RIIO T1 nationalgrid

System Operator External Incentive Plan

National Grid
Gas Transmission

May 2012

Target audience

Ofgem

About this document

This document sets out our System Operator incentive proposals for the RIIO-T1 period. It describes the operating environment against which the incentives are set and discusses how we will innovate to deliver best value for consumers. We explain how we will manage uncertainty and balance the risk for consumers. Where appropriate, stakeholder feedback on our proposals has been included.

This document is an edited version for all stakeholders of our submission to Ofgem on 31st May 2012 with confidential information removed.

System Operator External Incentive Plan

Table of Contents

Executive Summary

1 National Grid Gas (NGG) undertakes the role of System Operator (SO) for the high pressure gas National Transmission System (NTS) in Great Britain.

2 The regulatory framework within which the SO operates is under review in parallel with the ongoing price control reviews for all UK gas and electricity transmission businesses. This will be the first review of the SO activity under the new RIIO regulatory framework model (Revenue = Incentives + Innovation + Outputs) where a new SO incentive framework will be established for an 8 year duration. The review commenced with Ofgem's consultation on its initial views of the incentive principles to apply from April 2013 in June 2011 followed by the publication of a further consultation on principles and policy on the SO Incentives in January 2012.

3 The proposed framework includes a number of direct financial incentives which will encourage us to minimise the overall costs of operating the NTS. The proposed package also includes incentives around the delivery of transmission capacity in support of new connections to the NTS, to optimise our maintenance activities, to consider environmental impacts and to support the efficient operation of the wholesale gas market.

4 These incentives are designed to encourage us to innovate in the delivery of key outputs valued by customers and to ensure we remain focused on the efficient operation of a safe and reliable gas transmission network and delivering real value to money for consumers. Some of these proposed incentives are financially based while others are reputational. The full set of proposed incentives are set out in the Table below:

Cost Incentives	Financial Incentives	Reputational Incentives
NTS Shrinkage	Residual Balancing	Information Provision (including website data publication)
	Demand Forecasting	
	Greenhouse Gas Emissions (Venting)	Unaccounted for Gas
	Maintenance scheduling &/or Use of maintenance days	Operating Margins promoting competition (market facilitation & reporting obligations)
Constraint Management	Capacity Delivery	Capacity statement on strategy to deliver capacity
		Connection Offer Timeliness & pre capacity application timeline

5 These incentives are distinct from the funding of our internal costs of operating the NTS, which are covered in the System Operator annex of our March 2012 RIIO-T1 Business Plan submission[1].

6 Our high level proposals are summarised in the Table below. The schemes described have been designed to adapt for future uncertainty in the operation of the NTS, as traditional sources of natural gas from the UKCS are replaced with gas imports via interconnectors and LNG shipments, and demand from gas fired power stations becomes more volatile (as the primary back-up to renewable generation). These will create new challenges in operating the NTS against much more dynamic and uncertain supply and demand patterns, making it all the more important that incentives focus the NTS on continuing to deliver the level of service customer and consumers depend upon

High Level overview of proposed System Operator Incentive Schemes

Scheme	Key features
Constraint Management	• Combined Entry & Exit capacity buyback incentive scheme • Ex-ante targets proposed • 3 or 4 year scheme, depending on the release of incremental capacity in March 2013 • 50% sharing factors, +/- £20m annual cap / collar
Delivering Capacity & Connections	• Reputational incentive on the delivery of timely connection offers and progression through pre-capacity allocation activities • Obligation to deliver capacity within 24 months of receiving signal where a pre-construction agreement has been signed • Incentive / penalty to accelerate / defer capacity from obligated lead times • Interim arrangements proposed whilst commercial discussions take place
Shrinkage	• Volume targets to reflect the operating environment for compressor fuel use and CV shrinkage and outturn volume of UAG • Price targets based on forward price for the forecast volume set using average contract price in the 9 months before delivery with volume variance at the month ahead price • 50% sharing factor, +/- £10m cap / collar
Unaccounted For Gas	• Reputational incentive around our activities to identify and address causes of UAG
Residual Balancing	• Price Performance Measure and Linepack Performance Measure retained • Price incentive based on trading at prices within 40% of historic market spread • Linepack incentive based on historic average residual imbalance volume • Increase in maximum daily value to circa £9k, linked to cash-out differential price • +£3.3m / -£3.5m cap / collar

[1] The System Operator annex of our March 2012 RIIO-T1 Business Plan submission can be found on our stakeholder engagement website at http://www.talkingnetworkstx.com/gastransmissionplan/

Demand forecasting	• Existing scheme expanded to incorporate D-2 to D-5 forecasts with seasonal targets • Targets based on 2011/12 outturn forecast accuracy, with adjustment mechanisms to reflect demand volatility going forward • New day-ahead Non Daily Metered (NDM) forecasting incentive • £3.5m collar in aggregate
Operating Margins	• Initially subject to reputational incentive for efficient procurement (cost pass-through) • Potential incentive from year 2 at the earliest once a review into future OM requirements and any consequential changes are complete
Greenhouse Gas Emissions	• Compressor venting volume target based on 2011/12 and 12/13 outturns, with tightening • 1 year scheme initially, enduring scheme to be developed following review of operational venting sources to include within the incentive • 50% sharing factors, no cap / collar, and 10% deadband
Maintenance and Outage Planning	• New incentives developed in response to stakeholder feedback • Publication of indicative maintenance plans (3 years ahead), incentives to reduce NGG changes to the maintenance plan, to accommodate customer changes and to minimise the use of maintenance days • Scheme review after two and four years • +/- £1m cap / collar
Capacity Scaleback	• Off-peak exit capacity product (part of exit reform) to be introduced in October 2012 • Potential financial incentive post implementation of the new exit regime to value the availability of non firm capacity. • Recognises the potential future need for incentivisation in this area; • Currently not valued by the market but potential increased requirements, and hence value, later within the RIIO-T1 period.
Information Provision	• Existing scheme replaced with reputational incentive to report on performance • Engagement to identify opportunities for additional information provision in the future
Customer Satisfaction	• Proposed customer satisfaction incentive on NGG to include the SO role

7 These schemes are designed to operate on an annual basis, with annual targets, caps and collars operating within and 8 year framework.

8 We have engaged with our stakeholders and sought their views on the SO incentive proposals presented herein. Their views have helped to shape this plan, and we have included new incentives in areas that customers have indicated would be of value, in particular around maintenance and demand forecasting.

9 These proposals have been developed to be broadly consistent with the principles set out in Ofgem's recent consultation "System Operator Incentive Schemes from

2013: Principles and Policy" published in January 2012[2], together with the views expressed by ourselves and other stakeholders in response to that consultation. In general, we have sought to create longer-term incentive scheme frameworks, with adjustment mechanisms used to set targets against future uncertainty. Where incentives are new, or where we believe incentives could go 'off-track' over a longer timeframes given the uncertainties we face, we have proposed that incentive methodologies are reviewed periodically to ensure they remain focused on the outputs valued by customers.

