of the Electricity SO against the incentive schemes

3.2. The electricity SO has a single financial incentive scheme target – the Balancing Services Incentive Scheme (BSIS) - that represents the combined costs associated with a number of discrete SO activities. The discrete schemes cover two main areas:

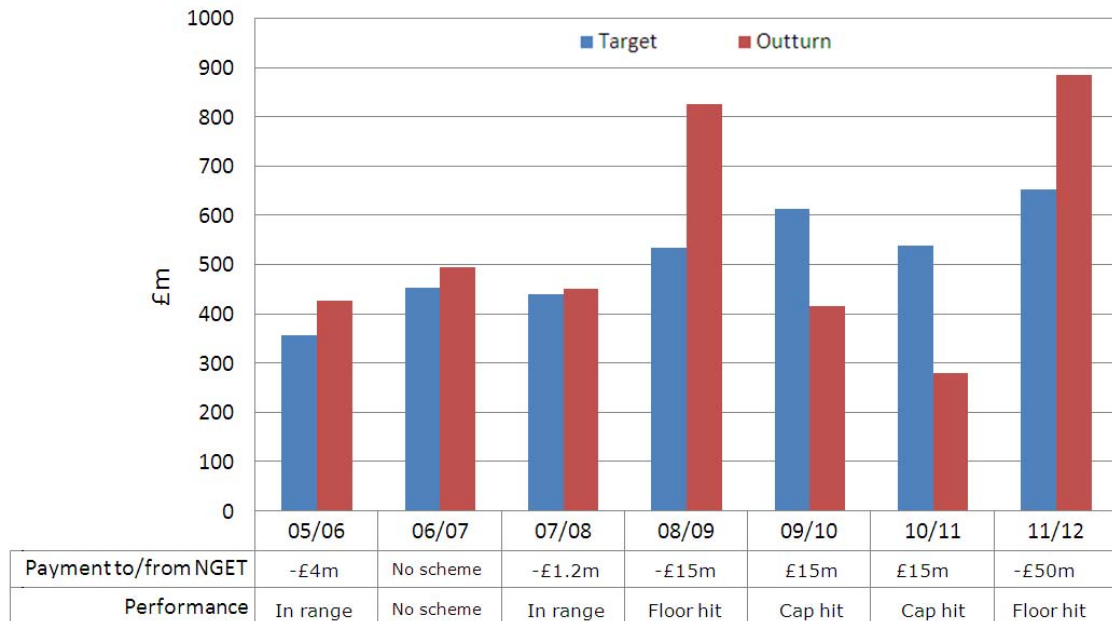
- The services the electricity SO provides in terms of balancing the system to ensure that demand and supply match (STOR, energy imbalance, black start, transmission losses, etc). ('Energy costs.')
- The costs the SO incurs in managing constraints on the system. ('Constraints costs')

3.3. Figure 1 shows the performance of the electricity SO against its incentive schemes over the last seven years².

² In 2006/07 there was no incentive scheme in place for electricity. Instead we relied on monitoring. The "target" for 2006/07 shown in figure 1 shows our ex ante forecast.



Figure 1: Performance of the electricity SO against the incentive schemes: Target v Outturns (2005 – 2012)



3.4. As can be seen, performance and targets have diverged significantly since 2008 as the volatility of outturns has increased. In 2010-11, for example, the outturn was £280m against a target of £539m, leading to the maximum capped incentive payment to the SO of £15m.

3.5. The increasing volatility in SO costs from 2008 means that it has become more difficult to set an appropriate target on an ex ante basis. Recognising this, in April 2010, we put in place a licence obligation on the electricity SO to cooperate with a comprehensive review of its incentive methodology, including its models and modelling approach.

3.6. As a consequence of our review substantial changes were made to the models and incentive methodology from April 2011. This attempt to improve the ability of the models to deal with greater volatility increased significantly the complexity of the models and methodology underlying the incentives. Indeed, several stakeholders have argued that the models used by NGET as the basis for incentive scheme targets are overly complex and that this makes it difficult for them to comment meaningfully on the proposed schemes and on NGET's performance against the schemes.

3.7. This greater complexity has not significantly improved the ability of the models and methodology to deal with volatility, as can be seen from Figure 1. In 2011-12, the cost of operating the system to consumers was £886m against a target of £654m. If this performance continued, NGET would have been subject to the maximum performance penalty of £50m when the scheme expires in March 2013. We understand that further modelling errors have come to light in respect of April and May 2012, which would change the outcome to a £50m reward to NGET. NGET are currently consulting (the consultation closes on 10 August), as permitted by the



licence, on changes to the model to be applied retrospectively which could result in a different target.

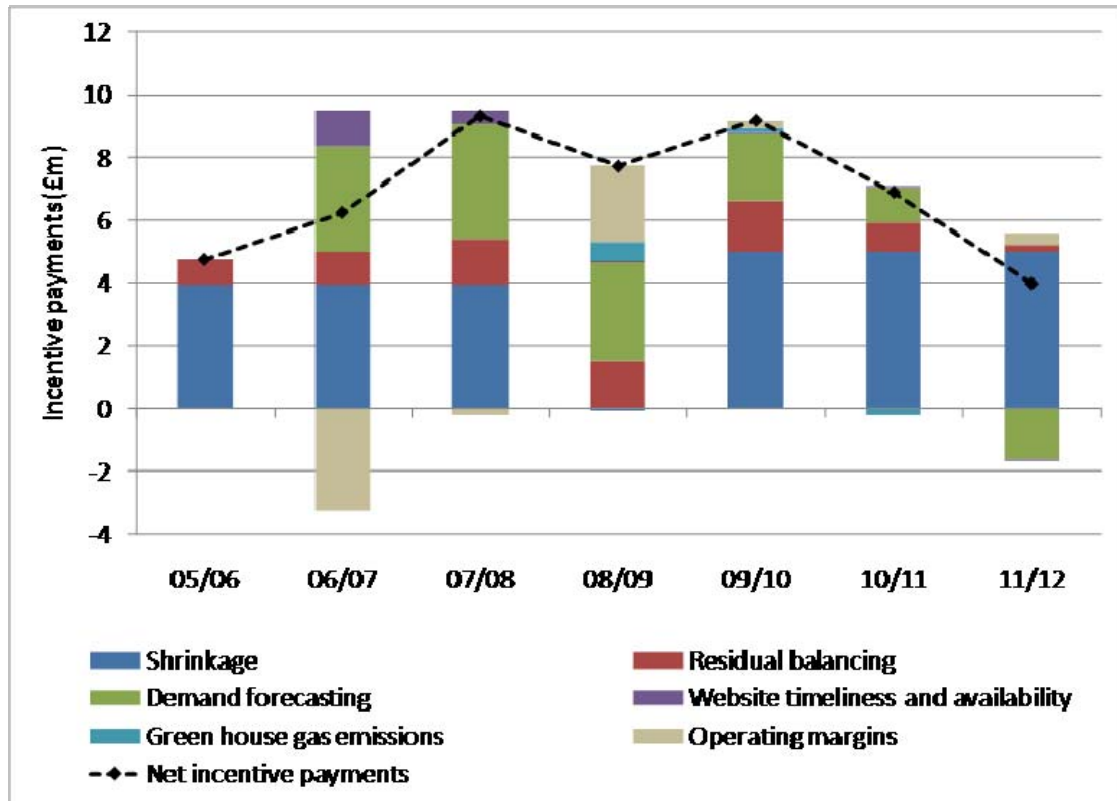
Performance of the Gas SO against the incentive schemes

3.8. The gas SO currently has six separate financial incentive schemes. While the way some of the schemes work has changed significantly over time, the aim of each scheme has remained broadly consistent. The purpose of the each scheme is summarised in Table 2 below, and Figure 2 shows the incentive rewards and penalties from 2005 to 2011.

