Promoting choice and value
for all gas and electricity consumers

System Operator incentive schemes from 2013: principles and policy

Consultation

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Overview:

This paper sets out our proposed objectives, policy and principles for the regulation of the gas and electricity System Operators (SO) from April 2013. Our proposals are based on the RIIO (Revenue= Incentives + Innovation + Outputs) principles for regulating monopoly energy companies.

The RIIO principles encourage long term thinking through a clear, transparent and stable regulatory framework. To this end we intend to fix the central SO regulatory framework (objectives, principles and the overall policy) for a period of eight years, albeit acknowledging that changes to the SO's role may require development of the regulatory framework.

This document is a consultation on our views on the SO regulatory framework, including preliminary SO outputs and cost incentive schemes. These views were developed following consideration of the current, and potential future, roles of the SOs, including where they overlap with the TOs' roles and the RIIO-T1 price control.

Context

The views set out in this consultation 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 to keep them as low as possible. 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. Based on our experience over the past years, and building on our RIIO principles for regulating monopoly energy companies, we consider that the best way of achieving long term value for money for consumers is by providing the SO with commercial incentives within a transparent regulatory framework. These incentives work by giving the SO an opportunity to share some of the gains (or losses) from cost reductions (or increases) and also ensure the SO is rewarded (penalised) for delivery of well specified outputs.

This work builds on previous material published in both SO incentive schemes and RIIO-T1 documents. It is consistent with the RIIO-T1 Strategy Decision document published in March 2011.

Associated documents

- System Operator incentive schemes from 2013, 14 June 2011, Ref 77/11: http://www.ofgem.gov.uk/Markets/WhlMkts/EffSystemOps/SystOpIncent/Documents1/SO%20incentives%20from%20April%202013%20Inital%20Views%20Consultation.pdf

- National Grid Electricity System Operator Incentives from 1 April 2011, 10 June 2011, Ref 76/11 http://www.ofgem.gov.uk/Markets/WhlMkts/EffSystemOps/SystOpIncent/Documents1/National%20Grid%20Electricity%20Transmission%20SO%20incentives%20from%201%20April%202011%20FINAL.pdf

- Handbook for implementing the RIIO model, 4 October 2010 http://www.ofgem.gov.uk/Networks/rpix20/ConsultDocs/Documents1/RIIO%20handbook.pdf.

- Decision on strategy for the next transmission price control – RIIO-T1, 31 March 2011, Ref46/11 http://www.ofgem.gov.uk/Networks/Trans/PriceControls/RIIO-T1/ConRes/Documents1/T1decision.pdf

- Initial assessment of RIIO-T1 business plans and proportionate treatment, 24 October 2011, Ref 136/11 http://www.ofgem.gov.uk/Networks/Trans/PriceControls/RIIO-T1/ConRes/Documents1/busplanletter.pdf

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Executive Summary

The gas and electricity systems will go through significant change over the coming years. 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 volatile use of gas as a result of intermittency in electricity and, potentially, more storage and LNG facilities connecting. Against this backdrop, it is even more important than ever that the gas and electricity System Operators (SOs) can show consumers that they are operating efficiently.

Meeting these challenges will require the 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 challenges on costs of performing the SO functions. 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 put sustainability alongside consumers at the heart of regulation. This will be the first SO regulatory framework based on the RIIO principles. We believe that the proposals in this document will provide the SO with strong incentives for efficient and timely delivery of outputs.

We have reviewed the roles of the gas and electricity SOs and identified a preliminary set of outputs that they will be required to deliver over the coming years. We have also set out how these outputs may evolve and the principles we will be using in incentivising delivery. In identifying the outputs we have carefully considered the overlap between the roles of the SOs and the TOs. There are strong links between many (but not all) of the SO and TO outputs and the SOs and TOs should be jointly accountable for the delivery of some of them.

To incentivise the SOs to deliver their outputs at long term value for money we have also identified a number of cost areas which could be incentivised. For each scheme we set out preliminary views on how they may operate, with a focus on encouraging efficient long term decision making.

We also recognise that the SO regulatory frameworks need to change to encourage SO-TO interactions to be transparently taken into account. With separate regulatory arrangements neither the SO or TO ordinarily consider the impact of their decisions on each other, except where they are under common ownership. Even in this case the extent to which SO and TO long term costs and output delivery are considered in a joined up way is affected by the incentive schemes. This includes setting the same sharing factor as is used in the final RIIO-T1 proposals where a cost or output

category involves strong SO-TO interactions. We recognise that this is a significant change with respect to sharing factors recently applied in SO incentive schemes.

Further, to ensure that joined up decisions are made where the SO and TOs are under separate ownership we set out proposals for an additional mechanism. Under which, in certain circumstances, the SO can pay the TOs to take actions which lead to a better outcome for the system as a whole.

We recognise that the SOs operate in an uncertain environment and that there are a number of potential risks to the delivery of SO outputs at long term value for money. The regulatory framework needs to establish a balance of risk between the SOs and customers. This balance needs to ensure that the SOs face strong incentives to manage these risks whilst not exposing it to unnecessary or unmanageable risks. Our proposals set out the principles we will apply when considering the introduction of mechanisms intended to achieve an efficient balance of risks.

One of the key components of the RIIO principles is to encourage long term thinking though a clear, transparent and stable regulatory framework. To this end we intend to fix the SO regulatory framework (the objectives, the principles and the overall policy) for a period of eight years. This matches the length of RIIO-T1. This will encourage joined up decision making between the SOs and TOs as the same principles will be applied to both for the same period starting from April 2013.

In committing to the regulatory framework for longer we recognise that there is the potential for the role of the SO and its functions to change over the period in response to policy and legal developments. For example, the government's Electricity Market Reform (EMR) is expanding the role of the SO. Under the EMR the SO will be endowed with the ability to offer low carbon and capacity contracts to deliver the government's policy on low carbon and renewable targets and on security of supply. We are working with DECC to consider how new responsibilities interact with existing SO and TO functions. We may then need to integrate the regulation of the SO's role in delivering EMR into our SO regulatory framework. In case of such major changes, we may need to reopen the SO regulatory framework and reassess it to ensure it remains relevant.

In response to the policy and principles we set out in this document we expect the SOs to develop well justified plans. These plans will set out their views on the levels of output and cost targets and how they plan to deliver against these. We are aware that the application of the RIIO principles to the SO regulatory framework represents a significant change in our approach from how we have set SO incentives in recent years. This document sets out in detail our proposals for the new SO regulatory framework. To ensure the changes are fully understood by the SO and industry we will also engage fully with relevant parties over the coming months. Nothing in this document reopens issues determined in the RIIO-T1 strategy decision.

We propose to present the proposals in this document to interested parties at the industry meetings in February. We expect NGG and NGET to deliver their well justified plans to us by 31 May 2012. We will then review and develop Initial Proposals to be published in the summer of 2012. We also plan to hold a stakeholder event shortly afterwards.

1. Introduction

In this chapter we introduce the consultation document and the principles and objective of the system operator regulatory framework from April 2013. We also provide an overview of the proposed framework.

1.1. This document sets out the principles that we are minded to use in designing and developing the regulatory framework for the gas and electricity system operators (SOs) to be implemented from April 2013. In the context of this document we use the term regulatory framework to mean the objectives, principles and policy for the regulation of the SO functions and the external costs incurred in performing these functions.

1.2. Based on the application of these principles, we set out our initial views on how we intend to incentivise the SOs to deliver their functions at value for money for consumers. Ofgem is in parallel developing price controls for the transmission operators (TOs) to be implemented from April 2013 using our RIIO (Revenue=Incentives + Innovation + Outputs) model[1]. SO internal costs are being considered as part of the RIIO-T1 process.

1.3. Our discussion builds on our June 2011 consultation. It also takes account and is consistent with our March 2011 RIIO-T1 strategy decision document(s) and our initial assessment of the TO business plans. It reflects our commitment to fundamentally review the way in which we regulate the gas and electricity SOs to ensure consistency with the principles of the RIIO model. In developing our thinking we have taken account of responses to the June consultation and ongoing discussions with the SOs and the TOs.

1.4. In June we explained the context in which we were reviewing the SO regulatory frameworks. We also set out the benefits of undertaking a wide ranging review of how best to regulate the SOs. Since then our work has focused on three areas:

- **SO outputs**: we have worked to provide clarity on what the SOs will be expected to deliver by looking at the role of the SO, considering responses to consultation, and considering alignment with what the TO will be expected to deliver under the RIIO framework;
- **SO-TO interactions**: we have considered further what 'aligning incentives' of SOs and TOs means for the SO incentives. We have explored implications for output incentives, length of schemes, sharing factors for cost incentives and wider consistency across the regulatory frameworks; and
- **Risk sharing and uncertainty mechanisms:** we have considered the question of how to determine appropriate risk sharing between the SOs and customers. We have developed our thinking on the implications for the design of incentive schemes.

1.5. Many of the principles set out have been consulted on previously and we are now keen to move forward with the development of the detail of the regulatory frameworks. In this context, we welcome responses on all aspects of this

[1] Information on the ongoing transmission price control review can be found on our website: http://www.ofgem.gov.uk/NETWORKS/TRANS/PRICECONTROLS/RIIO-T1/Pages/RIIO-T1.aspx.

consultation. We are particularly interested in hearing views on how best to apply the principles and turn the policy proposals into concrete output and cost incentive schemes. We will be working with the SOs to develop the schemes in the required timescales and will take account of responses to this consultation in this work.

Principles for designing SO regulatory frameworks

1.6. Taking account of responses to our June consultation and the principles used to design and implement the RIIO model we are minded to regulate the SOs in a way that is consistent with the following principles:

a) there should be clarity on what the SOs are expected to deliver and on how the regulatory framework would be adapted if the role of the SOs change;
b) the regulatory framework should place strong incentives on the SOs to operate the electricity and gas systems in the most efficient manner possible;
c) the overall regulatory framework should reflect a fair balance of risk and reward between the SOs and consumers;
d) the regulatory framework should not result in the SOs distorting competition in the wholesale or retail gas and electricity markets;
e) the regulatory framework should be designed to limit the risk of unintended consequences;
f) there should be transparency about how SO decisions are made, how trade-offs between operational (SO led) and investment (TO led) solutions are made and what the costs (financial and environmental) of different decisions are over the long term;
g) there should be regulatory commitment to the design of the regulatory framework with transparency on how and under what circumstances the regulatory framework would be adapted;
h) where there are interactions between the SO and other parties, notably the TOs, the incentives should be aligned to encourage these interactions to be considered in a manner that is consistent with joint optimisation of output delivery and cost savings; and
i) the new regulatory framework should build on existing schemes where these are consistent with the principles and objectives set out here, ensuring that we do not have 'change for change's sake'.

1.7. We recognise that the principle to align SO-TO incentives could have a number of potentially significant implications for the design of the SO regulatory framework. We have therefore considered further what this principle means in practice. We consider that to align the incentives it is important to have:

- consistent high level objectives overriding the design of the SO and TO regulatory frameworks and aligned outputs, moving the SOs and the TOs in the same direction where they have common responsibility;
- common principles for designing regulatory frameworks for monopoly businesses, recognising that incentive schemes themselves may be designed and operated differently to reflect the different nature of the SO and TO businesses;
- output and cost incentives that encourage efficient delivery across SO and TO functions. Where there are strong interactions between SO and TO decisions this may mean aligning the strength of SO incentives with those applied to the TOs; and

- additional arrangements where alignment of outputs and incentive strength is not enough to encourage joined up optimisation of costs and output delivery. This includes a payment mechanism from the electricity SO to the Scottish TOs and potentially to the OFTOs.

1.8. We will use a common objective and set of principles to design the gas and electricity SO regulatory frameworks. However, when applying these principles we are mindful of the different roles, responsibilities, institutional and ownership arrangements between the sectors. This will result in the specific details of the gas and electricity SO regulatory frameworks being different.

Objective of the SO regulatory framework

1.9. Consistent with the duties of the Gas and Electricity Markets Authority (the Authority), the objectives of our RIIO model for regulating energy network companies, and wider Great Britain (GB) and European Union (EU) energy policy we propose to develop regulatory frameworks for the SO from April 2013 that encourage the SOs to:

- play a full role in delivering and operating a sustainable energy sector (integrated with EU markets); and
- operate the electricity and gas systems in a way that achieves value for money for existing and future consumers.

1.10. We emphasise the importance of ensuring an integrated European system, as this is core to the obligations set out under the Third Package. This consistency is a key starting point to aligning incentives, as it provides a common focal point for the development of the SO and TO regulatory frameworks.

Overview of SO regulatory frameworks from April 2013

1.11. The gas and electricity systems will go through significant change over the coming years. 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 volatile use of gas as a result of intermittency in electricity and, potentially, more storage and LNG facilities connecting. Against this backdrop, it is even more important than ever that the gas and electricity SOs can show consumers that they are operating efficiently.

1.12. Meeting these challenges will require the SOs to play a full role in delivering a sustainable energy system that is robust to the challenges they face. Applying the principles set out above, and considering responses to our June consultation and ongoing developments in the RIIO-T1 process, we will develop regulatory frameworks to ensure they provide incentives to the SOs to deliver at long term value for money.

1.13. The new regulatory frameworks will include the following components:

- **Output incentive schemes:** The SO regulatory frameworks will be outputs led. We will set out what outputs the SOs will be held to account to deliver.