10 We have sought to align sharing factors with those set for internal costs under RIIO-T1 where outputs are clearly understood, forecastable & controllable. We have retained the use of caps and collars, to protect consumers and ourselves against windfall gains or losses resulting from factors outside our control. We also propose to retain the concept of Income Adjusting Events to deal with low probability; high impact events outside our control that cannot be foreseen when allowed revenues under the incentive schemes are set. Finally, the incentive schemes will be captured by the range of uncertainty mechanisms first presented in our March 2012 RIIO-T1 Business Plan submission. If and when these are triggered, it may be necessary to reopen related incentive schemes presented in this submission.

11 Over the RIIO-T1 period, the changing use of the NTS may create new opportunities for SO incentives, particularly if new products or services are developed that are valued by our customers. We propose that the incentive framework is sufficiently flexible to accommodate new incentives over the RIIO-T1 period. We have recognised within our submission, for example, the possible need for incentives around the provision of flexibility products or the inclusion of more activities within the maintenance and demand forecasting incentives.

12 These incentives are designed to provide financial reward for the delivery of outputs over and above the baseline level set by the target, and a financial penalty for under performance. However, inherent in these schemes is a range of underlying financial risk that is outside the SO's direct control. The SO does not have a sufficiently large balance sheet to underwrite this risk; therefore this incentive risk is effectively underwritten by the wider NGG balance sheet. Although this risk could be funded via a premium to the allowed return on equity for the NGG TO activity, we propose in this submission that this risk is funded via a £3.3m ex-ante risk premium within the relevant incentive schemes.

13 Overall, the schemes proposed in this Business Plan represent a fair balance of risk and reward and operate in the interests of consumers. Given the uncertainty we face going forward with fundamental changes to the energy markets in the UK and across Europe, it is all the more important that strong incentives remain in place to ensure our interests and those of consumers remain aligned.

14 We look forward to engaging with Ofgem and the wider industry during the Ofgem consultation process.

[2] Ofgem's consultation on System Operator Incentive Schemes from 2013: Principles and Policy is available on the Ofgem website at http://www.ofgem.gov.uk.

Document Structure and Next Steps

15 This document sets out our proposals for our gas SO external incentives and also includes an update to our proposals relating to Constraint Management and Delivering Connections and Capacity, as detailed in our RIIO-T1 business plan in March 2012[3].

16 The first sections of this document discuss the changing SO role over the RIIO-T1 period and the overarching principles applied in developing the SO external incentives before exploring specific proposals for each SO incentive output in detail.

17 The sections for each output provide a brief summary of the current regulatory framework, the expected developments over the RIIO-T1 period including interactions with the TO activity, the risk and uncertainties and our proposed approach.

18 Some sections have further analysis and information provided in appendices to support our proposals. Specifically, the sections on Constraint Management and Delivering Connections Capacity provide an overview of the updated proposals, with further detail provided in two separate Annexes on our proposals in our March RIIO-T1 business plan (Annex A and B).

Our Consultation Process

19 We have engaged with our stakeholders, discussed our proposals and heard their views as to which incentives are of value to them. This has included workshops, meetings, a written consultation and the work previously carried out in relation to the development of our RIIO-T1 business plan. Specifically, we have listened, discussed and acted on stakeholders' views received via our consultation on specific incentives and have reflected them in the development of this plan.

Next steps

20 In June 2011, Ofgem stated its aspiration to lead the development of the SO Incentives for the RIIO-T1 price control review. To inform this process, this document sets out our SO external incentive plan for the 8 years from April 2013.

21 Following our submission of this plan, Ofgem will consider and develop Initial Proposals for this summer and Final Proposals by the end of 2012.

[3] The March 2012 business plan mainly focused on the TO activity, but also outlined our thoughts and proposals regarding the internal costs of the SO.

Supporting Information

22 A summary of many of the current SO incentives, past incentive performance and the link between incentives and charges levied on gas shippers can be found on the SO Incentives pages of our website at: http://www.nationalgrid.com/uk/Gas/soincentives/SupportingInfo/

Contact details

23 If you would like to discuss any issue on our SO Incentives, please contact us via the contact details below:

Louise Wilks	Juliana Urdal
SO Incentive Development Manager	Senior Regulatory Analyst – Gas
01926 653872	01926 656195
louise.wilks@nationalgrid.com	juliana.urdal@nationalgrid.com

24 To register your interest in receiving future communications on SO incentives please email: SOIncentives@nationalgrid.com.

25 The dedicated web pages for this incentive review process are available at the following address: http://www.nationalgrid.com/uk/Gas/SOIncentives/

The System Operator Role: Now and into the future

The role of the SO today

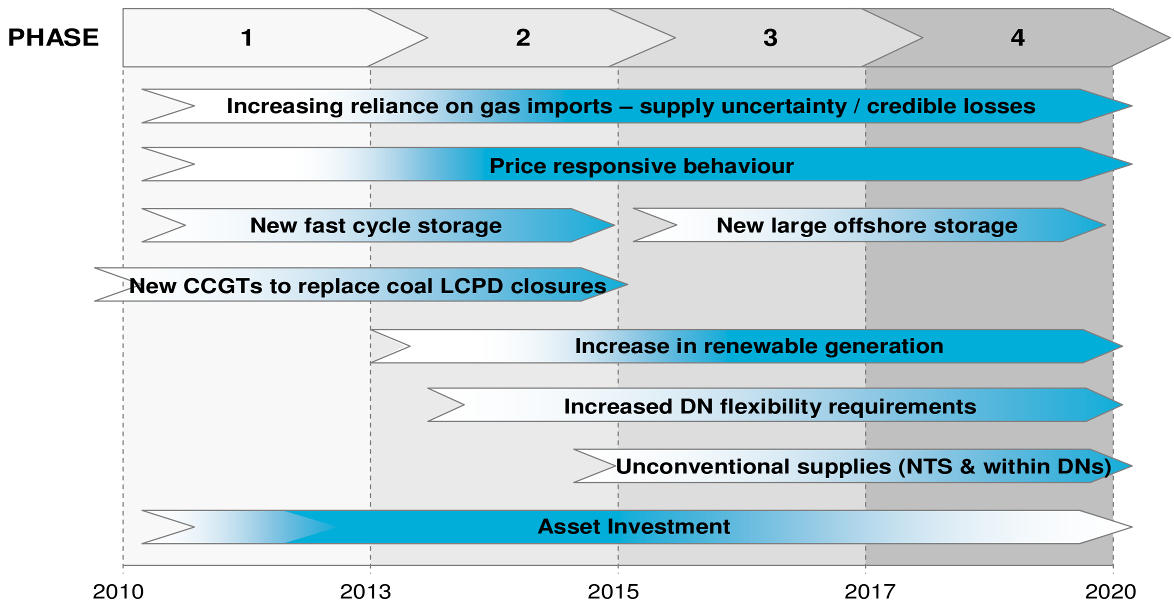
26 Our principle role as the System Operator is to operate the NTS to ensure that gas is transported safely, reliably and efficiently across our network. In line with our obligations, we balance the national supply and demand for gas and facilitate the operation of the market.