Table 2: The gas SO financial incentive schemes

Scheme	Purpose
Residual balancing	Minimise the impact of its role in balancing the system
Greenhouse gas emissions (venting)	Minimise emissions due to venting of compressors
Demand forecasting	Minimise the error of NGG's day ahead demand forecasts.
Shrinkage	Minimise cost of purchasing gas and electricity for operating compressors, CV shrinkage and UAG
Data publication	Encourage timeliness & availability of published information
Operating margins (OM)	Minimise the cost of procuring operating margins requirements

Figure 2: Performance of the gas SO against the financial incentive schemes (2005 – 2012)³



3.9. In aggregate, the performance of the SO has been fairly consistent over the seven year period with its overall performance leading to net incentive payments of between £4m and £9m to the SO each year. The main driver of the payments to the SO has been the shrinkage incentive scheme which has hit its cap each year, except in 2008-9. In Section 5 we outline our initial proposals for the gas SO incentive schemes from 2013, including the changes that we are making to the shrinkage scheme.

³ Note that unaccounted for gas (UAG) is not shown as it has not generated an incentive payment or reward in any year this scheme was in place (from 2009/10 to 2011/12).



4. Electricity SO incentives

This section sets out an overview of our main proposals for the electricity SO. Following the RIIO framework, we look at outputs, costs and SO-TO interactions in turn. Supporting analysis relevant to the questions we ask can be found in Appendices two and three.

Electricity SO output incentives

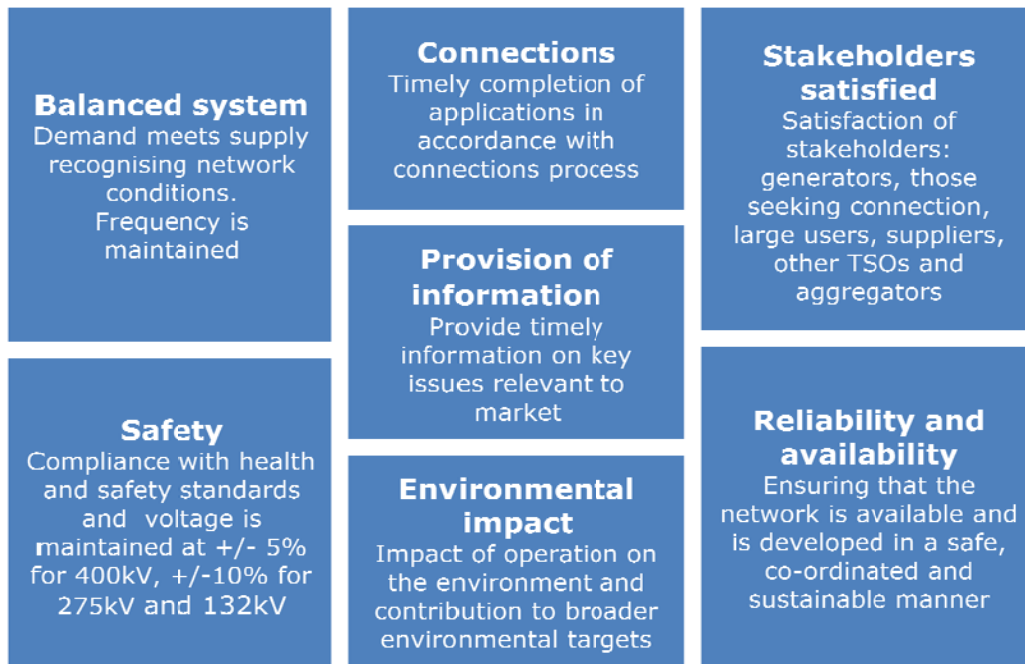
Question 1: In respect of transmission losses, do you agree with our proposal to put in place a reputational incentive and to remove the current financial incentive?

Question 2: Please provide your comments in respect of our proposals for an incentive on renewable forecasting. In particular:

- a. Do you agree that an incentive is appropriate?
- b. Which renewable output forecast would you like to be incentivised (5pm, 5am, 11am or 11pm)?
- c. Do you have a view on which error measure should be incentivised and whether the monthly target should be set on an annual or a seasonal basis?
- d. Do you agree with the proposed cap, floor and range of the incentive?
- e. Do you agree that the incentive should initially be set for 2 years?

4.1. As we set out in our January consultation document, we have considered what NGET is expected to deliver in respect of the seven output categories shown in Figure 3.

Figure 3: Electricity SO output categories





System Operator incentive schemes from 2013: initial proposals
Overview

4.2. We divided these seven broad categories into twelve separate areas and proposed implementing financial incentives for two of these categories and reputational incentives for five more. The remaining five categories we considered were adequately covered elsewhere in legislation or will be incentivised under the RIIO-T1 regime.

4.3. As Table 3 demonstrates, our views on the appropriate treatment of many of these output categories generally remain broadly the same. However, in three instances (broad environmental targets, reliability and availability, and stakeholder satisfaction) it has become apparent that it would be more efficient to implement a joint SO-TO approach.

4.4. The only major change from the January consultation for the output incentives is that we are no longer proposing to implement a financial incentive on transmission losses, for reasons that are explained further below.

Table 3: Electricity SO output incentives

Output	Initial proposals
Safety	
Work place safety – to design and operate its network to ensure the safety of the public and its employees	As set out in our January consultation, this is captured by HSE legislative requirements: no incentive scheme.
Correct system voltage – to ensure that voltage is maintained at $\pm 5\%$ for 400kV $\pm 10\%$ for 275kV and 132kV lines	As set out in our January consultation, this is captured by HSE legislative requirements: no incentive scheme.
Environmental impact	
Broad environmental targets – to ensure energy companies play a full role in the delivery of a sustainable energy sector	We will incorporate the electricity SO into the Environmental Discretionary Reward (EDR) scheme (rewards of up to £4m a year).
Transmission losses – to reduce transmission losses when procuring the services it needs to balance the system	Replace the current financial incentive with a reputational incentive.
Business carbon footprint – to reduce its business carbon footprint	SO impact captured in TO output in RIIO-T1: no incentive scheme.
Connections	
Timely connections process – to fulfil its obligations regarding the connections process under its licence and the Connection and Use of System Code (CUSC)	In our January consultation we set out our view that the financial output incentive under RIIO-T1 captures the SO, therefore we will not implement an incentive on connections.
Reliability and availability	
Management of processes and procedures – to play an important, proactive and innovative role	We have decided to progress this as part of the Network Access Policy (NAP) work being undertaken under RIIO-T1 rather than as part of the SO incentives.
Interactions with TO's, especially with respect to network investment – to develop a policy statement that demonstrates how ongoing interactions	We have decided to progress this as part of the Network Access Policy (NAP) work being undertaken under RIIO-T1 rather than as part of the SO incentives.



Output	Initial proposals
<i>between the SO and TOs (and TSOs) will occur</i>	
Stakeholders satisfied	
Stakeholder survey – to assess customer/stakeholder views of the SO's performance	We consider that the RIIO-T1 stakeholder survey financial incentive covers both SO and TO issues. Therefore, no additional incentive scheme in the SO regulatory framework.
Balanced system	
Demand meets supply – to balance electricity system demand and supply to ensure the security and quality of electricity supply across the GB Transmission System – to keep frequency within the required boundaries ($\pm 1\%$ 50Hz save in abnormal or exceptional circumstances)	We have decided not to proceed with introducing output incentives here and will instead monitor how these output measures develop over time as part of our broader approach to incentives discussed below.
Provision of information	
General information provision – to provide information to the market on energy issues including how the system is operating as well as more general information that could be useful to the sector	As there are already legal requirements for NGET to provide information we are not proposing to have a separate output incentive scheme. In the event of non compliance we have a number of actions available to us and views on the information provided will be captured through the stakeholder survey.
Information on renewable generation – to provide timely information to the market about the level of renewable generation (principally wind generation) expected over the short and medium	Financial incentive based on monthly targets, with cap and floor of £250k. Considering whether output measure should be mean average error or root mean square error and also whether target for each month should be fixed on an annual or seasonal basis.

4.5. In addition to the outputs proposed in the January consultation, we are now proposing a further output on **innovation leading to environmental benefits and security of supply**. Our proposal is that the SO should be incorporated into the Network Innovation Competitions (NICs) where funding for the best innovation projects will be available.

4.6. In our January consultation, we also discussed the issue of SO-SO interactions and the potential benefits associated with National Grid, as both electricity and gas SO, taking into account the interactions between the activities of both SOs when making decisions. However, we need to consider further the implications of SO-SO information sharing so we will not make any proposals at this stage on SO-SO interactions from April 2013.