Delivery of these outputs will be incentivised through licence requirements, reputational incentives and/or financial incentive schemes. We will set out how output incentive schemes may be adapted over time.

- **Cost incentive schemes:** The SO regulatory frameworks will be designed to encourage the SOs to deliver outputs at long term value for money. For categories of SO external costs we will set a cost target and an upfront sharing factor that determines how cost reductions (or increases) are shared between the SO and consumers. The cost incentive schemes will include uncertainty mechanisms where appropriate.
- **SO-TO interactions:** The SO regulatory frameworks will encourage the SOs to work with the TOs to identify behavioural changes that could result in overall lower costs of output delivery for consumers. We will place transparency requirements on the SOs to demonstrate how interactions with the TOs and other parties have been reflected in business plans and ongoing decision making. The SO will be expected to adequately compensate the TO for any changes through internal arrangements where there is common ownership. In the case of separate ownership this could be through a payment from the electricity SO to the Scottish TOs, and potentially the OFTOs, for behavioural changes such as changes to outage planning.

1.14. The objectives, principles and policies of the SO regulatory frameworks will be in place for eight years (until end of March 2021). Some incentive schemes may be set for a shorter period and there may be mechanisms in place to allow for changes to be made to individual incentive schemes, or to the set of schemes, during this period.

1.15. Table 1.1 provides an overview of the proposed structure of the SO regulatory frameworks from April 2013 and demonstrates consistency with the RIIO-T1 frameworks.

Table 1.1: SO regulatory frameworks from April 2013

	Electricity		Gas	
	SO	**RIIO-T1**	**SO**	**RIIO-T1**
Length (Chapter 2)	Regulatory framework set for eight years, individual schemes may be of shorter duration	Eight years with potential mid-period review of outputs	Regulatory framework set for eight years, individual schemes may be of shorter duration	Eight years with potential mid-period review of outputs
Output categories (Chapter 3)	1. Safety 2. Environmental impact 3. Connections 4. Reliability and availability 5. Stakeholders satisfied 6. Balanced system 7. Provision of information	1. Safety 2. Environmental impact 3. Connections 4. Reliability and availability 5. Customer satisfaction	1. Safety 2. Environmental impact 3. Connections 4. Reliability and availability 5. Stakeholders satisfied 6. Balanced system 7. Provision of information	1. Safety 2. Environmental impact 3. Connections 4. Reliability and availability 5. Customer satisfaction
Output incentive schemes (Chapter 3)	Seven output schemes Mix of legal requirements, reputational incentives and financial incentives	Ten output schemes Mix of legal requirements, reputational incentives and financial incentives	Eight output schemes Mix of legal requirements, reputational incentives and financial incentives	Six output schemes Mix of legal requirements, reputational incentives and financial incentives
Cost incentive schemes (Chapter 4)	*Total balancing cost* 40-50% sharing factor	40-50% sharing factor for network total costs and SO internal costs (precise level to be determined through the Information Quality Incentive (IQI))	*Shrinkage cost* 40-50% sharing factor *Operating margins cost* 20% sharing factor *Potential residual balancing costs scheme*	40-50% sharing factor for network total costs and SO internal costs (precise level to be determined through the IQI)
SO-TO interactions (Chapter 4)	Requirements for transparency on joined up business planning and decision making. Mechanism for SO to make payments to Scottish TOs to facilitate optimisation of joint costs related to behavioural changes (e.g. outage planning).	In well justified business plans TOs required to take account of interactions with SO, for example through network availability policies. Internal SO costs price control.	Requirements for transparency on joined up planning and decision making.	In well justified business plans TOs required to take account of interactions with SO, for example through network availability policies. Internal SO costs price control.

Document structure

1.16. The remainder of this consultation is structured as follows, with additional information available in the appendices.

- **Chapter 2** describes the role of the gas and electricity SOs and identifies potential changes to those roles. We explain what we mean by the SO playing a full role, and outline the interactions that the SO will need to consider, most notably with the TO, when doing this. We also discuss the principles that we will consider when deciding the length of time over which the SO regulatory frameworks should be fixed.
- **Chapter 3** sets out the output categories that we consider are relevant for the gas and electricity SO, reflecting our assessment of the role of the SO in each sector. We explain how output incentive schemes will be developed for the SOs and present our views on what the output schemes might look like.
- **Chapter 4** explains the different elements of the SO regulatory framework that will provide the SOs with incentives to identify the lowest, long term, least cost way of delivering outputs. We describe the principles and processes that we will use to set cost incentive schemes and present our views on what the cost incentive schemes will look like. We also consider whether additional mechanisms are needed to further interactions between the SO and the TOs that encourage long term total efficiency savings to be realised.
- **Chapter 5** considers the question of how best to develop risk sharing arrangements between the SO and those paying SO charges (industry and ultimately consumers). We also discuss the principles that need to be considered when deciding whether and how to include risk sharing or uncertainty mechanisms, including caps and floors, in the SO output and cost incentive schemes.
- **Chapter 6** provides details on how to respond to this consultation and explains the process and timing for setting SO regulatory frameworks from April 2013.

2. Playing a full role

In this chapter we provide an overview of the roles of the electricity and gas SOs. We then explain what we mean by the SOs playing a full role in delivering and operating a sustainable energy system. This is in terms of taking a proactive approach, delivering long term value for money and explaining and taking account of interactions with other parties, particularly the TOs.

Question 1: Do you consider that we have captured the full role of the SOs going forward?
Question 2: Do you consider that our minded to position on the length of the regulatory framework is appropriate?
Question 3: Do you consider that our proposals regarding SO-TO interactions provide the SOs with sufficient incentive to consider interactions with the TO in a longer term context?

2.1. We want the SOs to play a full role in delivering and operating a sustainable energy sector (integrated with EU markets). We want them to operate the electricity and gas systems in a way that is value for money for existing and future consumers.

2.2. Having clarity on what the SOs' responsibilities are and what we mean by "playing a full role" enables us to develop relevant SO output incentive schemes. Our understanding of what is needed to play a full role and deliver value for money for existing and future consumers also informs our thinking on the appropriate length of cost and output incentive schemes and the design of cost incentive schemes.

The roles of the gas and electricity SOs

2.3. We have reviewed the legal roles and responsibilities of the SOs in the gas and electricity sectors and considered how these roles may change going forward.

2.4. The electricity and gas SOs have wide and varied functions. We can categorise the SO role into two broad areas:

- **core SO role:** this includes the delivery of a reliable and economic system including system balancing and constraint management;
- **wider SO role:** this includes facilitating network connections and investment, calculating network charges and providing information to the market. The SOs also play a central role in the development of commercial and regulatory frameworks at the GB and European level.

2.5. The SO incentive schemes have traditionally covered the core role and selected aspects of the wider role.

2.6. Importantly, in undertaking these roles the SOs must often work with the TOs to achieve the required outputs. As a result the SOs may need to assume a joint responsibility with the TOs for a particular outcome or the SOs may need to take into account interactions with the activities of the TOs in the delivery of an outcome. Joint responsibility occurs, for example, with respect to network design and planning (especially with respect to managing network constraints), maintenance and outage planning, and specifically in respect of gas, ensuring capacity is available.

2.7. Going forward, the SOs are likely to face a number of challenges and opportunities which could significantly change the way they need to operate their systems. These challenges (and opportunities) can be categorised into three main areas:

- de-carbonisation of the energy supply, including implementation of policies designed to facilitate this;
- increased interconnection capability and implementation of policies affecting the use of interconnectors to increase market integration at a European level; and
- security of supply.

2.8. With respect to the challenges associated with de-carbonisation of energy supply, we recognise that the generation mix will significantly change in the coming years. This is as increasing levels of offshore wind and other types of renewable generation come on line. The increase in intermittent generation will provide two main areas of challenge in respect of the electricity system. The requirement for additional reserve (to ensure that additional generation is available should output from intermittent generation reduce) and a more congested system[2]. These developments will provide particular challenges for the electricity SO in how it manages the electricity system, for example, ensuring it purchases efficient levels of reserve.

2.9. Intermittency in the electricity system is likely to have a knock on effect on the gas system. The increasing use of intermittent wind generation will require the use of gas fired generation as back up to meet demand at times when it is not available. This in turn will increase the challenges the gas SO faces with respect to the operation of the gas system. It will need to ensure that linepack stays within safe operation limits (as a result of the increasing variability through the day of demand from CCGTs). This may require the SO to take additional balancing actions. We expect the SOs to step up to play a full role in addressing these challenges.

2.10. The SOs will also have to be able to effectively respond to other measures taken to address climate change. These include, but are not limited to, the introduction of smart meters and the increasing use of demand side response (DSR), both in gas and electricity. The SOs will therefore need to play an important role in developing appropriate systems and frameworks to ensure that the impact of these changes are managed effectively and that value for money is achieved.

2.11. In the European context the development of network codes in several areas[3] will affect the SOs' interaction with neighbouring gas and electricity markets. The new network codes may change the way the GB markets' activities are coordinated with other European markets, including system operation. In addition, electricity interconnector capacity is forecast to increase significantly from its current level of 3.5GW. The additional interconnectors will improve access to other European

[2] Additional generation is likely to be connected to the system before completion of network reinforcement work. In addition most of the new intermittent generation connecting to the system will have a relative low load factor and will share capacity with back up thermal generation. Network flows are also likely to change as a result of new generation connecting and old generation being decommissioned. The impact of these changes on the system is likely to be higher volumes of more volatile constraints on the system.

[3] For example, network codes are being delivered in respect of: balancing, congestion management, capacity allocation mechanism, system operation and grid connection.

markets. They could bring benefits in terms of energy balancing and security of supply, but they may also bring additional complexity to system operation.

2.12. The third challenge faced is how to maintain security of supply in the face of declining national supplies of fossil fuels (and the need to decarbonise the economy). The electricity and gas SOs could play a role in addressing this security of supply issue. For example, the SOs could contribute to greater security of supply by improving the way in which the system is managed (e.g. through the facilitation of demand side response). They could also take advantage of initiatives developed at EU level (e.g. ensuring that interconnectors are used efficiently).

2.13. The SOs may also be given more formal roles in respect of security of supply. The Department of Energy and Climate Change's (DECC) Electricity Market Reform (EMR)[4] is a response to this and its recommendations will have a significant impact on the role of the electricity SO. The proposal that the SO will be responsible for delivering the capacity mechanism and Fit CfDs will impact how the electricity SO fulfils its core functions and gives the electricity SO additional responsibilities. Higher dependence on gas imports has raised some security of supply concerns that are being addressed as part of the gas the gas Security of Supply Significant Code Review (gas SCR)[5]; and our review of gas security of supply[6] for DECC.

What do we mean by 'play a full role'?

2.14. We do not want to micromanage the SOs. However, we consider that it would be beneficial to outline the behaviours and decision making that we consider are consistent with the SO meeting the objectives of the new SO regulatory framework. Specifically, we consider that an SO that is meeting these objectives would:

- take a proactive approach and anticipate future developments;
- deliver long term value for money; and
- take into account SO-TO interactions.

2.15. We recognise that the SOs respond to regulatory incentives. We need therefore to change these incentives to encourage the SOs to step up to meet the objectives of the regulatory frameworks. In particular, we need to broaden the scope of the regulatory frameworks, provide greater clarity on what outputs the SOs are expected to deliver and ensure that incentives are focused on long term output delivery and long term costs. We also need to ensure that the SOs are encouraged to consider whether there are more effective and efficient ways of delivering over the long term that involve interactions with other parties, notably the TOs.

Take a proactive approach and anticipate future developments

2.16. Meeting the objective of the SO regulatory frameworks will require the SOs to be even more proactive participants in the energy sector. They should continue to

[4] Information on the EMR can be found at: http://www.decc.gov.uk/en/content/cms/legislation/white_papers/emr_wp_2011/emr_wp_2011.aspx
[5] Information in respect of the SCR can be found at: http://www.ofgem.gov.uk/Markets/WhlMkts/CompandEff/GasSCR/Pages/GasSCR.aspx
[6] The relevant press release can be found at: http://www.ofgem.gov.uk/Media/PressRel/Documents1/huhne%20asks%20ofgem%20to%20report%20on%20longer%20term%20gas%20security.pdf

look actively for ways to improve how they deliver their outputs and they should be even more forward looking.

2.17. This covers a range of behaviours that the SOs should strive to display, including, but not limited to:

- consistently looking to do more with less;
- continually testing options of delivery;
- being open to, and engaging, in stakeholder discussions (domestic and international);
- facilitating a culture that recognises the importance of moving beyond the status quo;
- striving to be at the forefront of thought regarding innovative potential solutions to current and future energy issues;
- actively considering how its role may change going forward and how best it can position itself;
- taking into account the impact its decisions, including ensuring that there is no distortionary impact on upstream and downstream markets;
- considering the environmental impact of its decisions; and
- appropriately managing current and expected risks.

2.18. Some of the areas where we consider that the SOs can be proactive include:

- facilitating greater integration of renewable energy by considering the range of issues associated with wind participation in the system;
- exploring possible reform to SQSS arrangements, to allow security objectives to be met at lower cost – for example, having a targeted N-1 (rather than N-2) approach for some infrastructure;
- exploring opportunities for greater cooperation with the distribution network operators that might offer lower cost solutions compared with a 'transmission only' approach;
- exploring the scope for developing the market for and use of DSR with respect to the SO potentially being able to increase the options it has to procure various balancing services;
- considering its customers' needs for a range of issues, not least for gas connections; and
- considering the changes that will be necessary due to closer integration with Europe and any domestic changes.