27 As SO, our challenge is to ensure that throughout the RIIO-T1 period we have the appropriate level of operational capability in place to ensure safety and security of supply, but also to deliver the level of service customers require.

The challenges faced

28 Over the next decade, we will need to build on our existing capabilities in order to continue to deliver the outputs valued by our stakeholders whilst meeting our key obligations. Increasing supply and demand volatility will present an increasing challenge for the SO. The need to maintain the safe and reliable operation of the system whilst meeting changing customer needs will be performed against a backdrop of changing operating environments, regulatory change and enabling optimal access to the network.

29 Underpinned by different drivers across the decade, change is likely to be incremental and is illustrated, and discussed in more detail, below.



30 In parallel, the SO will also be managing the impact of work to facilitate changes in the network[4] due to:

(a) Replacement of compressors to align with legislative requirements of the Industrial Emissions Directive (IED);

(b) Work to maintain the integrity and capability of ageing network infrastructure; and

(c) Incremental capacity and flexibility requirements of customers.

31 All will reduce the level of capability offered across the NTS going forward.

32 Similarly, conditions on the day may not facilitate the scheduled network access to be undertaken or may result in the need to take commercial actions to allow such access to be taken.

Operating in a changing supply and demand environment

33 Supply and demand in the UK gas market is becoming increasingly volatile, and we expect this trend to continue looking forward. Declining supplies from the UKCS and increased diversity of supplies at entry means that gas shipments can be supplied from any terminal in varying volumes from one day to the next. Similarly, new storage capacity, increasing wind volumes driving more intermittent CCGT operation, and changes to Distribution Network (DN) requirements for flexibility from the NTS all have the ability to significantly impact on how our customers wish to use our network.

34 Increasingly, user behaviour is being driven by commercial considerations and the opportunity to take advantage of price differentials within day and between UK and European markets. Interconnector, LNG and fast cycle storage facilities have the capability to vary their volumes quickly allowing shippers to balance their position later in the day to meet End of Day (EOD) balance. In addition, the closure of coal plant means that CCGT output will become more intermittent as renewable generation grows over the period. This intermittent behaviour will challenge the operation of the NTS.

35 Such variability will challenge our ability to forecast and set up the network optimally, with increased uncertainty regarding system imbalance leading to a need for more adaptive operating strategies. Accommodating demand variability will challenge how we manage locational pressures and alter compressor usage to ensure gas is transported to the required locations. Similarly, we will need to evolve our planning processes to facilitate the level of outages and maintenance required.

36 In essence, more uncertain supply and demand patterns, flow rates and hence flow directions around the network are less predictable. In setting our operational strategy, a wider range of scenarios will need to be considered for the day to cover the risk of the potential scenarios of how the day may unfold.

[4] More information is available in the Incremental Entry and Exit Capacity and Industrial Emissions Directive (IED) sections of the Managing risk and uncertainty annex of our March 2012 RIIO-T1 Business Plan on our stakeholder engagement website at www.talkingnetworkstx.com/gastransmissionplan

Facilitating markets and supporting regulatory change

37 Substantial regulatory change is expected to be triggered by EU regulatory requirements such as the new European network codes and guidelines, and other regulations[5]. At this stage, it is unclear exactly what impact changes will have on the Uniform Network Code (UNC) and the GB regime but it is likely to involve significant changes to GB codes and amendments to our licence. This in turn will most likely require changes to business processes, information provision requirements, IT systems and even network assets and therefore could impact on incentive performance and drive changes to align the incentive framework.

38 Significant changes to the GB regulatory framework are also evident on the horizon, and may include UNC modifications to deal with Electricity Market Reform, the Significant Code Review on UK security of supply, and the need for network flexibility amongst other things.

39 All have the ability to impact on the SO role into the future, potentially leading to changes to the products and services we provide to our stakeholders, and the way in which we operate the network. Consequently, changes to the incentive framework may also be required in order to continue delivering best value to consumers.

Adapting to the operating environment

40 The changing operating environment means that we are continually developing strategies, tools and capabilities to ensure the continued safe and reliable transportation of gas while meeting the needs of our stakeholders. Over the RIIO–T1 period, we will enhance our capability through;

(a) The establishment of tools to support decision making in line with the delivery of exit reform;

(b) Additional functionality, tools and processes in order to manage an increasingly variable operating environment, including capability enhancements in operational forecasting, real-time scenario analysis, control strategy optimisation and network status assessment[6]**;**

(c) The introduction of real time network optimisation tools; and

(d) New and revised industry tools and processes to allow effective management of within day (sub daily balancing period) dynamic supply and demand.

41 The optimum solution may well require a combination of these options, depending on specific operational requirements and cost/benefit in each case. These potential changes could also impact on SO activities, both directly (e.g. impact on system access and compressor fuel use) and also when the optimal solutions are based on Rules and Tools.

---

[5] This is discussed in further detail in the System Operator section of our detailed plan of our March 2012 RIIO-T1 Business Plan on the National Grid website at http://www.talkingnetworkstx.com/gastransmissionplan/

[6] This is discussed in further detail in the System Operation annex of our March 2012 RIIO-T1 Business Plan on the National Grid website at http://www.nationalgrid.com/NR/rdonlyres/87A406CE-136F-4F7C-936F-ADBF0D8F86C3/52255/2012_NGG_detailed_plan_redactedsecure.pdf.

42 These capabilities focus on the processes, resources and tools we can develop and implement as SO, however development of operational capabilities is only one of a range of options to resolve challenges for the future. We are also therefore considering enhancements to the commercial regime in which we operate, how we can further optimise the use of existing network assets, and how best to target investment to meet future stakeholder needs.

43 Against this background of change we will continue to work closely with our stakeholders and customers. We will use this close collaboration to develop policies and services which bring value to them as we seek to develop the network to ensure it continues to deliver safe, reliable and affordable energy.

In summary

44 The environment in which we operate will change substantially over the next ten years, impacting the development and the operation of the NTS. SO incentives will continue to have an important role to play in protecting consumers by ensuring that the outputs valued by customers are delivered against this uncertain future. Any framework will need to be able to evolve to enable the development of new incentives given the likely changes in the operating environment.

SO Incentive Principles

Overview

45 This section describes the principles against which we have developed our proposals for a package of SO incentive schemes to operate over the 8 year RIIO-T1 price control period. They draw on the principles set out in Ofgem's recent consultation "System Operator Incentive Schemes from 2013: Principles and Policy" published in January 2012[7], together with the views expressed by ourselves and other stakeholders in response to that consultation.

46 SO incentives deliver significant benefits to stakeholders and align industry needs to our financial performance. These incentives create a focus on outputs valued by stakeholders, creating an environment whereby the System Operator develops innovative solutions, working closely with the NTS Transmission Owner (TO) activity, to deliver ongoing improvements in the gas transportation services they provide to customers and consumers.