Transmission losses

4.7. Transmission losses are the energy that is lost as electricity flows across the system. Annual transmission losses have historically been around two per cent of demand. We are of the opinion that the changing mix of plant types on the GB system will make it increasingly difficult for the SO to forecast or control the level of losses. For example, the increasing capacity of wind plants in Scotland is likely to



increase losses and it would not be environmentally beneficial for the SO to constrain these plants off (in favour, for example, of thermal generation located in the South) to reduce the volume of losses. In addition we recognise that the SO can only manage the losses associated with a small proportion of the total volume of energy (approximately 3% of electricity generated goes through the Balancing Mechanism).

4.8. On this basis, we propose removing the current financial incentive. We considered whether it would be possible to design a scheme that focussed on those elements of losses that the SO can control (and the SO included a proposal in its business plans that aimed to do this). However, we are of the view that any such proposal would be complex, opaque, and unlikely to yield material results.

4.9. Nevertheless, we recognise the significance of transmission losses and that they are likely to increase as more remote generation connects to the network. Therefore, while we are proposing to remove the financial incentive, we want the SO and stakeholders to continue to have a keen interest in transmission losses. So we are proposing to extend the RIIO-T1 reputational incentive on losses to also cover the SO. Under this proposal, NGET would publish its strategy for transmission losses and report to stakeholders annually on its progress in implementing its strategy. It would also include an estimate of the impact this has had on transmission losses in its transmission area.

Information on renewable generation

4.10. In our January consultation we set out that we consider that the SO is uniquely well placed to provide information to the market about the likely level of renewable generation and proposed that an output incentive on the accuracy of renewable generation forecasts should be introduced. Accurate forecasting of renewable generation will become increasingly important as the volume of intermittent renewable generation increases. Accurate forecasts will enable stakeholders, if they choose to rely on NGET's forecasts, to balance their positions more accurately. They should also enable NGET to manage the costs of operating reserve more efficiently.

4.11. Our proposal is to introduce a renewables forecasting incentive broadly along the lines proposed by NGET in its business plans. The incentive will be based on the minimising the average error in its forecasts over the course of a month, and we propose that the SO will have a symmetrical monthly incentive calculated on a sliding scale from a reward of £250k for a zero error to a maximum penalty of £250k when the error that is twice the target error. Appendix 2 sets out several areas where we would welcome the views of respondents on the detail of this proposal. As this is a new scheme, our proposal is for the scheme parameters to be set initially for a two year period.

Electricity SO cost incentives

Question 3: In respect of the incentive on energy balancing and constraint costs, do you agree that direct financial incentive should be removed?

Question 4: Do you agree that we should put in place a licence condition to



enable us to disallow costs incurred by NGET if they are uneconomic or inefficient?

Question 5: Please provide your comments in respect of our proposals for a discretionary reward mechanism. In particular:

- a. Do you consider that the proposed process for agreeing to a reward is appropriate?
- b. Who should be the members of the panel that decides upon reward requests?
- c. Is the size of the potential reward appropriate?
- d. Are the examples of behaviours that might lead to a reward being made appropriate?

Question 6: Do you consider that a cost incentive on black start should be retained? Do you consider that the proposed parameters for a black start scheme are appropriate?

Question 7: What are your views on NGET's proposals for commercial contracts with non-NGET TOs to incentivise them in respect of constraint costs caused by changes to their output plans?

4.12. As described in the preceding section, the divergence between target and outturn electricity SO balancing costs has increased significantly since 2008. It is also clear that the fundamental review that we undertook and NGET's efforts to introduce more robust modelling techniques has not solved this problem. Our view is that the problem has primarily been caused by the changing nature of the market, as developments in the mix and location of generating plants (eg the growth of wind farms in Scotland) have moved faster than transmission infrastructure changes and the market design has not fundamentally changed to accommodate these developments.

4.13. The electricity market will undergo further significant changes over the course of the eight year incentive scheme period and this means that modelling balancing costs is likely to become even more challenging. The level of intermittent generation on the system is set to increase substantially and this may necessitate increased requirements for reserve and, possibly, other balancing services. European initiatives, such as the implementation of the Electricity Target Model⁴, may also impact on the way in which the SO balances the system as might other work that we are undertaking, such as the electricity cash-out Significant Code Review⁵. NGET's proposals contain provisions for regular fundamental reviews to the models in addition to annual updates to parameters.

4.14. For all these reasons, we remain to be convinced that any modelling approach will provide a robust method for setting incentive scheme targets over the next few years. The models are likely always be "playing catch up" with the market and are likely to become increasingly complex. Stakeholders have expressed concerns that the models used by NGET to forecast its energy and constraint target costs are already too complex and opaque and that this makes it difficult for them to comment meaningfully not only on proposed schemes but also on NGET's performance against the schemes.

⁴ <http://www.ofgem.gov.uk/Europe/Documents1/EU%20Target%20Model%20open%20letter.pdf>

⁵ <http://www.ofgem.gov.uk/Markets/WhlMkts/CompandEff/CashoutRev/Documents1/electricity-cash-out-SCR.pdf>



4.15. Where an incentive target is not realistic or robust the power of that incentive to promote the “right” behaviours is reduced and perverse behavioural incentives can arise. For example, where there is a possibility of the SO making windfall gains and losses (through events that are beyond its control) its incentive to take actions to improve outputs or reduce costs is reduced. Where targets are missed by a large margin, the focus of the SO’s efforts may naturally turn to resetting the target rather than on behaviours to improve performance against the target. Either way, once the cap or floor is significantly breached, the incentive becomes less effective. As explained in section 3, this has been the case in the last four years in a row. Where targets are adjusted regularly, particularly if they are adjusted retrospectively, the power of the incentive is undermined as the target is less credible.

4.16. More fundamentally, we have been concerned for several years now that short term schemes are not encouraging the right sorts of behaviours and that the only way forward for the electricity cost incentive is to have a longer term scheme. With the current modelling this is clearly not credible. We propose, therefore, to remove the direct incentive on balancing services costs. However, as explained further below, we are of the view that NGET, as SO, should face broader incentives to play its full role in creating a sustainable decarbonised market.

4.17. We recognise that NGET’s business plans include proposals for a balancing cost scheme and that it is continuing to work on improving its models. However, even if the new models were to overcome the problems listed above, which we consider doubtful, they would not be available for scrutiny and validation until the end of August 2012. Given the performance of the current set of models, whose performance was initially relatively good but has since declined, we consider it essential that there is an extensive period of testing before any new models are used to set a cost target. Consequently, even if we were to propose a shorter term balancing services cost incentive, it is our view that it would not be plausible to introduce new cost incentives from April 2013.

Balancing services costs (energy costs and constraint costs): A broader approach to incentives

4.18. We propose moving away from short-term incentives based on detailed modelling of balancing costs to a broader incentive approach, designed to encourage more innovative behaviour, which recognises the increasing challenges that are likely to be associated with balancing the system. Without a mechanistic incentive on balancing costs, in the first instance we will rely on:

- a) Clear obligations on the SO and **monitoring** its performance. Therefore, we propose to clarify and extend the current licence conditions to leave no doubt that actions to reduce balancing costs are part of the SO’s “business as usual”. We will also increase our scrutiny of balancing costs and work to enhance the transparency of information available to stakeholders.

4.19. If our monitoring of SO costs shows problems or successes, we want to be able act on these findings:

- b) Consequently, we propose to introduce licence conditions that would enable us (i) to **disallow costs** that the SO has incurred if it can be demonstrated that the SO has taken inefficient actions and (ii) to award discretionary payments to the SO if it is “making a difference” in the way in which it operates the system. For example, under such a **discretionary reward** scheme, the SO might be able to retain say 25% of any measurable net benefit to consumers resulting from the actions it takes that go well beyond “business as usual”. By providing clear upsides and downsides for actions that fail to meet, or go well beyond, “business as usual” we intend to focus the SO on the right behaviours in the context of the longer term challenges.