Deliver long term value for money

2.19. Meeting the objective of the SO regulatory frameworks from April 2013 will require the SOs to consider sustainable output delivery and cost efficiency over the longer term. An SO that is considering the longer term is more likely to identify efficient and sustainable means of delivering outputs as it will take account of options for delivering outputs that involve high upfront costs and benefits over the long term and/or seek out longer term contracts/positions where this is the efficient option. It is also more likely to take account of SO-TO interactions that affect costs over time; and to develop new business arrangements and propose changes to industry code requirements, but not take undue risks that could affect long term delivery of outputs and ultimately increase costs to consumers.

2.20. There are a number of different ways to encourage a company to focus on the longer term. We will expect the SO to set out its proposals for the 2013 regulatory

framework in the context of a longer term strategy. This will be consistent with the requirements on the TOs for their well-justified business plans.

2.21. We are also proposing that the overarching SO regulatory framework set out in this document is put in place for an eight year period. This means that the objectives, principles and policies for the regulatory framework will be fixed until end March 2021 and the next full review of the gas and electricity SO regulatory framework will take place alongside the next full TO price control review (RIIO-T2 in 2021). Most outputs will also be defined for eight years, and details of how individual schemes might be adapted during the period will be specified upfront.

2.22. Within this overarching eight year framework, we recognise that the optimal number of years for individual components may vary. We have therefore considered four options for each of the output and cost incentive schemes, trading off the desirability of longer term with an assessment of what can feasibly be fixed.

- **Eight year schemes**: we would fix the methodology[7] for setting the scheme target for eight years, including the rules for adjusting the target for factors outside of the SO's control during the period. We would also commit to the sharing factor for eight years. We would be transparent on what uncertainty mechanisms would be in place during the period. Unless they were a response to fundamental changes in the SO operating environment (and therefore covered by an uncertainty mechanism) we would not make adjustments for decisions made by the SO during the period. This will ensure the SO has confidence in our commitment to the principles of a fixed sharing factor.
- **Four + four schemes**: we would commit to the methodology for setting the scheme targets and sharing factors for the first four years. We would provide an indicative set of incentive schemes for the second four year period using the same methodology. We would set out the uncertainty mechanisms that would be in place for each four year period and we would commit to not make any other changes to the scheme during the first four years. We would undertake a review of the incentive schemes in year 4, with a view to confirming that the existing scheme methodology would be retained unless there had been a significant change in circumstances or we found that there were serious unintended consequences arising from the scheme. We may want to include new outputs or cost categories to the incentive scheme package through this four year review or we may want to discontinue some incentive schemes where they are considered redundant (e.g. because competitive forces place sufficient pressure on the SO in particular areas). We would also consider any implications for the SO if there is a review of the TO outputs at this time[8]. We could use the scheme review in year 4 to update the parameterisation of the targets and sharing factors where these were not already determined through an automatic updating process.
- **Four year schemes**: this option would work in the same way as the eight year scheme, but with everything fixed for four years. There would be a full review of the incentive schemes in year 4, and there would be no attempt to provide a signal or expectation of scheme parameters for the second four year period at the outset.
- **Other length schemes**: for some schemes it may be appropriate to fix the target and incentive rate for a different length (e.g. two years or six years).

[7] Applying a fixed methodology could result in different scheme targets and incentive rates in different years, or different targets and the same incentive rate, or the same parameters in all years.
[8] Under the RIIO model there is provision for a four year review of outputs.

We would need to have a clear reason why the chosen number of years was appropriate. A shorter scheme length may be appropriate where we did not consider that longer term thinking was relevant or where the scheme was new and there was a concern that it would need to be tested and refined initially, potentially with a commitment to extend in the future. Similarly, if a scheme can only become operational after 2013, for example because the SO needs time to develop a required process or information, then a scheme length that allows for alignment of all schemes in 2021 may be needed.

2.23. We set out in Table 2.1 the factors that we will consider when deciding on the appropriate scheme length for different output and cost incentive schemes.

Table 2.1: Factors to consider when deciding on scheme length

Alignment of SO-TO incentives	Where there are overlapping outputs and/or joined up costs with the TO it would be appropriate to align the timing at which the TO price control and related SO cost and output incentive schemes are reviewed.
Impact on risk and company financeability	The length of scheme decision will involve a judgement on how to balance any potential increase in risk to company revenues, and potentially financeability, with the need to provide powerful incentives to deliver outputs and value for money for existing and future consumers.
Incentive effect of uncertainty mechanisms	When considering the length of scheme we will balance the benefits of uncertainty mechanisms with any potential implications for output delivery and cost efficiency incentives.
Predictability of costs and outputs	Longer schemes will be more credible where costs and outputs are generally considered to be relatively stable and follow a predictable path.
Confidence in data and modelling	We will set scheme length to encourage the SOs to develop information and models consistent with longer term thinking but will also need to consider what can credibly be delivered for April 2013. We will consider whether and how to transition to longer schemes where reliable data and models are not ready for April 2013.
Consistency across incentive schemes	We recognise the desirability of having the cost and output incentive schemes in each of the sectors set for the same length of time but recognise that it may be appropriate to have some fixed for different lengths of time when other factors are taken into account.

2.24. We will work with the SOs to finalise, for each output and cost incentive scheme, the appropriate scheme length. We will also work with the SOs to identify which elements of the schemes may need to be updated during the fixed period, with the aim of ensuring that there is transparency and clarity on how the incentive schemes will work and evolve over time.

Take into account SO-TO interactions

2.25. When the gas and electricity SOs are meeting the objective of the regulatory frameworks there will be a number of areas where they interact with the TOs, both in output delivery and cost efficiency. The SOs should consider a range of options when deciding how best to deliver outputs at least cost over time. These include whether the most effective and efficient way of delivery is for the TO to change its behaviour. We would expect the SO to only pursue this option where in aggregate it would

result in a total cost saving to consumers. Also, that it would not jeopardise delivery of TO baseline outputs or SO outputs. We expect the SO to adapt and take account of all relevant information when considering on an ongoing basis how best to take account of SO-TO interactions.

2.26. We want the SOs to consider interactions with the TOs on an ongoing basis.

- **At the time of regulatory reviews:** we want the SOs to work with the TOs when developing business plans to identify appropriate baselines for outputs that are consistent with both meeting regulatory requirements and minimising total consumers costs. This relates to both TO business plans for price control reviews and the development of SO plans for the SO regulatory frameworks.
- **During the regulatory period**: we want the SOs to continue to work with the TOs to identify potential efficiency savings on an ongoing basis This includes considering how best to deliver outputs that they are jointly responsible for. We expect the SO to continuously consider the joint impact of SO and TO decisions where there are clear interactions. As part of this the SO may need to consider how to incentivise the TO to change its behaviour. This should be informed by the development of a network availability policy by the TOs under RIIO-T1. Work is ongoing to finalise the details of what is included in such policies.

2.27. We recognise that achieving this level of interaction has been complicated by the different history and timing of the TO and SO regulatory reviews. However, the alignment of RIIO-T1 and SO incentive schemes for April 2013 should help achieve this. The design of the regulatory frameworks is also influenced by the ownership arrangements in place.

- In gas, we would expect NGG to internalise trade-offs between TO and SO output delivery and cost incentives. We would expect the company to consider the gas transmission system as a whole in a joined up way. It is for us to ensure that the regulatory framework does not distort such joined up internal decision making; that there is transparency in how trade-offs between operational and investment decisions are taken; and that decisions are taken in a manner that is consistent with the objectives of the regulatory frameworks.
- In electricity, NGET is both the GBSO and the England and Wales TO. We would expect that for England and Wales the interactions between the SO and TO would be internalised within NGET, in the same way as for NGG. However, the GBSO needs to consider the system as a whole and in this context it needs to consider interactions with the GB transmission network as a whole, including the Scottish transmission networks owned and operated by SHETL and SPTL. These are interactions that will not be internalised in NGET's decision making. We need to ensure that the SO's regulatory framework encourages the electricity GBSO to take account of interactions with all three TOs in a consistent way. In a number of areas the SO, with a view of the whole system, may be best placed to identify what the trade-offs are.

2.28. We recognise that the SO regulatory frameworks need to change to encourage the SO to take account of SO-TO interactions. With separate regulatory arrangements neither the SO or TO ordinarily consider the impact of their decisions on each other, except where the TO and SO are under common ownership. Even with common ownership the extent to which SO and TO long term costs and output delivery are considered in a joined up way is affected by the incentive schemes.

2.29. In June we emphasised that our aim is as far as possible to align the SO and TO regulatory frameworks and the associated incentives. Since then we have reviewed responses to our consultation and the TO draft business plans to develop our thinking on how best to ensure that interactions are effectively incorporated into the SO schemes. We intend to do this in a number of ways:

- we are adopting the overarching outputs led, incentive based framework of the RIIO-model and applying similar principles to SO regulation as we use for TO regulation;
- when considering the appropriate outputs to hold the SO to account to deliver we are including outputs where the SO and TO might be considered jointly responsible for delivery, and we take account of this joint responsibility in the design of the output incentive schemes;
- where there are close interactions between SO costs and TO behavioural and investment decisions our starting point is that the sharing factor of relevant cost incentive schemes should be set at the same level;
- when considering the appropriate length of time over which an SO output or cost incentive scheme is considered fixed we are taking account of the benefits of aligning the timing with the eight year RIIO-T1;
- including a requirement on NGG and NGET, as SO and TO, to transparently demonstrate how SO-TO interactions are taken into account in business plans and ongoing decision making;
- in electricity, we set out a payment mechanism that allows for the GBSO to make payments to SHETL and SPTL, and potentially to OFTOs, to change behaviour that would reduce SO costs over time. The payment mechanism is expected to be used during the RIIO-T1 period and should only be used for behaviour changes that would not jeopardise delivery of baseline TO or SO outputs; and
- by using a common set of principles for considering whether and how to use uncertainty mechanisms when developing RIIO-T1 and SO cost and output incentive schemes.

SO-SO interactions

2.30. The decisions of the electricity SO impact on the gas SO, and vice versa. For example, how the electricity SO manages the system when there is increasing amounts of generation from intermittent wind sources will have an impact on the gas system. We want National Grid, as owner of the gas and electricity SO, to demonstrate that it is taking account of these interactions when making decisions under the SO regulatory framework from April 2013. Through the framework we will encourage greater transparency of SO-SO interactions and their impact on the decision making of the SOs.

3. Outputs and output incentives

In this chapter we set out the principles and process that we use to design the output incentive schemes. We then set out in summary form the outputs we consider are appropriate to incentivise the SOs on and the nature of those incentives. Appendices 4 and 5 contain a discussion of why we consider these to be the appropriate outputs and incentives.

Question 4: Do you agree with our minded to position on SO outputs and the interactions with SO and TO outputs?
Question 5: Do you agree with our minded to position on the period for which the various outputs and associated incentives will be fixed?
Question 6: Do you agree with our views on incentivising SO outputs?
Question 7: What areas, in addition to DSR, should a broad environmental output cover? What is your view on having a financial (rather than a reputational) incentive on NGET and/or NGG as SOs to encourage them to deliver against a broad environmental output?
Question 8: What is your view on having a financial output incentive on the accuracy of NGET's forecast of wind generation and the timeliness and availability of that information on its website?
Question 9: What is your view on introducing an incentive based on the total cost of NGG's balancing actions? Should such a total cost incentive replace or be in addition to current incentives for NGG to minimise the impact of its balancing actions?

3.1. Consistent with the RIIO model used to regulate the TOs, the SO regulatory frameworks will be output led. By defining what the SOs are required to deliver, companies face powerful incentives to seek the best sustainable and efficient solutions to delivering the services required by customers.

3.2. Since the release of our June 2011 consultation and the receipt of responses to it, we have been considering the merits of the outputs that we identified for the gas and electricity SO incentive schemes from 2013. Specifically, we have:

- re–examined the merit of the outputs identified in the consultation and those that have been identified subsequently, either by us or by stakeholders;
- considered the outputs identified within RIIO-T1 and have recast the way in which we represent the SOs' outputs to facilitate the development of a more RIIO-T1 consistent approach to measure the performance of the SOs;
- considered the interactions of the outputs identified with those of the TOs, in particular in respect of the information provided by the TOs in their July business plans; and
- reached an initial view on how the SOs should be incentivised to meet their outputs from April 2013.

Setting output incentives – principles and process

3.3. We will use a set of output incentive schemes in the SO regulatory frameworks to encourage the SOs to deliver outputs that are consistent with what is needed for delivery of a sustainable energy system (integrated with EU markets). Consistent with RIIO we identify appropriate output categories and the set of outputs within each category that we will hold the SO to account to deliver. Baseline targets

will be set for each output. We then need to ensure that the SO faces sufficient upside and/or downside, either in terms of reputational effects or financial impact, to motivate them to ensure that these outputs are delivered.

Setting the outputs

3.4. We describe below the outputs that we are minded to require the SOs to deliver from April 2013. We identified the output categories and the outputs within each category by reviewing the roles of the SOs, as set out in licences and wider legislation. We have considered what requirements are already included in SO incentive schemes and assessed the extent to which there is a need for SO outputs to be aligned to TO outputs identified for RIIO-T1.