47 In particular, our view is that incentive strength should reflect the operating environment that we work within, focusing on areas where we have more control and it is beneficial to give us more discretion. These incentives need to adapt and evolve to ensure that they remain appropriate for industry's needs and the challenges in the period to 2021. The incentives should deliver a fair balance between risk and reward for industry, consumers and NGG.

Background

48 SO incentives have been in place in various forms for over ten years and have delivered significant benefits to stakeholders and consumers over this period. These incentives have created a focus around the outputs that are valued by stakeholders, creating an environment in which NGG has developed innovative solutions to deliver ongoing improvements to the gas transportation services we provide.

49 The principles of SO incentives are aligned to the RIIO philosophy (Revenue = Incentives + Innovation + Outputs) and we are committed to ensuring that the SO incentive arrangements integrate with the overall regulatory framework in which we operate. In particular, the framework should promote fully integrated and co-ordinated decision making between our SO and TO activities, ensuring efficiency and long-term value for money for stakeholders.

50 Going forward, the NTS will need to deal with more diverse supply and volatile demand. The supply side will see greater emphasis on LNG imports, European imports via Interconnectors and injections to the network from new storage facilities, all of which are likely to be more flexible/less predictable than traditional supplies from the North Sea. The demand-side will see greater volatility in CCGT demand due to increased intermittency in electricity generation, greater volatility in interconnector

[7] Ofgem's consultation on System Operator Incentive Schemes from 2013: Principles and Policy is available here: http://www.ofgem.gov.uk/Pages/MoreInformation.aspx?docid=277&refer=MARKETS/WHLMKTS/EFFSYSTEMOPS/SYSTOPINCENT

exports with increased cross-border trading between EU Member States, and consumers becoming more responsive to gas price signals from Smart Meters.

51 Against this changing future and uncertain future, we believe that it is more important than ever that strong incentives remain in place to ensure that the SO continues to deliver value to customers during this very uncertain and volatile period.

Over-arching Principles

52 The package of SO incentive schemes set out in these proposals have been designed against the following over-arching principles:

Delivering customer value

(a) The incentives should align our commercial interests with the interests of consumers

(b) Incentives should reflect our ability to **deliver improvements** to key outputs that are valued by customers

Duration of Incentive Schemes

(a) We have developed an 8 year incentive framework which promotes **alignment and co-operation between SO and TO** activities to deliver the most optimal outcome for stakeholders in the longer-term;

(b) The duration for which scheme parameters are proposed within this framework depend on the confidence we and stakeholders have that required outputs can be delivered at acceptable cost, given the **predictability of costs and outputs** or **confidence in data and modelling.** Shorter-term schemes are proposed for **new arrangements** to ensure they remain fit for purpose as they develop;

(c) Given forecasting uncertainties and the need for transparency, it is proposed that each incentive should **operate and report annually against associated targets.** Methodologies/mechanisms are proposed for setting **annual targets** over the duration of the incentive schemes to deal with forecasting uncertainty;

Managing Uncertainty and Change

(a) We propose to **limit windfall gains or losses** through the use of target **adjustment mechanisms** to mitigate against market factors outside our control, with such mechanisms being **reviewed periodically** within the RIIO-T1 period;

(b) Re-openers to deal with significant **game changers**, for example, Significant Code Reviews such as the current review of Gas Security of Supply, and European Union driven reforms are proposed. We also propose to retain **Income Adjusting Events** to ensure appropriate funding can be provided for significant changes to costs which were not envisaged when allowed revenues under the incentive schemes were set and are not covered by any of our proposed uncertainty mechanisms.

SO Exposure to Risk

(a) To the extent that we bear risks on behalf of consumers that we cannot fully control, we have proposed a risk premium within the package of incentives to finance the management of this risk;

(b) We have sought to ensure we are able to earn a fair return in order to maintain the financial viability of the SO and provide adequate funding for the development of new capabilities; and

(c) We have sought to ensure we are not exposed to unreasonable risk in circumstances that we are unable to control or reasonably forecast.

Incentivising Key Outputs

53 Incentivising key outputs of regulated network utilities is at the core of the new RIIO-T1 regulatory framework. Our proposals identify a range of incentives to promote a high level of performance in the economic, efficient and co-ordinated delivery of a key set of SO outputs in a manner that is valued by customers. Such incentives will provide us with the opportunity to demonstrate that we operate the NTS efficiently, adding value in our role as the SO.

54 Incentives ensure we align our actions with the interests of customers where we have some degree of influence or control over a given output, and can add value in improving the delivery of that output. Furthermore, incentives are appropriate where they can deliver benefits valued by customers over and above those required through established statutory, licence or contractual obligations.

55 However, where incentives would expose the SO to factors it has little or no influence over, there is a risk of unwanted consequences including unjustified windfall gains or losses. Generally, the more control the SO has over a particular output, the greater the scope for incentivisation, and conversely, the scope for incentives around outputs over which the SO has limited influence is small. We have sought to identify and avoid incentives that might encourage behaviours that would work against the best interests of customer and consumers.

56 Incentives on SO outputs can be either financial or reputational. Key outputs are generally subject to minimum statutory, licence or code obligations; they are subject to reporting requirements and often subject to infringement penalties if they are not delivered. The packages of financial incentives set out in these proposals reinforce and sharpen these obligations to encourage the delivery of outputs beyond minimum requirements.

57 Key gas SO outputs valued by stakeholders include:

(a) the provision of incremental entry and exit capacity

(b) optimising capacity management and maintenance planning to deliver system access for stakeholders whilst enabling the delivery of TO outputs

(c) appropriate residual balancing behaviours

(d) minimising shrinkage costs; including the identification of UAG;

(e) providing accurate and timely information to support efficient market operation such as demand forecasts; and

(f) Facilitating timely connections to the NTS and minimising our impact on the environment.

Duration of Incentive Schemes

58 The proposals set out in our submission are based on an 8 year incentive framework from April 2013 that aligns with the duration of the RIIO-T1 proposals. We support the move towards longer-term schemes. This creates stronger incentives to develop solutions and drive efficiencies that are in the long-term best interest of customers and consumers.

59 However, the energy industry is entering a period of significant uncertainty and change as we move towards a low carbon economy during the next regulatory period. "Now and into the future" section of this submission. These external drivers will impact on the ability to forecast external SO costs and outputs with any degree of certainty over the next 8 years. Setting long-term ex ante targets against this uncertainty is not a robust basis for setting a long-term incentive scheme.

60 Stakeholders have mixed views on the duration of the incentive schemes. The majority welcome the alignment of the SO incentives with the RIIO regulatory framework but there are mixed views on whether the incentives themselves should be set over an eight year period.