4.20. Alongside this approach of monitoring, disallowing costs, and discretionary rewards, we are proposing:

- c) **Financial incentives** on those SO services which we believe can be effectively incentivised. In addition to the output related incentives on renewable forecasting and, via RIIO-T1, on innovation, environmental performance and stakeholder satisfaction, this may include the development of SO-TO interactions (as part of the RIIO-T1 Network Access Plans) and possibly black start.

4.21. Separately, we will press ahead with our ongoing work looking at efficient balancing and system operation in the context of the implementation of the European Electricity Target Model in GB and the review of cash-out arrangements. Overall, along with increased investment in transmission provided for in the RIIO-T1 proposals, we consider this is the best way to meet long-term challenges and seek step changes in the level of balancing costs and the approach that the SO takes in managing them. Appendix 3 has more detail on how our proposals on monitoring, enforcement and the discretionary rewards could work. We note here that internally, we will also be reviewing why the improvements to the methodology and the models underpinning the incentive scheme have not worked. This leaves open the option of re-introducing financial incentives on balancing costs in the future.

Black start

4.22. If the electricity system experiences a full or partial shut-down, isolated power stations that have black start capability (an auxiliary generating plant located on-site) are started individually and gradually connected to each other to form an interconnected system again. Black start capability is seen as important for security of supply. NGET is forecasting that the costs of ensuring sufficient black start capability will increase by approximately a factor of four over the next eight years due to the need to contract with new service providers as some of the plants currently providing this service are decommissioned.

4.23. In view of the likely trend towards increasing black start costs, we are considering continuing with a financial incentive on black start costs, broadly along the lines proposed by NGET in its business plans though with some important differences that are set out in Appendix 3. We would set sharing factors, caps and floors for this scheme. On the basis of NGET’s historic black start performance, we



would propose that the cap and floor should be +/- 10% of each year's target costs and that the sharing factors should be 25%.

4.24. However, we are also mindful of the importance for system security of black start provisions and the difficulty of assessing reasonable cost targets (and the risk of perversely rewarding the SO for not having taken longer term actions already). For these reasons, we are considering whether it would be more appropriate to remove the cost incentive and rely instead on monitoring NGET's procurement process as part of the broader monitoring approach outlined above. We would welcome views on which approach is more appropriate.

SO-TO interactions

4.25. In our January consultation we indicated that we expected the SO to take account of SO-TO interactions when making decisions about output delivery and that it may improve overall efficiency if there is a provision for the SO to pay the Scottish TOs to incentivise them to change their outage plans to deliver overall cost savings to customers.

4.26. NGET is proposing an adjustment to the way in which its incentivised balancing costs are currently calculated to reduce very significantly its exposure to changes in constraint costs that are caused by alterations in network outages on grids that are not owned by National Grid. NGET also suggested that it should enter into commercial arrangements with non-NGET TOs that would result in payments being made to the TO where it adjusted its network outages in a way that reduced the constraint costs. Conversely, where changes in network outages lead to increased constraint costs, the TO would make payments to the SO.

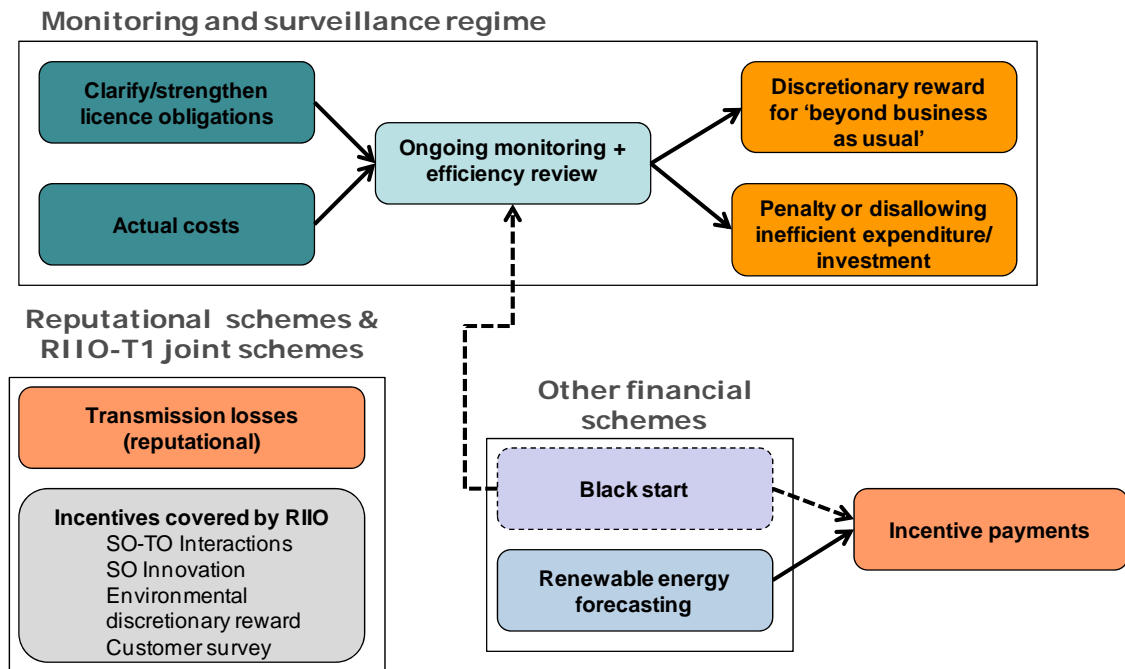
4.27. We broadly support NGET's proposals to align the interests of Scottish Power Transmission Limited (SPTL) and Scottish Hydro Electric Transmission Limited (SHETL) with the SO in seeking to reduce costs. We also consider that these proposals are equally important if (as we propose) there is no mechanistic incentive on balancing costs as improvements in this area are a necessary part of efficient operation. However, the proposals that NGET has made are under-developed (including insufficient dialogue with the TOs before submitting the plan) and involve significant overlap with broader work that is being undertaken in relation to network availability (the Network Access Policy (NAP)) under the RIIO-T1 price control. For these reasons, we have decided to progress the SO-TO interaction proposals as part of the NAP work being undertaken under RIIO-T1 rather than as part of the SO incentives.

Summary of electricity SO proposals

4.28. Our proposals for the electricity SO are summarised in Figure 4 below. Note that this regime would operate within a context where we will also be considering more fundamental reform through the implementation of the European Electricity Target Model in GB and the review of cash-out arrangements.



Figure 4: Overview of proposed electricity SO regime from 2013/14



5. Gas SO incentives

This section sets out an overview of our main proposals for the gas SO. Following the RIIO framework, we look at output incentives and cost incentives in turn. Supporting analysis relevant to the questions we ask can be found in Appendices four and five.

Gas SO Output incentives

Question 8: In respect of an incentive on greenhouse gas emissions, is your preference for Option 1 (penalty only) or Option 2 (upside and downside payment) and why?

Question 9: Please provide your comments in respect of our proposals for a residual balancing incentive. In particular, do you agree that by fixing the targets for the eight year period this will provide NGG with an incentive continuously to improve its performance in this area?

Question 10: Do you agree that we should continue to put in place a reputational incentive on NGG in respect of investigating the drivers of UAG? Do you support the proposed industry workgroup to assist the investigation of the drivers of UAG?

Question 11: Please provide your comments in respect of our proposals for demand forecasting incentives. In particular:

- a. Do you agree that by fixing the targets for the eight year period in respect of the D-1 forecast this will provide an NGG with an incentive continuously to improve its performance in this area?
- b. Do you agree with our proposal to amend the calculation of the error target, including increasing the weighting for days of higher demand?
- c. Do you agree with our proposals for the D-5 to D-2 forecast incentive?
- d. Do you agree that the improvement in the NDM forecast should be taken forward by the DNs?

Question 12: Do you consider that our proposals in respect of maintenance could address the concerns that you have in respect of NGG's behaviour in this area? Are our proposals appropriate and likely to be effective?

5.1. As we set out in our January consultation document, we intended to incentivise National Grid Gas (NGG) in respect of the seven output categories shown in Figure 5 below.



Figure 5: Gas SO output categories



5.2. In general our views on the type (financial or reputational), length and structure of each output incentive remain the same as those that we set out in the January consultation, as can be seen from Table 4 below. However, our thinking in respect of incentives to reduce NGG’s direct emissions from venting gas and to improve demand forecasting has developed since the January consultation.