3.5. We recognise that there are areas where the roles of the SOs and TOs overlap and they have joint responsibility for delivering outputs. This means that in some areas output incentives set under RIIO-T1, though aimed at incentivising TO performance, will capture aspects of the SO role. Where roles and outputs overlap we have sought to ensure that the regulatory arrangements (irrespective of where the responsibility rests) is one that ensures the best overall outcome for consumers. This means that if an output has already been fully captured under RIIO-T1 we will not look to incentivise the SO for that output again. That said we will introduce SO outputs if we consider these will lead to improvements in areas of joint responsibility.

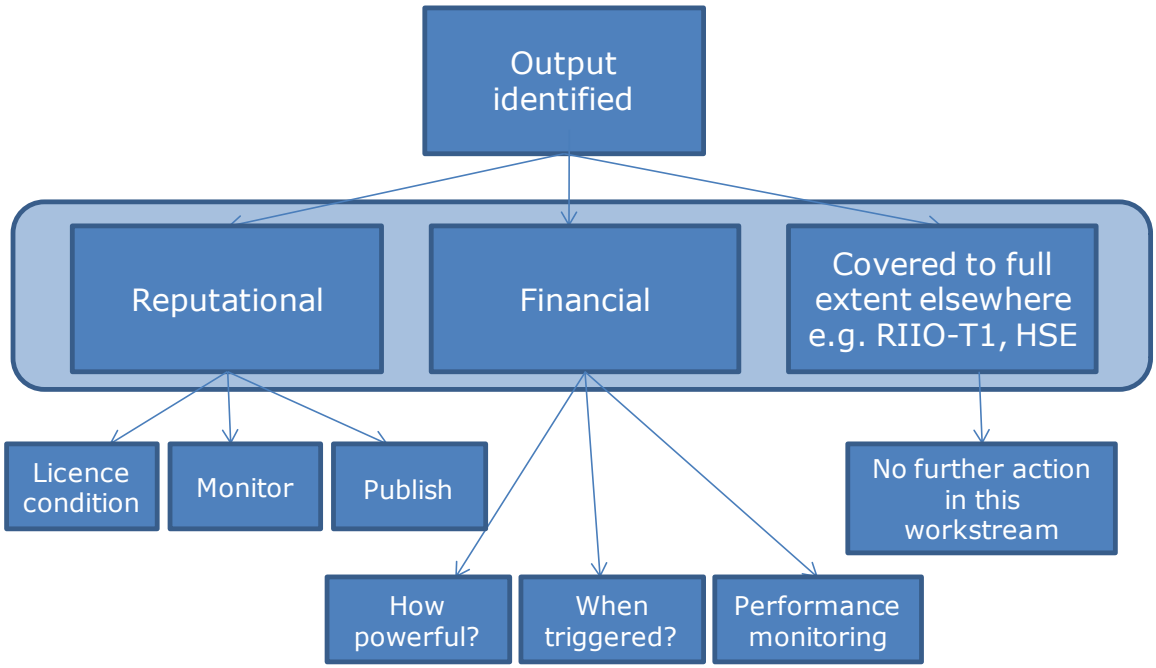
3.6. The next step for the design of the output incentive schemes is to define a clear baseline target for each output. We will work with the SOs to develop these targets, taking account of any alignment and interaction with outputs developed for the TOs in RIIO-T1. We will build on existing definitions in current SO incentive schemes or in licence conditions where possible.

Incentivising delivery of the outputs

3.7. Figure 3.1 summarises the different stages of decision making relating to the design of the output incentives for the SO. Reputational incentives are non financial incentives that leverage off the value companies place on establishing or maintaining a good track record for delivery with their stakeholders. They will usually involve the measurement of the SO's performance on delivery of outputs which will then be publicised to groups of interested stakeholders.

3.8. The approach to incentivisation selected will be what we consider most likely to facilitate the effective delivery of individual outputs. In our selection we will have considered how the incentives as a package work, taking into account how the outputs interact with each other and the relative importance of the outputs. We will also consider interactions with the TO output incentive arrangements, to ensure that joined up or aligned outputs are clear and that it is clear where incentives and responsibility for delivery lie. We will sense check the incentive mechanisms to identify any potential unintended consequences for the individual outputs. We will ensure that the package of incentives exposes the SOs to an appropriate level of risk.

Figure 3.1: Deciding how to design SO output incentive schemes



3.9. While we will determine the appropriate form of any output incentive to be applied on the SO we encourage all stakeholders, including the SOs, to provide views on how best to develop and design output incentive schemes in gas and electricity.

3.10. When deciding whether a specific output incentive scheme is needed in the SO regulatory frameworks we will:

- review whether there is a clear legal obligation that is sufficient to ensure the delivery of an output (e.g. the safety of the SO's employees are protected by health and safety legislation); and
- consider, for outputs where there is joint TO and SO responsibility, whether sufficient incentives are provided on the company through RIIO-T1.

3.11. Where we determine that additional incentives are needed on the SO to ensure that it is encouraged to focus on delivery of specific outputs we will determine whether a reputational or financial incentive is needed. We would expect to use reputational incentives where:

- we do not have sufficient confidence in data on the output to introduce a financial incentive scheme;
- we do not consider it appropriate for consumers to pay extra to incentivise delivery of the output, but we want to ensure that the SO is held to account to deliver it; and
- the output is already adequately financial incentivised through an output incentive placed on the TO and we consider it would be inappropriate for consumers to pay twice for output delivery. But we want to focus the SO's attention on the output and encourage specific behaviour from the SO which the other incentive does not encourage.

3.12. For some outputs we will consider it appropriate to set a financial incentive scheme to encourage delivery of the output. For these we need to decide:

- the incentive strength (i.e. the size of any reward/ penalty);
- whether the incentive should be symmetric or not: for some outputs there will be penalties for delivering less but not for delivering more (or vice versa);
- whether to have marginal incentives with reward/penalty varying according to the size of any incremental variation from the baseline target set at the beginning of the incentive scheme, or to have a fixed reward/penalty dependent on whether the output is delivered or not; and
- whether or not the incentive payment should be reviewed before being granted (to ensure it is consistent with long term value for money) or whether we need to consider/assess when the payments should be made.

3.13. The strength of financial incentive will depend on:

- confidence in the clarity of the output;
- the level of controllability the SO has in delivering the output;
- confidence in the accuracy and reliability of the information used to measure performance; and
- the importance stakeholders and customers place on the delivery of the output.

3.14. When making decisions on the design of financial incentives we will take account of the principles used in the RIIO model to set output incentives. We will also be mindful of the benefits of building on existing output schemes. We will take account of interactions between financial output incentive schemes and between the output financial schemes and cost incentive schemes. We will also need to consider when information becomes available during the scheme period and whether stakeholders are more concerned about delivery on average over time or spot performance (e.g. one incident of the system being out of balance).

Monitoring performance

3.15. As part of the development of the output incentive schemes we will need to detail the target level of performance we expect SOs to operate at, taking into account stakeholders' views.

3.16. In the event of persistent failure to deliver outputs we will have at our disposal a backstop threat of using our existing powers to revoke a company licence and/or financial penalty, this will only be used in exceptional circumstances.

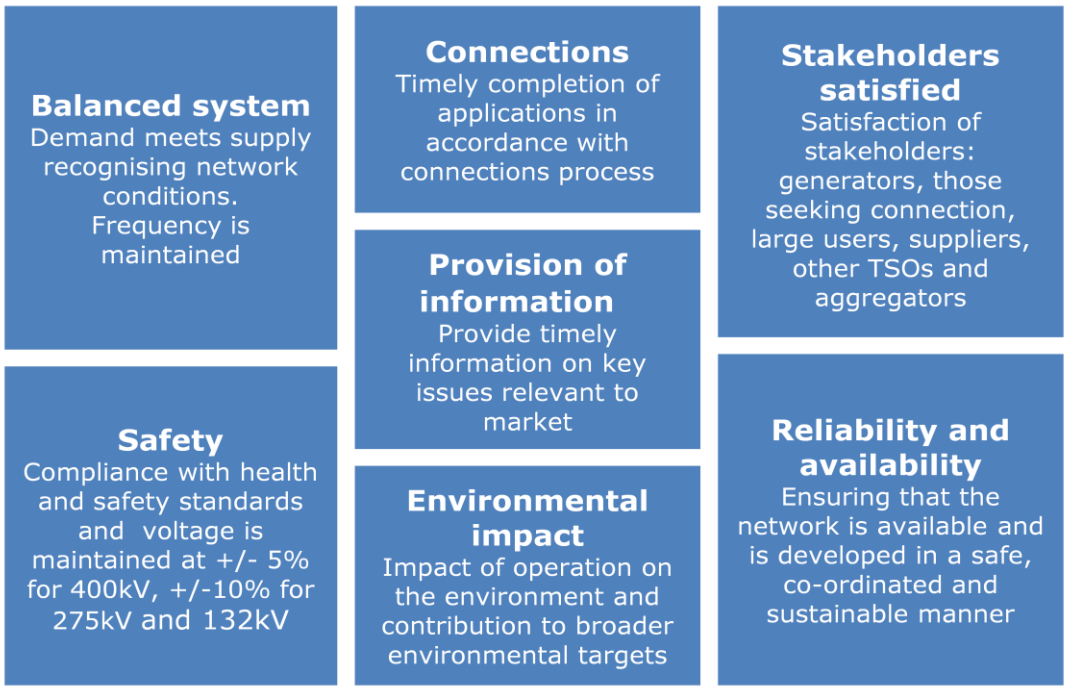
3.17. To facilitate application of the incentives developed for outputs it will be important for us to have a clear understanding of the performance of the SO in delivering against the outputs. Arrangements will need to be implemented to facilitate this monitoring. To ensure that we have a clear understanding of the additional information requirements, we will review the information that we already receive prior to setting new SO incentive schemes.

Electricity SO output incentive schemes

3.18. As detailed above, we have reconsidered the output categories for the electricity SO that we set out in our June document, taking into account the

responses to that document and our ongoing consideration of the current and potential future role of the electricity SO. Based on this, the outputs the electricity SO is expected to deliver from April 2013 will sit in one of the seven output categories shown in Figure 3.2. These output categories will be at the centre of the regulatory framework for the electricity SO.

Figure 3.2: Electricity SO output categories



3.19. A summary of our minded to position on all the electricity SO output incentive schemes by output category is provided in Table 3.1. Table 3.1 also provides our initial views on whether the output incentive scheme should be reputational or financial and on the potential length of the output scheme. Further information in respect of each of these output categories and associated output measures is outlined in Appendix 4.

Table 3.1: Summary of electricity SO outputs and regulatory treatment

Output	Regulatory treatment
Safety	
Work place safety *– to design and operate its network to ensure the safety of the public and its employees*	Covered by legal requirements and captured in RIIO-T1 outputs – no regulatory SO scheme.
Correct system voltage *– to ensure that voltage is maintained at ±5% for 400kV ±10% for 275kV and 132kV lines*	Grid Code requirement, captured by wider HSE legal requirements and captured in RIIO-T1 outputs – no regulatory SO scheme.
Environmental impact	
Broad environmental targets *– to ensure energy companies play a full role in the delivery of a sustainable energy sector*	Reputational SO output incentive scheme, complementing RIIO-T1 environmental outputs.