We support the introduction of a longer regulatory period for setting the SO incentives framework. We believe that this will encourage the SOs to take longer term views and decisions in their role as SO which should result in lower costs to consumers.
EDF's response to Ofgem's consultation on "System Operator incentive schemes from 2013"

We have overriding concerns about setting the underlying methodology for SO incentives for potentially an 8 year period, particularly in light of the changing pattern of usage of the National Transmission System (NTS) and the future European Code changes, both of which have the potential to significantly alter the wholesale trading arrangements in the GB.
EON's response to Ofgem's consultation on "System Operator incentive schemes from 2013"

61 Longer term schemes should be implemented in such a way as to ensure the incentives remain focused against an uncertain future and avoid windfall gains/losses. Variable scheme durations are therefore proposed within the 8 year framework where there are, for example, issues regarding the predictability of costs and outputs or confidence in data, methodologies and mechanisms used to set targets. Shorter-term schemes are proposed for new incentives to ensure they remain fit for purpose as they develop.

Annual incentives within an 8 year framework

62 We propose that each incentive scheme operates annually within this 8 year framework. Our customers have stated that stability in their charges is important and we support the principle that charges should be cost-reflective, timely and appropriately targeted.

63 Consequently, performance should be judged against an annual target, and aside from any residual reconciliation, incentive payments or penalties would form part of the transportation and neutrality charges levied for that year to avoid large adjustments at a later date[8]. Furthermore, any applicable caps and collars, target adjustment mechanisms or Income Adjusting Events would operate discretely on an annual basis.

64 A number of stakeholders welcomed the principle that each incentive scheme will be set independently of the others, although there were concerns that this type of approach may increase the administrative burden and reduce overall transparency. We have been cognisant of these concerns in the development of our proposals.

We welcome Ofgem's recognition that the incentives scheme length will need to be considered carefully for each output and cost incentive scheme taking account of modelling data certainty, predictability of cost and risk.
Association of Electricity Producers response to Ofgem's consultation on "System Operator incentive schemes from 2013"[9]

Target Setting and Adjustment Mechanisms

65 Financial incentives should only apply to outputs where an appropriate target can be set (i.e. they can be forecast), and performance against that target can be measured in a transparent, auditable manner. The setting of targets for an 8 year period will be particularly challenging for the NTS.

66 Targets based on forecasts (ex-ante targets) set against an uncertain future could easily lead to windfall gains or losses, and therefore a loss of focus in the incentive properties of the scheme. Incentives that could lead to windfall profits or losses may not drive the desired behaviour. This could reduce the appetite to invest in an area to improve if potential windfalls overshadow any improvement that the investment is designed to deliver, as the profit (or reduced loss) from that investment may not be realised. This may lead to sub-optimal performance and therefore reduced value for customers.

67 In order to reduce the scope for windfall gains or losses, adjustment mechanisms can be used in the setting of targets on an annual basis. An adjustment mechanism or methodology can be developed to calculate an annual target based on a defined set of inputs. Where external factors cannot be forecast and/or the SO has limited or no control over them, these factors can be treated as ex-post outturn inputs. This approach sharpens the incentive properties of the scheme by allowing greater focus on those factors we can influence or control (by eliminating those factors we cannot). This should assist with maintaining the incentive focus of the scheme, and reduce the scope for windfall gains or losses.

68 Ideally, these adjustment mechanisms should be transparent in the way they operate and relatively simple to understand. Furthermore, it is important to develop a robust

[8] See National Grid Gas (NTS) System Operator Incentives – Supporting Information Version 4.0, for a summary of the impact of incentive payments on the SO commodity charge -www.nationalgrid.com/uk/gas/soincentives/supportinginfo/

[9] Energy UK was established in April 2012 following a merger of the Association of Electricity Producers, the Energy Retail Association and the UK Business Council for Sustainable Energy.

adjustment mechanism or methodology at the outset, so far as this is possible, to minimise the requirement to re-open these adjustment mechanisms on an ad-hoc basis. This approach is supported by stakeholders.

69 However, any adjustment mechanism or methodology that seeks to simulate the complex operating environment and networks we operate over an uncertain 8 year time horizon is likely to feature some degree of complexity and will never be 100% accurate. In theory, the more complex the mechanism, the more accurate it will be, but complex mechanisms can become 'black boxes' requiring a significant overhead to manage. Our aim is to find the right balance between the complexity of such mechanisms, their accuracy, and ensuring they are understandable.

70 Using this approach to setting targets within a long-term framework is particularly important given fundamental changes in the operation of the NTS over the next 8 years given the changing supply and demand environment, evolving market frameworks and more challenging system access requirements.

Periodic review of target setting mechanisms

71 The operation of the NTS is a highly complex activity, and any mechanism or methodology trying to replicate outputs from this activity against an uncertain future are going to involve degrees of inaccuracy. Where there are concerns over the target setting adjustment mechanisms or methodologies used to capture long-term uncertainty, these can be reviewed periodically (e.g. review points are proposed for the new maintenance incentive to enable a review of the behaviours driven) within the 8 year incentive framework. This view is supported by stakeholders.

“” *Given the uncertainty of the period to 2020 and the requirement for the regulatory framework to be adapted in light of these uncertainties it may be challenging to set meaningful schemes that deliver continual improvement in SO performance for durations in excess of 12 or 24 months.*
RWE Npower's response to Ofgem's consultation on "System Operator incentive schemes from 2013"

72 Such reviews are particularly relevant during the early application of a given mechanism where confidence in data and modelling is evolving or the predictability of costs and outputs is particularly uncertain. Stakeholders support regular reviews of the incentives to make sure they remain relevant to the developing environment.

Sharing Factors

73 Sharing factors are proposed for incentive schemes which are focused on minimising costs. Exposing the SO to a share of the external costs it manages creates an incentive to manage those costs efficiently. Sharing factors can range from 100% where the SO bears all the risk of managing those costs and the Shipper is charged a fixed price, to 0%, where the SO has an obligation to manage costs efficiently but has no direct financial incentive to do so, so Shippers bear all the cost variation.

74 External SO costs are far more volatile than internal SO costs and sharing factors have traditionally been relatively low to reflect the degree of control we have over these external costs.

75 In creating alignment with TO incentives under RIIO, we support the concept of consistent sharing factors to facilitate economic decisions where there are significant trade-offs between SO and TO costs and outputs. This is contingent on ensuring the

incentive schemes are focused on elements we can control by minimising the impact of those we cannot.

76 Inevitably, sharing factors of up to 50% to align with the TO proposals will introduce significant additional risk onto the SO activity[10]. Nevertheless, the package of proposals (comprising target adjustment mechanisms, caps/collars, durations, income adjusting events and risk financing) set out in this submission are designed to enable this alignment to occur.

The Use of Cap and Collars

77 While we are proposing that targets are set using adjustment mechanisms to take account of factors we cannot forecast accurately or control, there will inevitably be continued uncertainty around the accuracy of theses mechanisms used to capture the complex reality of the networks we operate and the increasingly uncertain environment we operate within.

78 Targets could go significantly ‘off track’ over the duration of the scheme as a result of events outside our control. In order to protect customers and the SO from windfall gains or losses resulting from such events, we believe that caps and collars should continue to apply, but should be set at a level so as not to discourage economic trade-off in decisions between our SO and TO activities.