5.3. On the **direct emissions output incentive**, we propose that over the longer term NGG should take full responsibility for the environmental costs of the gas it vents (“polluter pays” principle). Accordingly, we have considered two structural options for a greenhouse gas emissions incentive scheme, both based on a methane emissions threshold. The current approach allows a “deadband” range around the threshold, penalises NGG if its emissions exceed the range, and rewards NGG if its emissions are below the range, at the non-traded sector CO₂e price. Particularly coupled with the fact that NGG expects higher emissions in 2012/13, we are concerned this does not give adequate incentives. Structurally one option (Option 1) would be a one-way incentive, which would penalise NGG for emissions above a threshold but not give a financial reward for over-achieving. The other option (Option 2) is retain the two-way incentive but to remove the deadband range. NGG was due to provide more detailed information on methane emissions in its Scheme of Work but this work is not now expected to be completed in time for the information to be included in an incentive for 2013. The existing threshold covers venting from compressors and is set at 3007tCO₂.

5.4. We note that government projections for methane emissions from the energy sector project a halving of overall energy sector methane emissions from



2010 to 2030 (from about 8000 to 4000ktCO₂e), implying a substantially more rapid reduction of methane than CO₂ *even in the absence of specific incentives for controlling methane* from the energy sector. We also note that methane has disproportionately greater short term impact; that there are potentially cheaper options for controlling or capturing methane than CO₂; and that we have allowed funding for capital investment under RIIO-T1 some of which may also contribute to methane reductions. We therefore propose that the threshold for charging NGG for methane venting starts with a linear reduction of 5% per year from the existing threshold. Once we receive information from the Scheme of Work, we may revise the 5% annual reduction figure and the scope of emission sources included (and corresponding threshold) may also be adjusted to include the results of NGG’s investigation into the emissions produced from venting gas from sources other than compressors. Moreover, given the inadequacy of information at present, we believe it would be inappropriate for NGG to have a potential financial reward. Accordingly, we are minded to implement option 1 (one-way incentive) and introduce a short-term threshold based on the current level (3007 tonnes) minus the 5% per year reduction factor; we may subsequently review the threshold and implementation options incorporating the results from NGG’s investigation.

5.5. For **demand forecasting**, we have taken account of stakeholders’ desire for NGG’s longer term (D-2 to D-5) forecasts to be more accurate and are proposing to introduce a new financial incentive to improve these forecasts. At the same time, we are proposing to improve the D-1 forecast incentive by changing the way the average error is calculated.

5.6. In addition, we are proposing two new output incentives relating to the **number of maintenance days** and **changes in maintenance days**. These new incentives are a response to stakeholders’ requests for incentives in these areas.

5.7. For all the existing output incentives, we are proposing to put in place schemes whose parameters will be fixed in advance for eight years. However, we propose that the Authority should have the ability to reopen a scheme should it appear no longer fit for purpose after four years. For the new output incentives (D-2 to D-5 forecasts and the maintenance incentives), we are proposing that the initial schemes should only last two years. This will enable us to review how well the new incentives have worked, and adjust them as appropriate in the light of experience. We believe that these decisions provide an appropriate balance between regulatory certainty and capping NGG’s exposure to risks.

Table 4: Gas SO output incentives

Output	Initial Proposals
Safety	
Work place safety <i>- to operate its network to ensure the safety of the public and its employees</i>	Covered by legal requirements and captured by RIIO-T1 outputs – no SO scheme.



System Operator incentive schemes from 2013: initial proposals
Overview

Output	Initial Proposals
Meet Operating Margins requirements <i>- to ensure that Operating Margins are purchased to meet Safety Case requirements</i> <i>- to work with potential new providers of OM in order to facilitate additional providers</i>	Meeting Safety Case requirements captured by wider HSE legal requirements – no output based financial SO scheme. Update existing licence requirement to promote competition (Special Condition C25), including transparent reporting requirements (reputational incentive in SO regulatory framework set for eight years).
Environmental impact	
Broad environmental output <i>- to ensure that energy companies play a full role in the delivery of a sustainable energy sector</i>	There are no clear aspects identified where the gas SO could be expected to make a contribution at this stage. No additional SO scheme.
Reduction in venting emissions <i>- to consider how it operates its system to reduce emissions, also potential to introduce alternatives to venting</i>	Introduce financial incentive. Target adjusted each year by 5%. Target to incorporate results from Scheme of Work (Special Condition C28) when available then. Considering two possible options but minded to implement option 1: <ul style="list-style-type: none"> • Option 1: Asymmetric scheme (only penalties) • Option 2: Symmetric structure (rewards and penalties). No deadband.
Connections	
Ensure efficient and timely connections <i>- to fulfil its obligations regarding a connections process that needs to be put in place</i>	Covered by implementation of UNC 373. No separate SO scheme.
Reliability and availability	
Make capacity available at entry and exit points to meet customer requirements <i>- to ensure capacity is made available as required and in the most efficient way</i> <i>- to have in place and adhere to a methodology statement that details how it chooses between the different options (eg buy-back, invest) it has in respect of making capacity available</i>	Under RIIO-T1, NGG to produce a methodology statement on how it makes capacity available. No further incentive.
Stakeholders satisfied	
Stakeholder survey <i>- to ensure that NGG's stakeholder survey includes questions relating to NGG's role as system operator</i>	Financial incentive in RIIO-T1 will cover both SO and TO roles. No further incentive.
Balanced system	
Supply = demand <i>- to ensure that supply and demand are equal on a daily basis subject to pressure and linepack requirements</i>	No SO regulatory output scheme.
Minimise change in linepack <i>- to ensure that the change between each end</i>	Financial incentive for eight years. No change to current scheme parameters.



System Operator incentive schemes from 2013: initial proposals
Overview

Output	Initial Proposals
<i>of day linepack is kept to a minimum</i>	
Minimise impact on On the Day Commodity Market <i>- to ensure that when NGG enters the OCM it minimises its impact on the market by trading close to the market price</i>	Financial incentive for eight years. No change to current scheme parameters, (duration of scheme to be eight years).
Unaccounted for gas <i>- to continue to explore the drivers of Unaccounted for Gas</i> <i>- should current ongoing work to understand the drivers of UAG highlight specific outputs for the gas SO</i>	Reputational incentive for eight years to investigate drivers and report on volumes of UAG. Update existing Special Condition C29 and extend condition to require NGG to promote wider industry involvement in investigating causes of UAG.
Provision of information	
Availability and timeliness of information on website <i>- to ensure that the SO publishes information that enables market participants to operate in the gas market</i>	Remove current financial incentive and introduce a reputational incentive for eight years.
Accuracy of demand forecasts <i>- to ensure that the demand forecasts that NGG publishes are as accurate as possible</i>	D-1 13:00 forecast: Financial incentive set for eight years. Modify current performance measure to give more weight to days when demand is high. Other parameters remain the same as current incentive. New financial incentive relating to overall accuracy of D-2 to D-5 forecasts ie a single bundled incentive across all four forecasts. Incentive initially set for two years. NDM demand forecast: No SO output incentive.
Publication of forward looking market information <i>- to publish information to the market that assists participants with understanding future developments</i> <i>- to publish statements that assist market participants to understand how NGG as SO undertakes its role</i> <i>- to ensure that actions undertaken by the SO or TO that affect the other party are transparent</i>	Reputational incentive to publish information.
Maintenance	
<i>Minimise number of changes to agreed maintenance plans, whilst carrying out an efficient level of maintenance.</i>	Financial incentive on number of maintenance days and financial incentive on minimising NGG instigated changes to Maintenance Plan. Both incentives to be set for two years.

5.8. In its Stakeholder Engagement consultation, NGG raised the possibility of introducing an incentive for it to provide enhanced services for NTS users. NGG did not propose an incentive in this area in its business plans and we do not consider



that it would be appropriate to introduce such an incentive until it is clearer what types of services stakeholders would value.

5.9. We also note that, in its March 2012 RIIO-T1 submission, NGG submitted proposals on how it intended to use innovation funding to drive improvements in its business. It considers that this funding should also be available to the SO and we concur with this view.

Gas SO Cost incentives

Question 13: In respect of Operating Margins, do you agree with our proposal to put in place a reputational incentive and to remove the current cost incentive?