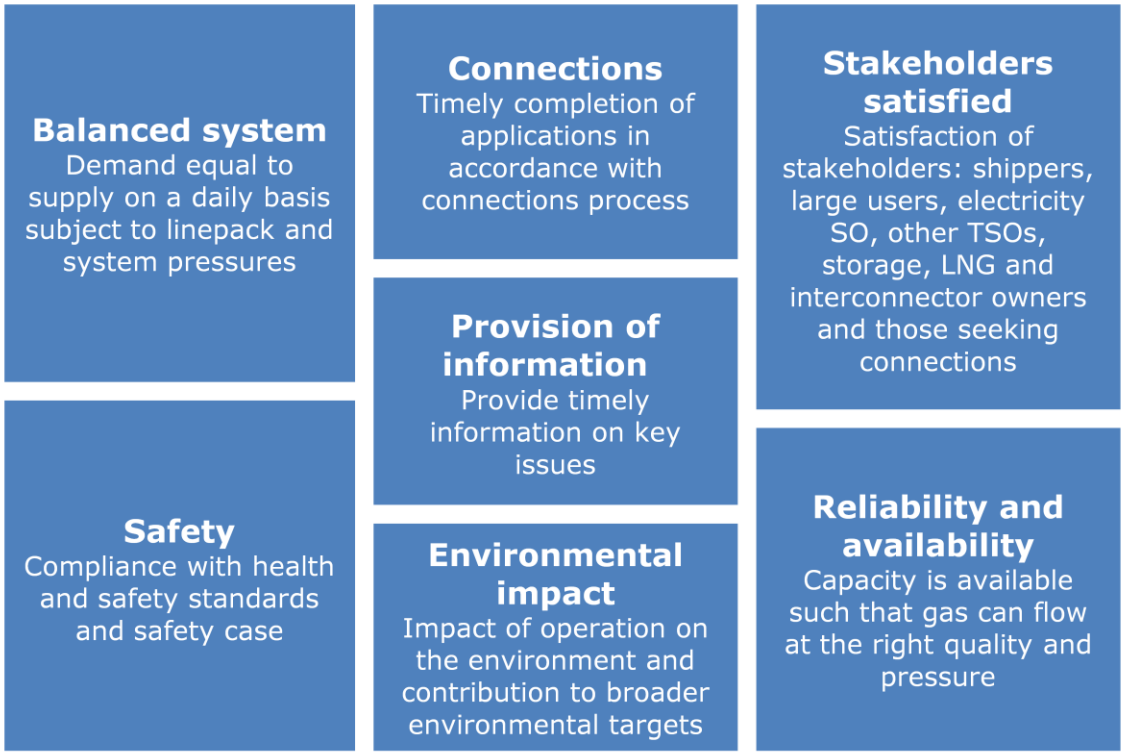
Output	Regulatory treatment
Transmission losses *– to reduce transmission losses when procuring the services it needs to balance the system*	Financial – no output on TOs in RIIO-T1. This output incentive is to be set on a four + four year basis.
Business carbon footprint *– to reduce its business carbon footprint*	SO impact captured in TO output in RIIO-T1. No SO regulatory output 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)*	Covered by licence and the CUSC. It is also captured under RIIO-T1 through the connections output. No SO regulatory output scheme.
Reliability and availability	
Management of processes and procedures *– to play an important, proactive and innovative role*	Reputational SO output, no output on TOs in RIIO-T1. This output incentive is to be set for eight years.
Interactions with TO's, especially with respect to network investment *– to develop a policy statement that demonstrates how ongoing interactions between the SO and TOs (and TSOs) will occur*	Reputational incentive – the SO and TO will be jointly responsible for delivery. Requirement to produce policy statement that details interactions. We will further consider the need for specific incentives to promote coordination in network investment decisions.
Stakeholders satisfied	
Stakeholder survey *– to assess customer/stakeholder views of the SO's performance*	Financial incentive under RIIO-T1. We propose the SO be subject to a similar stakeholder satisfaction incentive to be set for eight years.
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 (± 1% 50Hz save in abnormal or exceptional circumstances)*	Reputational SO output incentive scheme in respect of demand meeting supply. Requirement to produce report that details any frequency deviations outside of limits. Consider how the SO can be required/encouraged to further explore and develop innovative solutions to balancing (e.g. storage, DSR). This output incentive is to be set for eight years.
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*	Legal requirements on the SO to produce information – no regulatory SO scheme.
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 term*	Financial SO output incentive scheme, no output on TOs in RIIO-T1. This output incentive is to be set on a four + four year basis.

Gas SO output incentive schemes

3.20. Based on our further analysis since the publication of our June document, the outputs that the gas SO is expected to deliver will sit in one of the seven output categories shown in Figure 3.3. Taken together these categories reflect the broad role that the gas SO plays in delivering the objective of the gas SO regulatory framework.

3.21. Importantly, we recognise that there are areas where the SO's and TO's roles overlap and therefore they have the same outputs. In the case of gas, where the SO and TO are jointly owned, the key is to specify a set of outputs that capture everything we want NGG to deliver in its role as SO and TO. It is then a secondary, although still important, question whether the output best sits in the SO or RIIO-T1 regulatory framework. The linkages between SO and TO frameworks are already strong given the SO internal cost price control is covered by RIIO-T1 and the internal cost allowances make an important contribution to the delivery of the SO external function. A key part of determining both the SO output incentives and the internal costs price control will be in ensuring NGG achieves value for money in delivering the SO outputs.

Figure 3.3: Gas SO output categories



3.22. In Appendix 5, we provide further information in respect of each of these output categories and provide a view on the associated output measures and incentives. This is consistent with the RIIO-T1 Strategy Decision on TO outputs. Where relevant we also discuss where there are common or related outputs on the SO and the TO. We provide a summary of our views on the regulatory treatment of the SO outputs in Table 3.2.

Table 3.2: Summary of gas SO outputs and regulatory treatment

Output	Regulatory treatment
Safety	
Work place safety *- to operate its network to ensure the safety of the public and its employees*	Covered by legal requirements and captured by RIIO-T1 outputs – no regulatory SO scheme.
Meet Operating Margins requirements *- to ensure that Operating Margins are purchased to meet Safety Case requirements* *- to work with potential new providers of OM in order to facilitate additional providers*	Meeting Safety Case requirements captured by wider HSE legal requirements – no regulatory SO scheme. Keep existing licence requirement to promote competition, reinstate reporting requirements – reputational incentive in SO regulatory framework. This output incentive is to be set for eight years.
Environmental impact	
Broad environmental output *- to ensure that energy companies play a full role in the delivery of a sustainable energy sector*	Reputational incentive in RIIO-T1 environmental outputs relating to both SO and TO contribution. No additional SO scheme.
Reduction in venting emissions *- to consider how it operates its system to reduce emissions, also potential to introduce alternatives to venting*	Financial – no output on TOs in RIIO-T1. This output incentive is to be set for eight years.
Connections	
Ensure efficient and timely connections *- to fulfil its obligations regarding a connections process that needs to be put in place*	Financial incentive to deal with all connection applications in a timely manner in conjunction with the TO. This output incentive is to be set for eight years.
Reliability and availability	
Make capacity available at entry and exit points to meet customer requirements *- to ensure capacity is made available as required and in the most efficient way* *- to have in place and adhere to a methodology statement that details how it chooses between the different options (e.g. buy-back, invest) it has in respect of making capacity available*	Incentive under RIIO-T1 reflecting existing obligations and commercial arrangements.
Stakeholders satisfied	
Stakeholder survey *- to ensure that NGG's stakeholder survey includes questions relating to NGG's role as system operator*	Financial incentive in RIIO-T1 covers both SO and TO roles – no additional output incentive scheme in SO regulatory framework.
Balanced system	
Supply = demand *- to ensure that supply and demand are equal on a daily basis subject to pressure and linepack requirements*	No SO regulatory output scheme.
Minimise change in linepack	Financial incentive (as current). This output

Output	Regulatory treatment
- to ensure that the change between each end of day linepack is kept to a minimum	incentive is to be set for eight years.
Minimise impact on On the Day Commodity Market *- to ensure that when NGG enters the OCM it minimises its impact on the market by trading close to the market price*	Financial incentive (as current). Note that we are also considering a cost minimisation incentive in respect of gas balancing, this is discussed further in Chapter 4. This output incentive is to be set for eight years.
Unaccounted for gas *- to continue to explore the drivers of Unaccounted for Gas* *- should current ongoing work to understand the drivers of UAG highlight specific outputs for the gas SO*	Reputational incentive to investigate drivers of UAG (as in 2012 Final Proposals). The duration of this output incentive is yet to be determined. Potential new incentive dependent on progress with current investigation work. The duration of this output incentive is yet to be determined.
Provision of information	
Availability and timeliness of information on website *- to ensure that the SO publishes information that enables market participants to operate in the gas market*	Current financial incentive to become reputational only. This output incentive is to be set for eight years.
Accuracy of demand forecasts *- to ensure that the demand forecasts that NGG publishes are as accurate as possible*	Continuation of current financial incentive in current form. This output incentive is to be set for eight years.
Publication of forward looking market information *- to publish information to the market that assists participants with understanding future developments* *- to publish statements that assist market participants to understand how NGG as SO undertakes its role* *- to ensure that actions undertake by the SO or TO that affect the other party are transparent*	No SO output scheme.

4. Cost incentives and SO-TO interactions

This chapter explains the principles and processes that we use to define and design cost incentive schemes to encourage the SOs to seek out ways of delivering outputs at value for money. We also provide our initial views on the cost incentive schemes that will be in place for the gas and electricity SOs from April 2013. We also consider whether additional mechanisms are needed to ensure the SO has sufficient incentive to take account of SO-TO interactions on an ongoing basis.

Question 10: Do you agree that the cost incentives we are minded to apply are appropriate? Please explain your reasoning.
Question 11: Do you agree that the parameters (scheme length, sharing factors etc.) we have proposed for the cost incentives are appropriate? Please explain your reasoning.
Question 12: Do you agree with our proposals to introduce a payment mechanism to encourage efficient SO-TO interactions?

Cost incentive schemes – process and principles

4.1. Consistent with the RIIO model, a core objective of the SO regulatory framework from April 2013 is that the SOs should be encouraged to deliver the outputs set out in Chapter 3 at value for money for existing and future consumers. It is important that outputs are delivered. However, it cannot be output delivery at any expense. The SOs must continue to provide an efficient and economic system and the regulatory framework will need to encourage the SOs to minimise costs over time. Our focus here is on SO external costs, with the incentive to minimise SO internal costs provided by the separate price control on these costs.

4.2. We continue to believe that the most effective way of encouraging the SOs to be efficient is through the use of cost incentive schemes. As we do now, we will set a cost target and sharing factor for these schemes. What will potentially change is the length of scheme, the process by which we determine the cost target and sharing factor, the scale of the transparency, and the principles used to determine whether and how to make use of uncertainty mechanisms including caps and floors.

4.3. For each of the gas and electricity sectors we will identify the main categories of external SO costs and consider whether it is appropriate to have a cost minimisation incentive for each cost category. Where a cost is determined by factors completely outside the SO's control, we would not expect to have an incentive scheme in place. For other costs, which are entirely or partially in the company's control, an incentive scheme to encourage the company to manage its business efficiently and effectively to minimise the costs is desirable. We expect that the cost categories we will be incentivising from April 2013 will be broadly similar to those that have been incentivised in the past.

4.4. We are also aware that one of the purposes of setting longer term incentive schemes is to encourage efficient long term decision making by the SOs. We need to ensure the incentive to make efficient long term decisions is maintained towards the end of the eight year period, even where the benefits of those decisions (in terms of cost savings) will accrue after the end of this period. We will consider if there is a need to introduce measures to ensure the incentive to make appropriate longer term

decisions is maintained throughout the full period. An example of this would be to commit to allowing the SO to share in the benefits of cost savings accruing after the eight year period.

Packaging cost categories

4.5. Once we have identified which cost categories we want to incentivise, we need to consider whether to have a separate scheme for each cost category or whether to package categories together. The potential advantages and disadvantages of packaging costs into one incentive scheme were discussed in our June 2011 consultation. Building on that discussion, and responses to the consultation, we propose to combine costs where there are strong interactions between them; where it is difficult to identify and measure separate cost categories or where individual cost items are small in value and there is little to be lost from streamlining the set of incentive schemes.

4.6. On the contrary, we will not combine costs if there is a risk of distorting managerial focus, particularly if there is a cost category that we want the management to put significant effort into. Where there is a concern with combining costs into one incentive scheme we will consider whether similar benefits to packaging can arise with multiple schemes with the same incentive power (length, sharing factor and uncertainty mechanisms).

Cost targets

4.7. We will work with the SOs to develop the methodology for setting the cost targets in each cost incentive scheme. When making decisions, we intend to take account of the principles set out below.

4.8. The cost target should relate to controllable costs. This could be done by identifying controllable costs ex ante and using these to set the target. Where this is not possible we would aim to develop methodologies for setting the cost target that adjust the target for factors outside the SO's control before determining the scale of rewards and penalties.

4.9. We will use existing methodologies for determining cost targets where we, and respondents to our consultations, have not identified any significant concern with the approach taken.

4.10. Our assessment of appropriate cost targets will take account of the baselines of the TO business plans, and the internal cost allowances for the SOs. For example, if the TO plan suggests that there will be significant additional capacity on the Scottish electricity transmission system by, for example, 2017, we will reflect this in our assessment of SO costs.

4.11. Where the models used to forecast cost targets reflect historic relationships we need to monitor whether these relationships remain stable over time and update them as appropriate. We will endeavour to balance the need to have realistic cost targets with the need to maintain powerful incentives for cost reduction. We will do this by considering whether and how the link between actual costs and target updating can be managed.

Sharing factors

4.12. We want to provide the SO with powerful incentives to minimise external costs over the longer term. For each cost incentive scheme the power of the incentive will depend on the size of the sharing factor and any uncertainty mechanisms that affect the extent to which the sharing factor is applied.

4.13. Consistent with the approach to efficiency incentives in the RIIO model we propose to set an upfront fixed symmetric sharing factor for each cost incentive scheme. With this approach the SO will know the value of each £1 saved relative to target and the cost associated with each £1 above target. The sharing factor may be the same for the entire scheme length or there may be a mechanism in place to allow for it to be adjusted during the period. When considering which approach is best we will take account of the scheme length and the importance of transparency and commitment.

4.14. Where a cost category involves strong SO-TO interactions, either directly or via interactions with common outputs, we would expect to use the same sharing factor as is used in the final RIIO-T1 proposals. This is needed to remove existing distortions arising from misaligned incentives. We are working with a range of 40 to 50 per cent for the TOs at present, with the final value determined through the application of the Information Quality Incentive (IQI) scheme. If we consider there are downsides of a sharing factor of this scale in the SO cost schemes we will decide if they can be managed through uncertainty mechanisms.

4.15. When considering the appropriate scale of the sharing factor for cost categories that do not involve significant SO-TO interactions, we will take account of the following principles.

4.16. The sharing factor will be higher where we think there is scope for significant efficiency improvement in a particular cost area. On the contrary, the sharing factor will be lower where we consider a high powered scheme would result in too much risk on the SO and where we are confident that this is consistent with the objectives of the regulatory framework.