79 In responses to Ofgem’s consultation on “System Operator incentive schemes from 2013” a number of stakeholders said caps and collars could undermine the SO taking long term decisions and could undermine the alignment between the SO and TO activities. However, stakeholders are in favour of caps and collars as they protect them from any windfall gains or losses.

“” *We acknowledge that by limiting the gains or losses that the SO can achieve over the incentive scheme period, Ofgem also limits the incentive that the SO has to manage those risks… However, we are very concerned that Ofgem appears to have failed to recognise that the use of caps and floors also protect market participants and consumers from the SO achieving excessive gains and large swings in the incentive costs which are ultimately borne by consumers.*
SSE’s response to Ofgem’s consultation on “System Operator incentive schemes from 2013”

80 As we gain greater confidence in the mechanisms used in setting annual targets, these caps or collars could be widened over time, possibly at the point that the target setting adjustment mechanisms or methodologies are reviewed and refined.

Framework Flexibility

81 As part of our package of proposals, it is appropriate to include provisions to allow individual schemes to be revisited in the event of significant changes to the commercial and regulatory framework in which we operate. Potential changes could be driven by drivers such as GB & EU energy policy reforms as explained further in the ‘GB & EU market facilitation’ section of our ‘Managing Risk and Uncertainty’

[10] Operational expenditure is currently subject to a range of incentive rates from 20% to 100% for the NTS depending on the level of control for that type of expenditure.

annex to the March RIIO-T1 business plan submission. Stakeholders wish to see the incentive remain relevant so agree that they should be revisited in the event of significant changes.

“”

We agree that price, political/regulatory and operating environment are sources of risk that are beyond the control of the SO and so should be mitigated against …
EDF's response to Ofgem's consultation on "System Operator incentive schemes from 2013"

82 Changes to the way the NTS and the wholesale gas market operate in the future may create opportunities to develop new incentive schemes. These might be on the back of new services or products that are developed by the SO to meet future industry needs. The framework should be sufficiently flexible to allow new incentives to be created during the 8 year RIIO-T1 period where a clear customer benefit can be demonstrated.

Income Adjusting Events

83 Income Adjusting Events (IAE) provide a further uncertainty mechanism to deal with significant and unexpected events or circumstances outside our control, where funding for these events or circumstances was not included in setting the allowed revenues under the incentive schemes or our proposed uncertainty mechanisms.

84 Additionally, IAEs offer the opportunity for Shippers to make representations to Ofgem where they believe additional costs have been incurred or costs have been saved.

85 They provide a useful mechanism within the licence to deal with changes over the RIIO-T1 period which could not have been anticipated at the time of the RIIO-T1 settlement being agreed. Hence they build in future proofing within the licence for unforeseeable events.

86 At present, an income adjusting event in relation to external SO costs can be any of the following which has an impact on SO costs of over £2m (internal SO costs have a threshold of £1m):

(a) an event or circumstance constituting force majeure under the UNC;

(b) where NGG serves a termination notice on a shipper resulting in a loss in revenue from capacity sales to that shipper;

(c) an event or circumstance resulting in the declaration of a network gas supply emergency; and

(d) an event or circumstance which Ofgem approves as an income adjusting event.

87 The current drafting within the licence includes details of the circumstances under which an IAE can be applied for, together with the consultation process and governance procedures which need to be followed before a determination can be made. We suggest that this form of drafting is retained within the licence to ensure that the provisions are only invoked when the particular case being considered to be treated as an IAE would stand up to such consultation and scrutiny.

88 During the TPCR4 period, we have only made one application for expenditure to be treated as an IAE. We applied to the Authority for costs to be considered for the

purposes of the IAE mechanism which related to the development of IS systems to implement a number of significant commercial framework changes to the gas entry capacity regime (including trade & transfer). The costs exceeded the £1m threshold (as they were internal SO costs) and the proposed income adjustment as a consequence of these additional costs was £463k. The Authority did not veto this notice and therefore the IAE provision was invoked.

89 As noted above, the provisions provide for Shippers to also raise IAEs if they consider that events or circumstances have occurred that result in costs being greater or less than expected at the time the incentive scheme revenue was set. For example, an Income Adjusting Event was raised in 2011 by a Shipper in relation to the Canatxx Shipping Limited signal for entry capacity at Fleetwood. In this case, the Authority did not agree with the notice made and therefore the IAE provision was not invoked in this instance.

90 The two-way nature of the IAE provisions therefore represents an important safeguard to the industry when they believe costs have changed by a material event. This is a principle which we believe should be retained and for which there is clear stakeholder support.

In general we recommend that Ofgem should be strongly averse to reopening price controls or incentive schemes as the use of such retrospective regulation can undermine investor confidence in the market. However, given the length of the proposed incentive scheme period, we believe it would be appropriate to introduce a General Uncertainty Mechanism … on the understanding that it is only used to mitigate events which are unforeseen, have a low probability of occurring and have a significant impact on the SO.

SSE response to Ofgem's consultation on "System Operator incentive schemes from 2013"

91 These provisions have been a fundamental part of the incentive framework for many years. They are rarely used, and therefore represent a low overhead to maintain, but represent an important mechanism to ensure that obligations with regard to SO activities can be funded in light of significant unexpected events or circumstances not envisaged when revenue allowances were set and overall cost to consumers can thus be minimised.

92 Given the intention to move towards longer-term schemes, in which the range of uncertainty becomes much broader due to the length of the schemes and the fundamental changes we expect to see across the UK energy sector over this period, we believe it imperative that this form of uncertainty mechanism is retained. This will help to ensure that the SO continues to be subject to a fair, credible and transparent incentive framework.

93 As part of our package of proposals for SO incentives under RIIO-T1, we therefore propose the continued application of Income Adjusting Events (IAEs) at the current threshold of £1m for internal SO costs and £2 for external SO costs.

Financing Risk

94 The potential introduction of incentive schemes for up to 8 years with higher sharing factors and wider caps/collars will significantly increase the level of risk faced by the SO.

95 The SO activity does not have a sufficiently large balance sheet to underwrite the risks associated with these incentives. These risks would effectively be underwritten by the wider NGG balance sheet, and need to be funded accordingly.

96 We also note the statement in Ofgem's January consultation:

> "*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*."

97 The funding risk associated with underwriting the SO activity could be factored into the allowed return on equity for NGG's wider TO activity. However, we propose that this risk is funded via a risk premium within the incentive package for our SO activity, reflecting the risk that the NGG balance sheet will need to underwrite. Our proposals in this regard are detailed in the Risk and Uncertainty section.

SO Innovation

98 The changing nature of gas flows on the NTS, new entry points, and the impact of increasing wind intermittency on the electricity network, and an increasing requirement for a flexible NTS means that innovation will be at the heart of our business going forward. The SO will inevitably need to adapt the way in which it operates in order to deliver against the challenges that it faces.

99 To deliver the outputs that our stakeholders require and to facilitate meeting the UK Government's carbon targets, we will need to:

(a) Adapt and innovate to ensure that our processes knowledge and asset capabilities continue to develop to align with our stakeholders' needs;

(b) Take a leading role in developing initiatives to minimise the UK's carbon footprint;

(c) Influence and drive changes in European and UK legislation; and

(d) Continue to find innovative ways of recruiting, training and retaining our staff and knowledge.