Question 14: Please provide your comments in respect of our proposals for a shrinkage incentive, in particular:

- a. Do you agree that it is appropriate for NGG to have in place a volume methodology statement?
- b. Do you agree that the proposed changes to the reference prices are appropriate?
- c. Do you agree with the proposed sharing factor? Do you agree with increasing the cap and floor of the incentive?

5.10. NGG is currently subject to two cost incentives – one on shrinkage costs and the other on operating margins costs. In our January consultation, we also raised the possibility that it should be subject to a residual balancing cost incentive (either in place of or in addition to the residual balancing output incentives). Our proposals for these three incentives are summarised in Table 5 below.

5.11. We have decided not to introduce a residual balancing cost incentive at present. Most respondents to the January consultation were of the view that there was no need for such an incentive since the current output schemes worked well and were understood by stakeholders. We concur with this view but will revisit the possibility in the future should within day gas flow volatility increase significantly.

5.12. Whilst we are proposing that the format of the shrinkage cost incentive remains broadly comparable to the current scheme, we are proposing a number of adjustments largely based on NGG's business plan. There are three main amendments that we consider would improve the incentive. First, NGG will be required to produce a methodology statement that explains how the target shrinkage volumes for each year will be determined. This will ensure that stakeholders understand how the targets are arrived at whilst at the same time providing sufficient flexibility for the target volume to reflect changing market conditions over the eight year period. Second, we are proposing to change the way in which the reference price for the quarterly baseline volume is calculated so that it takes into account forward prices up to the month prior to the start of the quarter. Third, we propose that the short-term adjustment to the baseline volume should be priced at a short-term (ie within month) reference price rather than being derived from a month-ahead price adjusted by an uplift factor.

5.13. As regards the operating margins cost incentive, taking into account respondents' views to the January consultation and NGG's business plan assessment,



we have come to the view that it may not be appropriate to continue with a cost incentive at present but instead to rely on the operating margins output incentive discussed above. There are a number of reasons for this decision, which are set out in Appendix 5.

Table 5: Gas SO cost incentives

Scheme	Scheme length	Cost target methodology	Sharing factor
Shrinkage cost (bundled) ⁶	Eight years	<p>NGG to put in place a methodology statement to forecast baseline shrinkage volumes. Methodology subject to annual audit requirement.</p> <p>Reference prices better aligned with NGG's energy purchases:</p> <ul style="list-style-type: none"> • Forward prices: nine month rolling average • Short term prices: shorter than month ahead (eg week ahead) • No swing uplift. 	<p>45% Cap and floor to be determined after methodology statement is consulted</p>
Operating margins cost	Reputational incentive		
Residual Balancing cost	No scheme (see table 4 for output incentive)		

⁶ The shrinkage cost scheme will, as now, bundle Compressor Fuel Use costs, Calorific Value Shrinkage costs and Unaccounted for Gas costs.



6. Uncertainty mechanisms and risk premium

For both the gas and electricity SOs we are proposing uncertainty mechanisms. This section also sets out our proposals on the risk premium that National Grid included in its business plans.

Question 15: Do you agree with our proposals for uncertainty mechanisms and on not including a risk premium?

Uncertainty mechanisms

6.1. As outlined in our January consultation, we consider that it is appropriate to introduce a general uncertainty mechanism that will permit Ofgem to reopen the regulatory framework in certain extreme circumstances. This general uncertainty mechanism is particularly important since we are increasing the length of some of the schemes and this inevitably increases the risk that a scheme will become unfit for purpose at some point in its period of application or that legislative change or other one-off events will significantly change the role of the SO.

6.2. There are two broad sets of circumstances that, we propose, could lead us to use the uncertainty mechanism:

- a) Firstly, where expected or unexpected 'events' that have a significant impact on the role of the SO occur. For example, the outcome of Electricity Market Reform or the outcome of our gas security of supply review could have significant implications for the role of the SO. Where the role of the SO is likely to change significantly, we envisage a review of SO regulation triggered by the uncertainty mechanism which would involve looking at all the schemes in the round. We will be able to specify in our final proposals and therefore in the licence drafting some of the events that we expect would trigger the uncertainty mechanism.
- a) Secondly, individual schemes, or sets of schemes, may become unfit for purpose. For example, an output may become irrelevant or a scheme may hit its cap or floor and appear likely to continue doing so in future years rendering the incentive for 'right' behaviours ineffective.

6.3. Our proposed mechanism would operate in a different way to the current income adjusting event (IAE) uncertainty mechanism, which we propose to remove. We consider that the current IAE mechanism can be triggered in too many circumstances, potentially undermining the credibility of the targets and the strength of the incentives. We therefore propose that the new uncertainty mechanism can only be triggered by the Authority. We consider that this will mean that there is more certainty that it would be triggered where National Grid is receiving payments under its SO incentive schemes as well as when National Grid is making losses under the



schemes. This will ensure that individual incentive schemes are not continually being reopened at varying times over the period. We also propose that National Grid can apply to the Authority to reopen a scheme or set of schemes under the uncertainty mechanism. The decision would rest with the Authority and would therefore be open to Judicial Review. Where the uncertainty mechanism is used, any changes to schemes by way of a direction as a result of using the mechanism would be subject to consultation and would not be retrospective.

Risk premium

6.4. In its Business Plans, National Grid set out its view that it considers that ex ante risk premiums (£3.3m a year for the gas SO and £7.7m a year for the electricity SO) are required to cover the residual risk within its proposals.

6.5. Our view is that the schemes that we are proposing, including the sharing factors, caps, floors and uncertainty mechanisms adequately reflect the risks to National Grid. In addition, our initial proposals adequately manage the financial scope of the schemes. Therefore, we consider that the risks associated with the proposals are not significantly different to those the SOs face under the current schemes and we are not proposing that an additional risk premium is included as part of the incentive framework.



7. Appendices

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Appendix 1 – Consultation Response and Questions

1.1. Ofgem would like to hear the views of interested parties in relation to any of the issues set out in this document. We would especially welcome responses to the specific questions which we have set out at the beginning of each section heading and which are replicated below.

1.2. Responses should be received by **21 September 2012** and should be sent to soincentive@ofgem.gov.uk for the attention of:

Giuseppina Squicciarini
Head of Regulatory Economics
Ofgem
9 Millbank
London
SW1P 3GE

1.3. Unless marked confidential, all responses will be published by placing them in Ofgem's library and on its website www.ofgem.gov.uk. Respondents may request that their response is kept confidential. Ofgem shall respect this request, subject to any obligations to disclose information, for example, under the Freedom of Information Act 2000 or the Environmental Information Regulations 2004.

1.4. Respondents who wish to have their responses remain confidential should clearly mark the document/s to that effect and include the reasons for confidentiality. It would be helpful if responses could be submitted both electronically and in writing. Respondents are asked to put any confidential material in the appendices to their responses.

1.5. Any questions on this document should, in the first instance, be directed to Giuseppina Squicciarini, Head of Regulatory Economics, European Wholesale (Ph: 020 7901 7366), email: giuseppina.squicciarini@ofgem.gov.uk or to David O'Neill, (Ph: 020 7901 3874), email: david.o'neill@ofgem.gov.uk.

SECTION: Four

Question 1: In respect of transmission losses, do you agree with our proposal to put in place a reputational incentive and to remove the current financial incentive?

Question 2: Please provide your comments in respect of our proposals for an incentive on renewable forecasting. In particular:

- a. Do you agree that an incentive is appropriate?
- b. Which renewable output forecast would you like to be incentivised (5pm, 5am, 11am or 11pm)?
- c. Do you have a view on which error measure should be incentivised and whether the monthly target should be set on an annual or a seasonal basis?
- d. Do you agree with the proposed cap, floor and range of the incentive?

e. Do you agree that the incentive should initially be set for 2 years?

Question 3: In respect of the incentive on energy balancing and constraint costs, do you agree that direct financial incentive should be removed?

Question 4: Do you agree that we should put in place a licence condition to enable us to disallow costs incurred by NGET if they are uneconomic or inefficient?