4.17. The scale of the sharing factor will also depend on the extent to which we are confident that the cost target is controllable. If it is, then higher sharing factors are likely to be appropriate. If not, it may be preferable to have lower sharing factors.

4.18. The relative scale of the sharing factors across cost incentive schemes, and between the cost schemes and the output incentive schemes, should ensure that the regulatory framework does not distort decisions relating to reducing one cost rather than another, or reducing costs instead of delivering outputs.

4.19. Any significant increase in incentive power relative to existing schemes must be carefully considered, with particular focus on implications for risk and long term value for money. We will consider whether there is a need to transition to a higher powered incentive within the scheme period where the step change from existing schemes is significant.

4.20. As the sharing factor is a fixed proportion it does not vary with the length of time between when a cost saving (or cost increase) is made and when the sharing factor is applied. We expect to apply the sharing factor automatically, without any

review of the cause or driver of any cost increase or decrease. We will consider what the appropriate timing for applying the cost sharing factor is, taking account of the charging processes and the approach adopted in RIIO[9]. This decision will affect the impact of the sharing factor on the profile of cashflow but does not change the net present value of the benefit (cost) of outperformance (underperformance) as the percentage share does not change.

Cost incentive schemes

4.21. Taking account of the process and principles set out above we have developed our preliminary views on the set of electricity and gas cost incentive schemes to be applied from April 2013. We will continue to develop the details of these schemes with the SOs and would welcome comments and views on all aspects of scheme design.

Electricity cost incentive schemes

4.22. The external costs that NGET incurs in its role as SO include the costs associated with:

- buying and selling of electricity in the Balancing Mechanism;
- entering into balancing services contracts; and
- entering into contracts for ancillary services[10].

4.23. From April 2013, we want to incentivise NGET as SO to continue to minimise these costs while delivering the electricity SO outputs. Our current view is that we should continue with the cost categories currently incentivised – see Table 4.1. We have not identified any other electricity SO cost categories that need to be covered by a separate cost incentive scheme or incorporated into the bundled scheme. We consider that the scope and nature of this cost incentive has been carefully considered (and improved) as part of the process associated with setting of the electricity SO incentive scheme to apply from April 2011[11].

4.24. However, we note that as part of the setting of the current two year electricity SO cost incentive we required NGET to identify and undertake further improvements to its methodology, including its modelling. We are also monitoring the current scheme to ensure that it operating as expected. We will continue to work with NGET to refine its cost methodology over the coming months.

[9] In the RIIO model we intend to apply the efficiency sharing factor annually, with a two year lag so that the factor is applied to actual audited cost data.
[10] The electricity SO incurs costs in order to buy and sell electricity such that the system remains in balance; resolve transmission constraints; procure reserve and frequency response, such that generation and demand is able to respond to unexpected changes in demand and supply; procure reactive power, such that voltage on the system remains within prescribed limits; and ensure Black Start services are available, to enable the system to recover from a partial shutdown.
[11] Under this approach, all the various cost relationships are set ex ante prior to the start of the scheme. All inputs determined to be ex post inputs are then updated on a monthly basis, and combined with ex ante variables during the scheme period to determine the target level of costs that NGET is incentivised against. Thus, while an estimate of the cost against which NGET is incentivised will be produced on a monthly basis, the final cost target will not be known until the end of the scheme.

Table 4.1: Electricity cost schemes

	Scheme length	Cost target methodology	Sharing factor
Total balancing costs (bundled)	4+4	As per now, with refinements of cost drivers and modelling	40–50%

4.25. As Table 4.1 outlines, we are proposing to extend the length of the scheme from the current two years to a four year + four year scheme. We consider the new methodology is suitable for use in schemes of greater duration than the current two years. That said, we recognise that the models underpinning this methodology remain relatively new and that further improvements may be identified over time. To address this risk we consider that having a four year + four year cost incentive scheme is appropriate.

4.26. This means that we would commit to the overarching methodology for eight years but would re-examine the underlying models and data used. The expectation is that the existing models and data sources be retained unless there had been a significant change in circumstances or we found that there were serious unintended consequences arising from their continued use. For example, we may find that previously identified relationships between variables had changed or that there was a better source of data available.

4.27. We consider that this approach would be beneficial for both the SO and for consumers, as it would bring certainty as to the overall approach while permitting appropriate refinements of the underlying models and/or data.

4.28. We want to continue to provide the electricity SO with a strong incentive to reduce external balancing costs, particularly given the challenges associated with the increase in intermittent generation. As there are close interactions with the TO we consider that increasing the sharing factors to 40 to 50 per cent to align with RIIO-T1 is appropriate. This is an increase on the 25 per cent sharing factors that are currently used.

4.29. We consider it appropriate to increase the sharing factors in this way. The methodology for setting the target ensures that performance relates to costs within the company's control. Also the current scheme will have had sufficient time to fully demonstrate its veracity, further refinements to the cost methodology should have been tested and be ready for implementation. We are therefore of the view that the increased sharing factor provides significant benefits by allowing better alignment with the TO over a longer period. It also appropriately balances the risks associated with the methodology while maintaining a sufficient robust incentive for NGET to improve its performance.

Gas cost incentive schemes

4.30. The external costs that NGG incurs in its role as gas system operator relate to its role as NTS Shrinkage manager[12], requirements relating to the availability and utilisation of Operating Margins[13] and daily balancing requirements subject to linepack and system pressures[14]. From April 2013 we want to incentivise NGG to continue to minimise these costs whilst delivering the gas SO outputs.

4.31. Our present view is that we should continue with the cost categories currently incentivised (Shrinkage costs and Operating Margins costs). As set out in Chapter 3 we are also considering whether to introduce an incentive on NGG that is focused on minimising balancing costs. Such an incentive could either replace, or be in addition to, the current price component of the residual balancing incentive. We would welcome views on this and in particular welcome comments on what the different impact on the market would be of any cost minimisation scheme compared to the current output scheme, which is designed to incentivise the SO to have a minimal impact on the market.

4.32. We provide an overview of our initial view for the two gas cost incentive schemes in Table 4.2. We discuss the design further in Appendix 6.

Table 4.2: Gas cost schemes

	Scheme length	Cost target methodology	Sharing factor
Shrinkage cost (bundled)[15]	8 years	As now, volume forecast[16] multiplied by reference prices	40-50%
OM cost (bundled, with utilisation costs potentially carved out above a certain value)[17]	8 years	To be determined, e.g. target could reflect past tender prices for OM with an efficiency factor applied	20%
Potential Balancing cost	To be determined		

4.33. We have considered whether any of these cost schemes could be packaged together. Taking account of responses to the June consultation we have decided that there is little interaction between them and hence the benefits of any further

[12] The Shrinkage costs relate to Compressor Fuel Use (CFU), Calorific Value (CV) Shrinkage and Unaccounted for Gas (UAG).
[13] These costs include capacity fees, gas delivery service fees, standby fees and costs associated with reprofiling, withdrawing and injecting gas into and out of storage.
[14] Costs incurred relate to the buying and selling of gas on the On the Day Commodity Market (OCM).
[15] The shrinkage cost scheme will, as now, bundle Compressor Fuel Use costs, Calorific Value Shrinkage costs and Unaccounted for Gas costs.
[16] The volume target methodology is set in advance based on separate forecasts for each of the three elements, a forecast CFU volume (adjusted by outturn St Fergus flows), a forecast CV Shrinkage volume (excluding low probability high cost offtakes) and outturn UAG volumes (UAG volumes are currently separately incentivised).
[17] The scheme bundles availability and utilisation costs.

bundling would be limited. At the same time, each cost category is important in its own right and we want to maintain management focus and effort on each area. It is also important that we, and stakeholders, observe and monitor performance in each area. We have therefore decided against further bundling at this stage. Outputs and aligned incentive rates across the cost categories should manage any concerns that the SO will attempt to perform better in one area at the expense of another. We will keep the case for bundling the cost schemes under review as we develop the schemes, this will be particularly important if we do decide to implement a balancing cost minimisation scheme, as we will need to ensure that there are no interactions with the Shrinkage scheme that we would need to take into account.

Taking account of SO-TO interactions

4.34. In Chapter 2 we emphasised that we expect the gas and electricity SOs to take account of SO-TO interactions when making decisions about output delivery at long term value for money. We have designed the SO regulatory package to be consistent with the framework used to regulate the TOs (RIIO-T1).

4.35. We need to consider whether aligned and stronger output and cost incentives, and longer term schemes, will be sufficient to encourage the SO to take account of SO-TO interactions on an ongoing basis. Where there is common ownership of the SO and TO we expect that the proposals should be sufficient. We intend to reinforce the aligned incentives by having a transparency requirement on NGG and NGET to demonstrate whether and how the interactions have been taken into account.

4.36. In electricity, where there is separate ownership of the Scottish TOs and the GBSO, aligned output and cost incentives are necessary but not sufficient to encourage joined up consideration of long term consumer costs. This is because the benefits of a cost saving will accrue to one company and any additional costs incurred to deliver the savings will be borne by another. The regulatory framework needs to do more to effectively facilitate the intention of the aligned incentives.

- A mechanism is needed to ensure that the GBSO engages in an effective and consistent manner with the three TOs on an ongoing basis, encouraging better communication and information sharing where necessary.
- The GBSO will need to be able to make payments to the Scottish TOs, under separate ownership, to provide compensation to the TO for changing its short term behaviour (e.g. changing outage planning).

4.37. We set out our proposals on short term behavioural interactions here. We will have a dedicated project considering further whether specific incentives are required to ensure coordination between the SO, the TOs, the Offshore Transmission Operators (OFTOs) and interconnectors developers on investment planning.

4.38. With respect to short term behavioural interactions, we propose that the electricity GBSO should pay the Scottish TOs compensation if the Scottish TOs change their behaviour to deliver overall cost savings to consumers. This is an extension of the existing provisions in the SO-TO Code (STC) for the SO to request changes by the TO in relation to outage plans and to pay the TO to do this. We will consider further whether we need to put a specific licence requirement on the SO to only put forward reasonable requests to the TO. We will consider whether the TO needs a requirement to have due regard to these requests and to respond to them in

an effective manner and in a timely way when we are developing the licence requirement for the TO baseline performance and policy on network availability.

4.39. We discussed this idea of a payment mechanism in our June consultation and set out the benefits of the mechanism. Since then we have developed our thinking on how the payment mechanism would work and considered further the extent to which Ofgem would need to be involved.

4.40. We would expect the SO to make use of the payment mechanism where it identifies during the TO's price control period that there could be SO cost savings if the TO changed its behaviour, for example by changing outage planning. The SO would ask the TO to make the changes and would offer payment to compensate the TO for the extra cost involved. The payment would be expected to cover efficiently incurred TO costs and any incentive payment to encourage the TO to make the changes. With aligned output and cost efficiency incentive schemes these requests would only be made where they would result in total cost savings for consumers.

4.41. SO charges would be used to recover SO costs including the payment to the TO and any incentive payment for the reduction in SO costs relative to target. The payment to the TO and the TO costs incurred as a result of the SO request would sit outside of the TO's price control. We would intend to commit to not adjust the SO's cost target during the scheme period to reflect the TO changes, allowing the SO to reap the incentive scheme benefits of requesting the change in the first place.

4.42. Ordinarily the SO would only be able to ask for changes that did not put the delivery of TO baseline outputs at risk. There may be cases where the SO and TO consider that seeking a derogation from an output requirement is the value for money solution. In these cases we would expect the TO to make a derogation request to Ofgem, potentially with supporting evidence from the SO where it is a joined up decision that is driving the request.

4.43. The payment mechanism would not be used for changes relating to SO-TO interactions that are identified at the time of the TO's price control review. Such changes would be incorporated directly into the TO price control, reflected in the SO incentive schemes and paid for by consumers through transmission charges.

4.44. If the SO wanted to request a change in behaviour that would result in a significant change in the TOs outputs during the price control period we would expect this to be considered as part of the potential mid period review of TO outputs under RIIO-T1. In this case the SO-TO interactions would be reflected in an update to the TO price control, and any knock-on adjustment to the SO incentive schemes. Payments from the SO to the TO would not be envisaged.

4.45. We want the SOs to be proactive in identifying how best to work with the TOs to deliver SO outputs at long term value for money. We envisage that the payments from the GBSO to the Scottish TOs will take the form of bilateral contracts and Ofgem's involvement in this area would be limited. We would expect the SO to inform us of any such bilateral contracts and associated payments and to provide assurance that the proposed changes are in the interest of existing and future consumers. This would be part of their wider requirement to demonstrate that they are considering SO-TO interactions on an ongoing basis.

4.46. We would not intend to be involved with discussions on the detail of the contract conditions. We would be available as a port of recourse if the TO refuses to respond effectively to a legitimate SO request or if the TO considers the payment proposed by the SO to not be sufficient to cover efficiently incurred TO costs plus an incentive payment. Where the costs involved were significant or a request was made for a derogation from an output requirement we would reserve the option to assess the efficiency of the proposal in more detail. We may also undertake surprise spot checks of the efficiency of the agreements in these bilateral contracts.