100 It is vital therefore that the industry as a whole embraces the innovation challenge. We will need to adapt over the RIIO-T1 period in order to deliver valued outputs including the delivery of efficient investment.

101 Stakeholders have told us throughout the RIIO-T1 engagement that innovation is crucial in enabling us to meet future challenges and to continue to deliver our services in a safe, reliable and efficient manner. When it comes to innovation funding for the SO some stakeholders said funding should not be restricted solely to TO activities whereas another said they would wish to see what we were planning to do with the funding before they could support the proposal.

102 We propose to extend the Network Innovation Allowance (NIA) as proposed under RIIO-T1 to the SO, thereby allowing access to vital innovation funding information on what we are planning to do with the funding is included below.

What have we done so far?

103 During the TPCR4 period, we have maximised our participation in innovation projects as a TO and an SO, focusing on the technical development of networks to deliver tangible benefits to the end consumer in terms of financial, quality of supply, environmental or safety measures. The existing Innovation Funding Incentive (IFI) scheme has proven to be a pivotal tool in helping address the challenges that we, and the wider industry face.

104 Many of the operational enhancements that we have made through innovative ideas are incremental in nature, and have helped to minimise cost increases or the delivery of network outputs, including areas such as;

(a) Improved prioritisation of pipelines for in-line inspection allowing for the minimisation of plant outages, system access requirements and customer disturbance

(b) Variable speed drive compressors to reduce our electricity usage at individual sites, and subsequent operational costs and carbon footprint;

(c) Above ground meter enhancements which have helped provide more accurate flow meter data and customer billing

(d) Two stage recompression to reduce the volume of gas released to atmosphere when decommissioning a pipeline; and

(e) Understanding and developing alternatives to venting natural gas on the NTS

105 Whilst traditional technological based innovation has a major part to play in delivery, our plan recognises that innovative changes to commercial regimes, operations and processes have an equal part to play in delivering the right solutions. Commercial innovation can take many forms such as contract options, regulatory options or delivery mechanisms such as:

(a) Contractual arrangements for multi day trades to balance the system

(b) Changes to credit arrangements to underwrite investment and protect the wider industry from default risk

(c) Developing code frameworks to enable new gas sources to connect efficiently; and

(d) Reviewing and developing Operating Margins provision to enable wider market participation such as from power stations and supply points

What we will be doing in the future

106 Going into the RIIO-T1 period, continued collaboration will allow a holistic approach to innovation. This will lead to maximum value as we learn from best practice and harness specialist skills. We will be working alongside our TO business to gain the benefits and adapt the lessons and fundamentals of the three pillar innovation strategy[11] as set out in our RIIO-T1 TO plan.

107 The strategy relies on three pillars to deliver successful innovation solutions into our business:

(a) **Identification and prioritisation of research areas**: We will continue to listen to our stakeholders and focus our efforts on delivering innovative solutions to address their needs. We will utilise the strength of our own staff to generate ideas. We will continue to scan the technology landscape and work with key suppliers to identify opportunities.

(b) **Harnessing innovative capabilities**: We will continue to build a more innovative culture within our company to make sure that we can deliver our company vision of being an innovative leader in energy management. We will give our staff the tools and time to investigate different innovative solutions and foster an environment where this is the norm rather than the exception.

[11] The 3 pillar approach is set out in the March RIIO-T1 innovation Strategy document which can be found on our stakeholder engagement website: www.talkingnetworkstx.com/gastransmissionplan

(c) **Collaboration with external parties**: We recognise that we cannot fully optimise the use of innovation funding using our own resources. We will continue to build strong links with research institutes, academia, suppliers, manufactures, Transmission Owners, DNs and other institutions within the energy value chain to harness their capabilities.

108 Innovation in all its forms will be a key element in driving our business forward, enhancing our ability to maximise the required outputs for the benefit of consumers and stakeholders alike. The continued development of an innovation culture within our business will create efficient, effective and strategic solutions which are central to solving the challenges that face the wider energy industry and consumers alike.

Funding the SO for innovation

109 We welcome an innovation fund as stated in our RIIO-T1 TO plan of the maximum 1% of revenue under the Network Innovation Allowance (NIA)[12]. Any such fund should be established such that both TO and SO are able to access innovation funding, both separately and in partnership, hence allowing for optimisation of processes across the TO and SO.

110 The NIA funding profile is based on the current projected revenues for the RIIO-T1 period as set out below and would represent an increase in our innovation funding to date. The table below details the level of NIA funding that has been requested as part of the submission for the RIIO-T1 period. It is proposed that NIA funding is tied to annual revenues rather than the average of the eight year period. This proposal has been made on the basis that we receive the full 1% allowance.

2013/14	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	Total over RIIO-T1 period
£7.4m	£7.4m	£7.7m	£8.4m	£10m	£10.4m	£9.6m	£9.2m	£70.1m

111 Inevitably with innovation, some benefits will be realised years into the future, and any innovation funding should also facilitate innovation initiatives into the longer term where benefits are achievable.

112 The Network Innovation Competition (NIC) process will also offer a vehicle for delivery of innovative solutions. We expect to propose a number of joint TO / SO / Distribution Network (DN) projects that deliver significant value in cutting costs to consumers and helping to meet carbon reduction targets.

113 Innovation is supported by our stakeholders with many seeing it as absolutely critical in enabling us, and the wider energy sector, to operate a sustainable, reliable network affordably.

[12] RIIO-T1 Innovation Strategy, March 2012 http://www.nationalgrid.com/NR/rdonlyres/FA3DDA80-660A-4D08-A976-A8C8FA297308/52221/2012_NGG_Innovation_strategy_v1Fullyredacted.pdf

114 Without innovation, transitioning to a low carbon economy and achievement of the UK Government's carbon reduction targets becomes much more difficult and potentially more costly. The sooner that innovative solutions to the challenges can be realised, the greater the benefit to industry, the environment and the end consumer.

SO/TO Interaction including links to the RIIO-T1 plan

115 The incentive schemes proposed within this document have been developed to create a foundation to deliver long term value to consumers. The success of these schemes will however, be heavily influenced by the interaction between the NTS TO and the SO.

116 The role of the TO and SO are intrinsically linked, which means the performance of the SO for example, can be highly dependent upon decisions that have been made by the TO in terms of the way it designs, constructs and maintains its assets. The TO and SO interaction is however, simplified given the common ownership of the TO and SO together.

117 Our unique position as TO and SO provides us with the opportunity to make holistic decisions between the two distinct areas and allows us to optimise our approach. Through undertaking both roles we are incentivised to make decisions which balance the costs and risks of both forms of control. As such we consider the impact of decisions across our business and also look for opportunities to minimise costs through this joint role.

118 There are two main interactions in this area we consider:

(a) Cost and risk balance between TO capital investments and SO costs and actions; and

(b) TO capital investments versus development of the commercial framework.