Question 5: Please provide your comments in respect of our proposals for a discretionary reward mechanism. In particular:

- a. Do you consider that the proposed process for agreeing to a reward is appropriate?
- b. Who should be the members of the panel that decides upon reward requests?
- c. Is the size of the potential reward appropriate?
- d. Are the examples of behaviours that might lead to a reward being made appropriate?

Question 6: Do you consider that a cost incentive on black start should be retained? Do you consider that the proposed parameters for a black start scheme are appropriate?

Question 7: What are your views on NGET's proposals for commercial contracts with non-NGET TOs to incentivise them in respect of constraint costs caused by changes to their output plans?

SECTION: Five

Question 8: In respect of an incentive on greenhouse gas emissions, is your preference for Option 1 (penalty only) or Option 2 (upside and downside payment) and why?

Question 9: Please provide your comments in respect of our proposals for a residual balancing incentive. In particular, do you agree that by fixing the targets for the eight year period this will provide NGG with an incentive continuously to improve its performance in this area?

Question 10: Do you agree that we should continue to put in place a reputational incentive on NGG in respect of investigating the drivers of UAG? Do you support the proposed industry workgroup to assist the investigation of the drivers of UAG?

Question 11: Please provide your comments in respect of our proposals for demand forecasting incentives. In particular:

- a. Do you agree that by fixing the targets for the eight year period in respect of the D-1 forecast this will provide an NGG with an incentive continuously to improve its performance in this area?
- b. Do you agree with our proposal to amend the calculation of the error target, including increasing the weighting for days of higher demand?
- c. Do you agree with our proposals for the D-5 to D-2 forecast incentive?
- d. Do you agree that the improvement in the NDM forecast should be taken forward by the DNS?

Question 12: Do you consider that our proposals in respect of maintenance could address the concerns that you have in respect of NGG's behaviour in this area? Are our proposals appropriate and likely to be effective?

Question 13: In respect of Operating Margins, do you agree with our proposal to put in place a reputational incentive and to remove the current cost incentive?

Question 14: Please provide your comments in respect of our proposals for a shrinkage incentive, in particular:

- a. Do you agree that it is appropriate for NGG to have in place a volume methodology statement?
- b. Do you agree that the proposed changes to the reference prices are appropriate?



- c. Do you agree with the proposed sharing factor? Do you agree with increasing the cap and floor of the incentive?

SECTION: Six

Question 15: Do you agree with our proposals for uncertainty mechanisms and on not including a risk premium?



Appendix 2 – Electricity outputs and output incentives

See Supplementary Appendices Document



Appendix 3 – Electricity cost incentives

See Supplementary Appendices Document



Appendix 4 – Gas outputs and output incentives

See Supplementary Appendices Document



Appendix 5 – Gas Cost Incentives

See Supplementary Appendices Document



Appendix 6 – Glossary

A

Ancillary Services

Mandatory, necessary or commercial services used by the electricity System Operator to manage the system and to meet their licence obligations.

The Authority/Ofgem/GEMA

Ofgem is the Office of Gas and Electricity Markets, which supports the Gas and Electricity Markets Authority (GEMA), the body established by Section 1 of the Utilities Act 2000 to regulate the gas and electricity markets in Great Britain.

B

Balancing and Settlement Code (BSC)

Sets out the rules for governing the operation of the Balancing Mechanism and the Imbalance Settlement process and also sets out the relationships and responsibilities of all electricity market participants.

Balancing charges

Charges that NTS users pay for differences between their inputs and offtakes from the NTS and for differences between its nominated and delivered quantities.

Balancing Mechanism (BM)

The mechanism by which the electricity System Operator procures commercial services (Balancing Services) from generators and suppliers post gate closure, in accordance with the relevant provisions of the Balancing and Settlement Code (BSC) and the Grid Code.

Balancing Services

The services that the electricity System Operator needs to procure in order to balance the transmission system. Balancing services include ancillary services.

Balancing Services Incentive Scheme (BSIS)

A scheme that has been applied to the SO to incentivise efficient balancing of the transmission network.

Balancing Services Use of System charges (BSUoS)

The half-hourly charge, levied by the electricity System Operator on users of the transmission system, in order to recover the costs of operating the transmission system and procuring and utilising Balancing Services.



Black Start

If the electricity system experiences a full or partial shut down, isolated power stations that have black start capability (an auxiliary generating plant located on-site) are started individually and gradually connected to each other to form an interconnected system again.

C

Cap

The maximum incentive payment the SO is permitted to receive as part of an incentive scheme (this may also be subject to a 'sharing factor').

Capacity (gas)

The amount of natural gas that can be produced, transported, stored, distributed or utilised in a given period of time under network design conditions.

Capital expenditure (capex)

Expenditure on investment in long lived transmission assets, such as gas pipelines or electricity overhead lines.

Carbon footprint

Total amount of greenhouse gas emission caused directly and indirectly by a business or activity.

Connect and Manage

Under this regime generators can connect to the transmission network in advance of all the necessary upgrades and reinforcements to the wider transmission system being put in place.

Consumer

In considering consumers in the regulatory framework we consider users of network services (for example, generators, shippers) as well as domestic and business end consumers, and their representatives.

Compressor Station

An installation on the National Transmission System (NTS) that uses gas turbine or electricity driven compressors to boost pressures in the pipeline system; it is used to increase transmission capacity and move gas through the system.

Constraints (also known as congestion)

A constraint occurs when the capacity of transmission assets is exceeded so that not all of the required generation can be transmitted to other parts of the network, or an area of demand cannot be supplied with all of the required generation.



Connection and Use of System Code (CUSC)

Constitutes the contractual framework for connection to, and use of, National Grid's high voltage electricity transmission system.

Calorific Value Shrinkage (CV Shrinkage)

The volume of the energy which cannot be billed due to calorific value capping under application of the Gas (Calculation of Thermal Energy) Regulations 1996 (amended in 1997). Calorific value capping creates a shortfall between the amount of energy delivered and the energy that customers are charged for.

D

Demand side response

The reduction of customer energy usage at times of peak usage in order to help system reliability, to reflect market conditions and pricing, or to support infrastructure optimisation or deferral of additional infrastructure.

E

Ex Ante / Ex Post Inputs

Ex ante inputs to National Grid's models are those whose values are set prior to the start of the scheme and are not updated as the scheme progresses (except under specific agreed circumstances). Ex post inputs are collected on a monthly basis using outturn data. Ex ante and ex post data are combined with the agreed models to determine the level of costs against which National Grid should be incentivised.

Energy Imbalance

Energy imbalance costs are those incurred by National Grid to correct for differences between the generation supplied by the market and the demand on the system (see also Market Length).

F

Financeability

Financial models are used to determine whether the regulated energy network is capable of financing its necessary activities and earning a return on its regulated asset value (RAV) under the proposed price control. This financeability is assessed using a range of different financial ratios.

Floor

The maximum loss the SO can make as part of an incentive scheme (this may also be subject to a 'sharing factor').

Frequency Response

The electricity SO has a statutory obligation to maintain system frequency between +/- 1% of 50 hertz. The immediate second-by-second balancing to meet this



requirement is provided by continuously modulating output through the procurement and utilization of mandatory and commercial frequency response.

G

Gas Transporter (GT)

Formerly Public Gas Transporter (PGT). GT's are licensed by the Gas and Electricity Markets Authority to transport gas to consumers.

Gate closure

Gate Closure is the point in time when market participants notify the SO of their intended final physical position. It is set at one hour ahead of real time.

H

The Health and Safety Executive (HSE)

A public body responsible for regulating health and safety in Great Britain with the primary function to secure the health, safety and welfare of people at work and to protect others from risks to health and safety from work activity.

I

Interconnector

Equipment used to link electricity or gas systems, in particular between two Member States.

L

Licence conditions (obligations)

Obligations placed on the network companies to meet certain standards of performance. The Authority (GEMA) has the power to take appropriate enforcement action in the case of a failure to meet these obligations.

Linepack

The volume of gas within the National or Local Transmission System at any time.

Liquefied Natural Gas (LNG)

LNG consists mainly of methane gas liquefied at around -260 degrees Fahrenheit. Cooling and liquefying the gas reduces its volume by 600 times such that a tonne of LNG corresponds to about 1,400 cubic metres of methane in its gaseous state. LNG may be stored or transported by special tanker.