4.47. The use of payments from the SO to the TO may not always be appropriate.

- The SO may identify an area of interaction where the cost savings are significant and hence the payment to the TO would be large. The costs for the SO could be greater than if the costs were financed by customers through the TO's price control. This may affect the extent to which a joined up decision is considered to be cost effective by the SO, even though with alternative financing arrangements it may result in lower costs for consumers.
- If the benefits of the TO changing its behaviour accrue over the long term the SO may not propose the changes to the TO. The benefits in terms of SO cost savings could accrue for longer than the length of the incentive scheme, and in some cases the benefits may not accrue until after the current scheme period. In these situations the SO would be concerned that in the next and future periods the cost targets would be reduced to reflect the new TO baseline and it would not benefit from the anticipated efficiency savings. Again, the SO would not have an incentive to pursue a change from the TO, even if it would result in lower costs for consumers.

4.48. In these cases we would need to consider further, on a case by case basis, how best to incorporate a proposal on SO-TO interactions across the SO and TO regulatory frameworks. We would not envisage the SO making a payment to the TO. We would need to consider how best to share the benefits of any cost savings between the SO and TO so that both have an incentive to consider larger and longer term changes. We expect the situations in which we need to consider these types of changes during the regulatory period (rather than at the time of the TO price control review) will be limited. We therefore think it is appropriate to consider them on a case-by-case basis rather than complicate the payment mechanism described earlier.

5. Risk and uncertainty mechanisms

This chapter sets out our approach to sharing risk between the SO and customers including our approach to using uncertainty mechanisms within the regulatory framework.

Question 13: Do you agree with the factors we propose to consider when deciding on the role of uncertainty mechanisms?
Question 14: Do you agree with our initial view that the caps and floors on SO incentive payments could undermine the SO taking long term decisions and could undermine alignment of incentives between the SO and TO?
Question 15: Are there any areas where you think specific uncertainty mechanisms should be introduced into the regulatory framework?

Uncertainty within the regulatory framework

5.1. All businesses operate in an environment with inherently uncertain outcomes. These uncertainties represent potential risks for the business to manage. In a competitive market companies will be able to reflect, to an extent, the risks they face through a risk premium in prices. In the context of price controls with an asset base these risks are normally recognised in higher allowed financing costs (and hence higher charges).

5.2. In the case of the SO, the output and cost incentive schemes will determine the balance of risk between the SO and consumers. The costs of operating the gas and electricity systems are passed on to customers through various charges. These charges are net of any incentive reward/penalty on the SO resulting from its performance against the incentive schemes. The incentive reward/penalty mean the SO bears some of the financial risk arising from the uncertainties it faces. How these schemes are designed determines the extent of the risk the SO faces.

5.3. The treatment of uncertainty within the regulatory framework has the potential to enhance or undermine the achievement of its objectives. The treatment of uncertainty can influence the potential for windfall gains and losses[18] or undermine incentives on the SO to reduce its costs. Our approach to uncertainty is consistent with the RIIO principles and the approach being applied in RIIO-T1 and RIIO-GD1. However, we acknowledge the SO is a very different type of business to a network company and the application of these principles must take into account its specific circumstances. In particular, unlike the TO, the SO does not own and maintain a large network and faces uncertainty from changes in wholesale prices.

5.4. The SO faces a number of uncertainties in fulfilling its role. Broadly these uncertainties can be placed into one of four categories: price; volume; political/regulatory risk; and uncertainty emanating from the SO's operating environment (other than that linked to price or volume risk). We describe these uncertainties and give examples of how they impact the SO in Table 5.1 below.

[18] By windfall gains/losses we mean very high/low profits that might be a result of god/bad luck more than good/bad management.

Table 5.1: Sources of SO risk

Broad category of uncertainty	Description	Examples
Price	Price uncertainty results from changes in market prices. Whenever the SO is required to purchase energy or other services it is potentially exposed to price risk.	• Procurement of balancing and other services, e.g. black start. • Procurement of shrinkage gas.
Volume	Volume uncertainty is a result of either demand or supply or both being different from expected. It is wider than uncertainty about aggregate supply and demand uncertainty. It also includes uncertainty about location, timing and rate of change of supply and demand.	• Real time uncertainty about balance of demand and supply, particularly acute during periods of substantial swings in demand or supply. • Increase in wind output with resulting intermittency will exacerbate supply uncertainty. This impacts gas as well as electricity as CCGT production is potential flexible reserve for wind. • Procurement of shrinkage gas.
Political/Regulatory	Legislative or regulatory changes can affect the role of the SO or impact how it fulfils its role.	• EMR, notably the decision that the SO will deliver the capacity mechanism and FiT CfDs. • The gas SCR draft policy decision recommended consideration of further interventions (beyond proposed cash out reform) to enhance gas security of supply.
Operating environment	Uncertainty from operating environment outside of other risk categories.	• Storms or floods could, for example, cause widespread system failure that could trigger the use of black start service (in electricity) or operating margins (in gas).

5.5. The regulatory regime should not protect companies from all uncertainty. We would expect the SOs to be exposed to risk emanating from uncertainties that the SO can meaningfully manage, influence or otherwise mitigate the impact of. Leaving at least some of the risk emanating from the manageable uncertainties it faces means that the SO will have an incentive to actively manage the impact on behalf of consumers. The extent of the risk the SO is required to manage should be consistent with the Authority's statutory duties. In particular, there should be no unnecessary risk around delivery of the SO outputs and the financial viability of the SO as an efficiently operating standalone entity should not be put at risk.

Design of regulatory framework and SO risk

5.6. The design of the regulatory regime will determine the extent to which the risk emanating from these uncertainties is shared between the SO and consumers. Almost all aspects of the regime can have an effect on the balance of risk. Some examples of how the design of the regulatory framework can influence SO risk are in Table 5.2.

Table 5.2: Aspects of regulatory framework and SO risk

Aspect of regulatory framework	Potential impact on SO risk
Length of scheme (core)	Broadly the longer the parameters of an incentive scheme are fixed for the greater the risk borne by the SO. This risk arises from the fact that it is more difficult to forecast, and consequently set meaningful targets, for longer periods of time.
Sharing factor (core)	Applying a larger sharing factor to output and cost schemes would expose the SO to the financial consequences of uncertainty to a greater extent. Similarly, the SO can be shielded from these consequences by the application of a lower sharing factor.
Output incentives (core)	The extent and nature of the output incentives can mean the overall financial performance of the SO is more dependent on its own performance and the uncertainties it faces.
Methodology for setting cost and output targets (core)	The degree to which the targets relate to controllable factors, the quality of information available, the reliability of modelling and other techniques that can be used in target setting are factors which can influence the robustness of targets. SO risk relating to performance against target will be related to the robustness of the target.
Caps and floors (risk mitigation)	The use of caps and floors on penalties or rewards under the regulatory framework will limit the exposure of the SO to the uncertainties it faces.
Mid period outputs review (risk mitigation)	To be triggered if there is a substantive change in the outputs a company is required to deliver. It is not intended to be applied automatically or to look at all aspects of the regulatory settlement.
Specific uncertainty mechanisms (risk mitigation)	Uncertainty mechanisms are methods of adjusting cost and output targets within period (outside any mid period review). These can be mechanisms that are trigged by specific factors that are identified in advance (e.g. a known legislative change). These are typically employed where there are uncertainties outside of the entity's control or that are very difficult to accommodate in forward looking targets.
General uncertainty mechanisms (risk mitigation)	Alternatively uncertainty mechanism may be more general mechanisms that allow targets to be reassessed in the event of uncertainty that is not known in advance but which will have a fundamental impact on the regulatory framework and the targets. An example might be legislative change unknown at the time the regulatory framework was set out.

5.7. The impact of each of the factors set out in Table 5.2 on the risk of the SO can be considered in isolation but the key issue is the effect on the overall balance of risk between the SO and the customer. Whilst changes to one of the scheme parameters might increase the risk of the SO, changes to another may mitigate this. For example, increasing the length of the SO schemes could increase the risk of the SO. However, some of this risk might be mitigated or offset by introducing uncertainty mechanism or a mid period review.

5.8. As we develop the design of the output and cost incentive schemes we will in the first instance consider the impact on the level of risk sharing between the SO and consumers in the absence of any risk mitigation mechanisms. If we consider that the level of risk that the SO is exposed to is too high we will consider whether it is appropriate to make changes to the design of the incentive schemes themselves. For example, we could consider whether sharing factors can be changed although we would be less likely to do this where there are interactions with the TO. We will also consider whether there is a role for uncertainty mechanisms linked to specific factors or for more general uncertainty mechanisms.

5.9. We will consider a number of factors when coming to a final view on the role of uncertainty mechanisms and other methods of risk mitigation in the regulatory framework. These include:

- **The implications for the overall risk characteristics of the scheme.** Where the scale of the potential impact of the uncertainty is relatively large there may be a case for adapting the framework to mitigate it.
- **The implications for the incentive properties of the regulatory framework.** When deciding if or how we may adapt the regulatory framework we need to ensure that the SO still retains appropriate incentives to efficiently deliver outputs.
- **Consistency with the overall principles of the regulatory framework.** It is also important that the framework is compatible with the overall principles set out in Chapter 1.
- **The degree of confidence we can have in forward looking targets.** Some uncertainties are more "forecastable" than others, for example where there is a good supply of reliable and relevant data or where there are tried, tested and reliable models that can be applied.
- **The impact on regulatory burden and complexity of the framework**. The introduction of uncertainty mechanisms has the potential to both increase the complexity of the regulatory framework and to reduce its transparency. It is important that any uncertainty mechanisms are considered holistically in light of other mechanisms and the wider regulatory framework.

Dealing with risk and uncertainty – Initial view

5.10. Below we set out our initial views on how we will deal with risk and uncertainty.

- to widen the caps and floors on SO incentive payments;
- to introduce uncertainly mechanisms for specific risks; and
- to introduce a general mechanism to reopen the schemes in extreme unforeseen circumstances or if the regulatory framework is consistently not delivering for customers.

5.11. We consider that narrow caps and floors could undermine the incentive properties of the framework and may not be entirely consistent with its underlying principles. Caps and floors on incentive payments work to limit the SO exposure to risk. However, by limiting the gains or losses to the SO over the period there is also a limit on the incentive that the SO has to manage the risks it faces, possibly even where the risk is one the SO is best placed to manage.

5.12. It is also the case that limiting the potential gains could reduce the SO incentives to make long term decision that require a large upfront cost but that will deliver reductions in the SO costs over a longer time period. This is because the gains the SO can make (in terms of an incentive payment related to its cost savings) are limited by the existence of the regulatory cap.

5.13. In addition the caps and floors could undermine our intention to more closely align the SO and TO incentives. The TOs' exposure to risk is not similarly limited by caps and floors and the trade off between SO and TO costs could be distorted by this difference between the regulatory frameworks.

5.14. We therefore propose to widen or (in some cases) potentially remove the caps and floors on SO cost incentive payments to encourage long term thinking and to achieve alignment with the TO incentives. We would prefer, if possible and necessary, to mitigate SO risk by means of other uncertainly mechanisms which are more compatible with the underlying principles of the framework. However, we recognise that, particularly in the context of this new regulatory framework, caps and floors may have a role to play in achieving the appropriate balance of risk between the SO and customers where this cannot be achieved by other means.

5.15. We will consider introducing uncertainty mechanism to adjust cost and outputs targets for specific risks. Where we deem there is a case for introducing any uncertainty mechanisms we will use the principles for designing these set out in Chapter 11 of the RIIO handbook. We set out some initial thoughts on areas where there make be a case for uncertainty mechanisms below. These are not supposed to be an exhaustive list of areas but rather examples for consideration. If the list of potential uncertainty mechanisms becomes too long we will consider bundling them into fewer mechanisms to reduce the complexity of the framework.

5.16. As is apparent from our discussion of the SO role we consider that over the course of an eight year period there is the potential for changes to the outputs that the SO will be required to deliver, including the possibility of new outputs categories being introduced. Because the SO is operating in a policy environment which is at the moment quite uncertain and also because the proposals for the regulatory framework set out in this document are new we propose to introduce a general uncertainly mechanism that will permit the regulatory framework to be reopened in certain circumstances.

5.17. Examples of this may be unforeseen legislative change or persistent substantial undershooting or overshooting of cost or output targets. We note that we foresee this operating in a different way to the current income adjusting event (IAE) uncertainty mechanism. The current IAE mechanism can be triggered in too many circumstances, potentially undermining the incentive properties of the regulatory framework. This is because the potential threshold at which the IAE mechanism can be triggered is too low and it can be triggered in response to very specific risks that are considered in isolation from the rest of the regulatory framework. We propose that the new overarching mechanism can only be triggered in extreme circumstances and will ensure that we consider all of the cost and output incentives holistically before agreeing that the mechanism can be triggered.

6. Next steps

In this chapter we set out the proposed process for designing the SO cost and output incentive schemes from April 2013.

6.1. We expect NGG and NGET to submit "SO plans" for the external cost incentive schemes by 31 May 2012. In between the publication of this document and the submission of the SO plans we plan to engage extensively with both NGG and NGET to finalise the outstanding policy issues set out in this document, and to provide further guidance to them to assist in the preparation of their plans. We will publish our initial proposals for the SO output and cost incentive schemes from 2013 in summer 2012.

Ofgem Stakeholder Engagement

6.2. We propose to present the views set out in this document and take questions at industry meetings in February 2012. This will be in advance of the deadline for submitting responses to this consultation. We also propose to hold a stakeholder event post publication of our proposals in the summer.

SO Plans

6.3. We expect that the SO plans will focus on the delivery of outputs and cost scheme targets, including exactly how these targets should be measured and, where required, suggested target values. The output and cost targets will need to be supported by evidence including details of any modelling or data that is used. In addition we would expect the plans to show:

- **Links between outputs and costs.** Insofar as is possible, the companies should demonstrate the link between their proposals for SO costs and outputs. This should include both external and internal SO costs.
- **Consideration of the longer term context.** We expect the plans to consider how the environment that the SOs operate in may evolve over the eight year period and beyond and to consider the implications for the proposed output and cost targets. In thinking about the long term context the plans should identify proposals for any specific uncertainty mechanisms consistent with the principles we outline in Chapter 5.
- **Consideration of interactions with other parties.** We expect the plan to show some consideration of interactions with other parties, especially the TOs. We expect that the SOs' plans will outline clear linkages to the TOs' business plans submitted as part of the RIIO-T1 process and provide details of discussions the SOs have had with the TOs in developing their proposals for output and cost targets.
- **Details of any stakeholder engagement.** We would expect the plans to provide details of the views of stakeholders and how they are reflected in the development of the proposed cost and output targets.
- **Consideration of alternative approaches.** We would expect the plans to show that alternative approaches to delivering outputs for setting cost and output targets have been considered.

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 chapter heading and which are replicated below.

1.2. Responses should be received by 27 March 2012 and should be 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 Mathieu Pearson, (Ph: 020 7901 7294), email: mathieu.pearson@ofgem.gov.uk.

CHAPTER: Two

Question 1: Do you consider that we have captured the full role of the SOs going forward?
Question 2: Do you consider that our minded to position on the length of the regulatory framework is appropriate?
Question 3: Do you consider that our proposals regarding SO-TO interactions provide the SOs with sufficient incentive to consider interactions with the TO in a longer term context?

CHAPTER: Three

Question 4: Do you agree with our minded to position on SO outputs and the interactions with SO and TO outputs?

Question 5: Do you agree with our minded to position on the period for which the various outputs and associated incentives will be fixed?
Question 6: Do you agree with our views on incentivising SO outputs?
Question 7: What areas, in addition to DSR, should a broad environmental output cover? What is your view on having a financial (rather than a reputational) incentive on NGET and/or NGG as SOs to encourage them to deliver against a broad environmental output?
Question 8: What is your view on having a financial output incentive on the accuracy of NGET's forecast of wind generation and the timeliness and availability of that information on its website?
Question 9: What is your view on introducing an incentive based on the total cost of NGG's balancing actions? Should such a total cost incentive replace or be in addition to current incentives for NGG to minimise the impact of its balancing actions?

CHAPTER: Four

Question 10: Do you agree that the cost incentives we are minded to apply are appropriate? Please explain your reasoning.
Question 11: Do you agree that the parameters (scheme length, sharing factors etc.) we have proposed for the cost incentives are appropriate? Please explain your reasoning.
Question 12: Do you agree with our proposals to introduce a payment mechanism to encourage efficient SO-TO interactions?

CHAPTER: Five

Question 13: Do you agree with the factors we propose to consider when deciding on the role of uncertainty mechanisms?
Question 14: Do you agree with our initial view that the caps and floors on SO incentive payments could undermine the SO taking long term decisions and could undermine alignment of incentives between the SO and TO?
Question 15: Are there any areas where you think specific uncertainty mechanisms should be introduced into the regulatory framework?

Appendix 2 – June consultation responses

1.1. On 14 June 2011, Ofgem published a consultation document setting out our initial view on the principles for setting the SO regulatory framework from April 2013[19]. We received eight responses to this consultation document[20].

General Principles

1.2. Respondents were broadly supportive of the general principles set out in our consultation document, although one respondent (Npower) considered that Ofgem's initial views did not propose any fundamental change to current incentives.

1.3. National Grid (NG) pointed out the need to consider the interactions between gas and electricity when designing the incentive schemes. Centrica noted that there should not be incentives on tasks already covered by licence obligations. It also noted the need to consider a fair balance of risk and reward and to assess the risk borne by the SO and consumers when setting sharing factors, caps and floors.

Determination of Outputs to be incentivised

1.4. Respondents broadly agreed that Ofgem identified the most relevant outputs. Several respondents suggested additional outputs to those included in our consultation document. Some of the key issues raised by respondents are outlined below.

Electricity outputs

1.5. NG pointed out that National Grid Electricity Transmission (NGET) was already incentivised to minimise energy not supplied via the transmission network reliability incentive. SSE was also concerned about this output creating perverse incentives on NGET acting as an SO and TO.

1.6. Consumer Focus proposed additional incentives to encourage predictability and stability in charging, and accuracy of wind forecasting. EDF suggested that when designing new incentives in electricity (and also in gas), Ofgem should incorporate the opportunities brought by the implementation of smart metering.

Gas outputs

1.7. NG suggested that instead of an output on monitoring inputs and offtakes to and from the NTS to ensure safety, National Grid Gas (NGG) should be incentivised to manage (not just monitor) these inputs and offtakes. Similarly, NG suggested that an output on calculating gas volumes for the different purposes defined in our consultation document (such as reconciliation or shrinkage), should be replaced with an output on the management of these activities.

[19] The June consultation document is available at: www.ofgem.gov.uk/Markets/WhlMkts/EffSystemOps/SystOpIncent/Documents1/SO%20incentives%20from%20April%202013%20Inital%20Views%20Consultation.pdf

[20] Copies of stakeholders' responses are available at: www.ofgem.gov.uk/Pages/MoreInformation.aspx?docid=244&refer=Markets/WhlMkts/EffSystemOps/SystOpIncent

1.8. NG also suggested than an output on data provision should relate to the provision of data on behalf of the GB gas market and not only of the NTS. It also suggested that an output on making capacity available should specify that NGG must make capacity available in line with obligations and contractual rights, and provide incremental capacity when users require it and system risk is manageable. In addition, Centrica noted that there should not be incentives on outputs related to safety since these are covered by licence obligations.

1.9. Most respondents supported an output on maintenance scheduling and noted there are particular concerns about changes to maintenance schedules at short notice. NG mentioned that maintenance scheduling is in many cases coordinated between shippers and NGG, and that an incentive must distinguish between delays caused by NGG and those caused by shippers.

1.10. NG suggested further outputs relating to safety (such as operating compressors within environmental permits, ensuring that capabilities and processes are in place to manage the network effectively, etc.) should be considered. It also suggested an output on network flexibility (although recognising it may be difficult to measure).

1.11. EDF proposed an output on demand forecasting for Non Daily Metered sectors and energy allocation processes. It also suggested considering the impact of climate change on the SO role. E.ON noted that NGG should assist its customer in providing more accurate inputs or considering ways to improve the forecasting accuracy in distribution networks.

1.12. On Unaccounted for Gas, although respondents acknowledged that the current incentive has not led to satisfactory results, there were concerns about the possible effectiveness of a licence obligation to reduce UAG volumes. In respect of information provision, most respondents supported a licence requirement.

1.13. Most respondents agreed that there may be value in placing an incentive on customer satisfaction, although some noted that this output may be difficult to quantify and that any such incentive may be difficult to design. For similar reasons, one respondent questioned whether an incentive on customer satisfaction was appropriate. Also, respondents mentioned that in designing an incentive on customer satisfaction, it was important to identify any overlaps with RIIO-T1.

Packaging outputs into schemes incentivising delivery

1.14. Respondents broadly supported the idea of bundling where there are clear interactions. Most respondents emphasised that bundling has the benefits of ensuring that the most efficient outcome can be promoted where trade-offs exist.

1.15. Several respondents raised the following concerns about bundling:

- a possible loss of transparency;
- the scope for NGET as SO to be over rewarded;
- it might be difficult to implement in practice; and
- without specific outputs and incentives some aspect of the SO activity may receive less focus.

1.16. For the electricity SO, several respondents supported the current bundling arrangements but also noted that for any additional electricity SO outputs, separate incentives should be developed.

1.17. For the gas SO, several respondents recognised the merits of bundling but noted that this depended on incentives being bundled in a way that allowed trade-offs to be made between the different incentives. Several respondents noted that there are less obvious interactions between outputs in gas compared to electricity outputs.

Incentive scheme length

1.18. Most respondents agreed that our initial views captured all the benefits associated with setting long term incentives. In particular, respondents recognised the importance of long term incentives in encouraging efficient investment decisions. However, they also suggested the introduction of uncertainty mechanisms, reopeners and intermediate reviews within the eight year period.

1.19. Four respondents were unconvinced about the benefits of setting long term incentives. Consumer Focus and SSE were particularly concerned about the benefits of long term incentives for electricity when the results of the current methodology are still unproven. E.ON argued that long term incentives would expose shippers and consumers to excessive risks. Npower noted that there is little evidence that long term incentives will deliver value to customers.

1.20. Three respondents supported a year-by-year approach instead of a multi-year one. SSE argued that until the recent changes are proven effective, a year-by-year approach is more appropriate. It also considered that the implementation of the European Network Codes introduces further uncertainties. Npower highlighted the difficulty of forecasting costs for longer periods, which may lead to the application of adjusters or income adjusting events. AEP noted that long term incentive schemes face the risk of caps and floors being hit and the incentive losing its effectiveness.

Achieving better incentive alignment between SO and TO

1.21. Most respondents agreed with the need to align the SOs and TOs incentives that may help reduce costs and provide benefits to customers. However, SSE disagreed with any economic incentive to drive SO-TO interaction and they suggested that if the current level of alignment is not sufficient enough between these parties, an obligation rather than an incentive should be imposed.

1.22. Most respondents, with exception of SSE and E.ON, agreed that there should be a payment mechanism by which the TO can be incentivised to encourage delivery of certain outputs. However, it was also noted that a payment mechanism was more suitable where there was common ownership of the TO and SO relative to where there was different SO and TO ownership. In addition, AEP and Npower noted that considerable work will need to be undertaken to develop an appropriate payment mechanism.

Appendix 3 – SO-TO interactions

See Supplementary Appendicies Document

Appendix 4 – Electricity outputs and output incentives

See Supplementary Appendicies Document

Appendix 5 – Gas outputs and output incentives

See Supplementary Appendicies Document

Appendix 6 – Gas cost incentives

See Supplementary Appendicies Document

Appendix 7 – Glossary

A

Ancillary Services

Mandatory, necessary or commercial services used by the electricity System Operator to manage the system and to meet their license 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 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 Use of System charges (BSUoS)

The daily 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

The ability to start a generating plant without external power supplies.

C

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.

CV Shrinkage

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

D

Demand side response

Demand side response involves electricity and gas consumers varying demand due to changes in the balance between supply and demand, usually in response to prices.

E

Ex Ante / Ex Post Inputs

Ex ante inputs to NGET'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 NGET 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).

European Industrial Emission Directive

The Directive 2010/75/EU on industrial emissions establishes a general framework aimed at preventing and reducing pollution arising from industrial activities. It came into force on 6 January 2011.

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.

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, such as Northern Gas Networks, are licensed by the Gas and Electricity Markets Authority to transport gas to consumers.

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

Incentive rate (efficiency)

The percentage of underspends/overspends against expenditure allowed at the price control review that is kept by the company responsible. The remaining savings/losses are passed through to consumers.

Interconnector

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

L

Licence conditions (obligations)

An obligation 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

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 of only 1 in 365 days that total demand will not be able to be met.

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 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)

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.

Network users

Companies along the gas and electricity supply chain (i.e. producers/generators, transmission and distribution networks, and energy suppliers).

O

On the day Commodity Market (OCM)

Enables anonymous financially cleared on the day trading between market participants.

OFTO

Offshore Transmission Owner.

Operating Margins (OM) (in gas)

Gas used to maintain system pressures under 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 network companies are expected to deliver.

Own Use Gas

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

P

Price control (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.

Primary outputs

Under RPI-X@20 recommendations, primary outputs concern aspects of the services that network companies provide to consumers (including network users such as generators and shippers). Primary outputs also cover network companies' impact on the environment and compliance with safety obligations.

Profit cap

The maximum payment that the SO is permitted to receive as part of an incentive scheme.

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 before the scheduled next formal review date for the relevant price control.

Revenue driver

A means of linking revenue allowances under a price control to specific measurable events which are considered to influence costs. An example might be to allow a specified additional revenue allowance for each MW of new generation connecting to the network. Revenue drivers are used by Ofgem to increase the accuracy of the revenue allowances.

RIIO–T1

RIIO–T1 will be 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.

RPI-X@20

Ofgem's comprehensive review of how we regulate energy network companies, announced in March 2008. Its conclusions published in October 2010 resulted in the implementation of a new regulatory framework, known as the RIIO model.

S

Safety Case

Is 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

Describe the percentage of profit or loss which the SO will be subject to if the relevant incentive performance measure falls below or exceeds the relevant incentive target.

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.

Smart Meter

A smart meter is an advanced meter which identifies consumption in more detail than a conventional meter. It is capable of two way communication by transmitting meter readings and sending data remotely to suppliers and end users.

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, this would for example include Government and environmental groups.

Storage

Installations owned by Gas Distribution Networks (GDNs) and contracted storage capacity from third parties e.g. 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 event

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 (e.g. loss of supply infrastructure, loss of largest sub-terminal), ii) multiple events (e.g. 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 internal EU energy market. It recognises the need for better co-ordination between European network operators and continuing co-ordination 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 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 8 – 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?

1.6. Please send your comments to:

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