Low carbon economy

An economy which has a minimal output of greenhouse gas emissions.



M

Margin (in electricity)

Margin is the need for NGET to ensure that the units synchronised at any given time have sufficient spare capacity to ensure that the Short Term Operating Reserve Requirement (STORR) is met. The STORR is set such that there is a risk that total demand will not be able to be met on only 1 in 365 days.

Market Length

Market Length refers to the volume of excess demand (or supply) that exists at the point of gate closure. If generators generate more energy than they have contracted for and/or suppliers' customers consume less energy than their supplier has bought on their behalf, then the net effect is that there is a surplus of generation on the system. This is often described as a 'long' market. Conversely, if generators generate less energy than they have contracted for and suppliers' customers consume more energy than their supplier has bought on their behalf, then the net effect is that there is a shortfall of generation on the system. This is often described as a 'short' market.

N

National Grid Electricity Transmission (NGET)

NGET is the Transmission System Operator for Great Britain. As part of this role it is responsible for procuring balancing services to balance demand and supply and to ensure the security and quality of electricity supply across the Great Britain Transmission System.

National Grid Gas (NGG)

The licensed gas transporter responsible for the gas transmission system, and four of the regional gas distribution companies.

National Transmission System (NTS)

A high pressure system consisting of terminals, compressor stations, pipeline systems and offtakes. Designed to operate at pressures up to 85 bar. NTS pipelines transport gas from terminals to NTS offtakes.

National Electricity Transmission System Security and Quality of Supply Standard (NETS SQSS)

As referred to in the electricity Transmission Licence Standard Conditions C17 and D3, this is the standard in accordance with which the electricity transmission licensees shall plan, develop and operate the transmission system.

Net Present Value (NPV)

A NPV is the discounted sum of future cash flows, whether positive or negative, minus any initial investment.



Network charges

These are charges set for the use of network services.

O

On the day Commodity Market (OCM)

Enables anonymous financially cleared on the day trading between market participants. In its role as residual balancer, NGG trades gas on the OCM to resolve imbalances.

OFTO

Offshore Transmission Owner.

Operating Margins (OM) (in gas)

Gas used to maintain system pressures under specific circumstances including periods immediately after a supply loss or demand forecast change before other measures become effective and in the event of plant failure, such as pipe breaks and compressor trips.

Operating Margin (OM) (in electricity)

A requirement to ensure that the system security can be properly managed across power exchange and Balancing Mechanism timescales, i.e. 'up to' and 'at real time'.

Outputs

What the SOs are expected to deliver, for example, the gas SO (NGG) is expected to deliver efficient and timely connections.

Own Use Gas

Gas used by system operators to operate the transportation system, this includes gas used for compressor fuel, heating and venting.

P

Plexos

A modelling tool for power market analysis.

Price control

The control developed by the regulator to set targets and allowed revenues for network companies. The characteristics and mechanisms of this price control are developed by the regulator in the price control review period depending on network company performance over the last control period and predicted expenditure in the next.



R

Reactive Power

Power generation creates background energy which absorbs or generates reactive energy as a result of the creation of magnetic and electric fields. Reactive power needs to be provided to assist in balancing the system and retaining its integrity.

Reopeners

A process undertaken by Ofgem to reset the revenue allowances (or the parameters that give rise to revenue allowances) under a price control or incentive scheme before the scheduled next formal review date.

RIIO-T1

RIIO-T1 is the first transmission price control review under the new regulatory framework known as RIIO (Revenue = Incentives + Innovation + Outputs). The RIIO model builds on the previous RPI-X regime, but is designed to better meet the investment and innovation challenge by placing much more emphasis on incentives to drive the innovation needed to deliver a sustainable energy network at value for money to existing and future consumers.

S

Safety Case

A document required by the Gas Safety (Management) Regulations 1996. No person may convey gas without having a Safety Case accepted by the Health and Safety Executive.

Sharing factors

For cost incentives, these describe the percentage of profit or loss which the SO will have to bear if the relevant incentive performance measure falls below or exceeds the relevant incentive target. For output incentives, these describe the percentage of profit or loss which the SO will have to bear if the relevant incentive performance measure exceeds or falls below the relevant incentive target.

Short Term Operating Reserve (STOR)

A service that provides additional active power from generation and/or demand reduction.

Shrinkage

Shrinkage is a term used to describe gas either consumed within or lost from a transporter's system. For example, shrinkage can result from gas transmission companies using gas within their transportation systems to fuel gas compressors. At the distribution level, the majority of shrinkage results from gas escaping from old iron gas mains during transportation. Shrinkage also occurs when gas is stolen or not charged for in error.



SO External costs

The costs National Grid incurs in relation to the operation of the gas and electricity system. These costs include contracts for balancing activities in electricity, purchasing energy to transport gas and entering into trades on the commodity market (gas) and the Balancing Mechanism (electricity).

SO Internal costs

Internal costs relate to the SO's own costs associated with its SO activities, such as building, staff and IT costs.

Stakeholder

Stakeholders are those parties that are affected by, or represent those affected by, decisions made by network companies and Ofgem. As well as consumers and companies involved in the energy sector, this would for example include Government and environmental groups.

Storage (gas)

Installations owned by Gas Distribution Networks (GDNs) and storage capacity contracted from third parties eg salt cavities, liquefied natural gas (LNG), storage vessels and gas holders. Gas storage is required to balance diurnal and seasonal variations in supply and demand.

Sustainable energy sector

A sustainable energy sector is one which promotes security of supply over time; delivers a low carbon economy and associated environmental targets; and delivers related social objectives (e.g. fuel poverty targets).

System Average Price (SAP)

The System Average Price (SAP) is calculated daily as the sum of all gas balancing charges divided by the sum of all balancing transactions quantities in respect of that Day.

System event (in gas)

An event that requires the utilisation of Operating Margins to maintain safe pressures within the NTS. Potential System Events are split into three categories: i) major events (eg loss of supply infrastructure, loss of largest sub-terminal), ii) multiple events (eg compressor failures, pipe breaks), and iii) orderly rundown (e.g. maintain pressures in the event of a National Gas Supply Emergency).

System Operator (SO)

The entity charged with operating either the GB electricity or gas transmission system. NGET is the SO of the high voltage electricity transmission system for GB. NGG is the SO of the gas NTS for GB.



T

[Third Package \(Third Internal Energy Market Legislative Package\)](#)

The third package is a key step in implementation of the internal EU energy market. It recognises the need for better coordination between European network operators and continuing coordination between regulators at that level.

[Transmission losses](#)

Electricity lost on the GB transmission system through the physical process of transporting electricity across the network. The treatment of transmission losses is set out in the BSC.

[Transmission Owner \(TO\)](#)

There are three separate high voltage electricity Transmission Owners in GB. National Grid Electricity Transmission (NGET) owns and maintains the high voltage electricity transmission system in England and Wales. Scottish Hydro–Electric Transmission Limited (SHETL) is the electricity transmission licensee in Northern Scotland and Scottish Power Transmission Limited (SPT) is the electricity transmission licensee in Southern Scotland.

There is one gas Transmission Owner in Great Britain. National Grid Gas (NGG) owns and maintains the National Transmission System in Great Britain.

U

[Uncertainty mechanisms](#)

Uncertainty mechanisms allow changes to be made to the base revenue during the price control period to reflect significant cost changes that are expected to be outside the company's control. Examples include revenue triggers and volume drivers.

[Uniform Network Code \(UNC\)](#)

As of 1 May 2005, the UNC replaced National Grid Gas's Network Code as the contractual framework for the NTS, GDNs and system users.



Appendix 7 – Feedback Questionnaire

1.1. Ofgem considers that consultation is at the heart of good policy development. We are keen to consider any comments or complaints about the manner in which this consultation has been conducted. In any case we would be keen to get your answers to the following questions:

1. Do you have any comments about the overall process, which was adopted for this consultation?
2. Do you have any comments about the overall tone and content of the report?
3. Was the report easy to read and understand, could it have been better written?
4. To what extent did the report's conclusions provide a balanced view?
5. To what extent did the report make reasoned recommendations for improvement?
6. Please add any further comments?

1.2 Please send your comments to:

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