119 For example, when considering a customer's request for incremental capacity we will consider all commercial options (rules), operational arrangements (tools) and physical investments (assets) available in order to determine the most efficient outcome for consumers. This may include putting in place a contract with a particular operator on the network. We will keep these trade-offs under review throughout the business plan period and change the trade-off if it no longer offers the most efficient option, i.e. if liquidity in the market reduces and costs for contractual solutions become disproportionate relative to physical build.

120 As an alternative, the TO could potentially invest in the NTS to provide direct benefit to the SO. Examples of where this could happen include:

(a) Through additional TO investment, assets could be upgraded or modified to reduce leakage of natural gas; and

(b) TO investment to modify a compressor unit could benefit the SO through reduced emissions and compressor fuel usage.

121 We have taken on board the stakeholder feedback regarding interactions between the TO and SO. Such feedback has influenced our proposals on Operating Margins (OM), capacity in respect of commercial versus build solutions, and questioned the economics of investing to minimise venting over and above legislative requirements.

122 Key features within our TO plan that will potentially interact with the SO incentives described within this document include:

(a) Provision of incremental capacity

(b) Network flexibility and Changing Operational Environment;

(c) Asset health; and

(d) Investment to comply with environmental legislation

Provision of Incremental Capacity

123 Load related investment can be required to extend or reinforce the NTS, driven by customer requests for new connections or increased entry or exit capacity. In most cases, load related investment is underpinned by a signal for incremental capacity above the prevailing obligated level[13] and an associated revenue driver having been agreed with Ofgem where necessary. Investment is progressed following a firm signal for capacity received as part of the prescribed entry and exit capacity processes, although planning can begin at a high level prior to market signal.

124 The provision of incremental capacity has the potential to impact upon the gas incentive schemes detailed within this document, particularly Constraint Management, Shrinkage, Greenhouse Gas Emissions, Maintenance and Operating Margins.

(a) The Constraint Management target should be adjusted to reflect the provision of incremental capacity and any associated investment.

(b) For Shrinkage, Greenhouse Gas Emissions and Maintenance, the linkage to, and associated effects of, the TO plan are less clear at this stage. Where new assets are required to satisfy a customer signal, the growth in asset base will increase the volume of inspection and maintenance activities required. Additional network capacity will invariably drive different asset usage and maintenance schedules.

(c) For Operating Margins (OM), any changes in network topology will influence the requirement for OM. At this stage, however, we are proposing to pass through the costs of OM due to the requirement and market uncertainties. We aim to review this position following our current review of OM.

125 There is also a requirement for system access to enable completion and connection of new infrastructure relating to the provision of incremental capacity. We recognise this is a necessary activity relating to incremental capacity and are proposing that this cost should be considered in the incremental capacity revenue driver process. This interaction between the SO and the TO is explained further in Annex A ‘Buybacks / Constraint Management’ and Annex B ‘Delivering connections and capacity’.

Network Flexibility and Changing Operational Environment

126 Network Flexibility related investments have the potential to interact with a range of SO incentive schemes, including Constraint Management, Shrinkage and Maintenance, as well as schemes associated with management of the system.

[13] Prevailing obligated level of capacity is baseline capacity (as set out in the NTS Licence) plus any incremental capacity (for which the licensee has an obligation) and must take account of any substitution of capacity between points on the network.

127 Similar to the provision of incremental capacity, we have as part of the TO process, recognised the interaction between Network Flexibility and Constraint Management and are proposing that the two elements be explicitly linked.

128 Network flexibility is a requirement for additional operational capability driven by changing user behaviour and explicitly not the provision of incremental entry or exit capacity. Changing customer behaviours will place new demands on existing assets as we balance customer supply and demand requirements. As behaviours change and evolve, we anticipate that more frequent revisions to our mode of operation will be required which in turn may influence how we operate the system.

129 We expect to see a change in compressor running patterns at various sites with an increased frequency of stop/start operation and a subsequent change in the volume of gas evacuated from compression pipework and subsequently vented.

130 The anticipated increase in changing customer behaviour within the RIIO-T1 period is likely to reduce our window of opportunity in which to complete necessary works. We have already experienced increased summer flows from certain supply points which have shown little seasonal variation in their mode of operation, this in turn has created new challenges when attempting to schedule maintenance activities. It is possible that framework changes, new flexibility products and maybe new incentives could be required during the RIIO–T1 period.

Asset Health

131 Asset Health related investments have the potential to interact with the SO incentive schemes including Constraint Management, Shrinkage and Maintenance incentives.

132 The increase in planned capital investments together with the added complexity of changing flow patterns on the operation of the network will require us to be increasingly efficient in our delivery approach to system access. We have been developing our capability to improve our processes in this area throughout the TPCR4 period, ensuring we are able to create the required windows of opportunity to complete necessary maintenance and construction activities on our network whilst maintaining system availability. Through this enhanced capability, we plan to mitigate the impact of necessary system constraints and outages related to maintenance and construction activities.

133 For example, as TO we complete periodic inspections (e.g. in line inspections of pipelines (ILIs)) which allow us to determine the condition and integrity of our pipelines, enabling the continued operation of our assets by validating their reliability and allowing the re-declaration of their performance capabilities.

134 To ensure we are able to obtain the desired gas flows[14] on the day of inspection, we discuss with impacted network users[15] ahead of requirement to agree a suitable period in which to conduct the inspection and subsequent approach to manage their

---

[14] Inline Inspection (ILI) vehicles need to have a flow of gas in order to propel the vehicle through the pipeline and in some circumstances we need support from the upstream and downstream customers to create the required flow rate (this can be a requirement for either an increase and or reduction in the flow of gas).

[15] Entry and Exit capacity users. We have the right to call maintenance days on Exit capacity to allow the curtailment of flows without incurring costs, however, have no contractual rights to influence flows at Entry and any curtailments may lead to the need for constraint management actions.

individual requirements on that day (e.g. profiling capacity to catch up any reduction in flows). As SO we liaise with the customer on the day of inspection to optimise the control and speed of the ILI vehicles through the desired pipeline. We communicate with our impacted customers throughout the day in order to minimise the impact on their commercial operations during this procedure.

135 The majority of our secondary asset replacement work can be completed without an outage or flow / pressure restriction; however, there is work that will require pipeline pressure restrictions and outages over this period at entry and exit points.

136 We plan the majority of our work between the months of April to October when outages are more readily available, weather conditions are more favourable and the network is not fully utilised. Our stakeholders have already signalled that they would like increased flexibility on the way that NTS maintenance is planned and we expect customer behaviour to change in this area. This will reduce the window of opportunity in which to complete these necessary works. To better communicate and mitigate the impact, we will be articulating our maintenance requirements and activities to industry earlier to help determine the best way forward.

Investment to Comply with Environmental Legislation

137 Emissions related investments have the potential to interact with the SO incentive schemes, in particular Shrinkage, Constraint Management and Greenhouse Gas Emissions.

138 In formulating our SO incentive plan, we have considered the investment associated with environmental legislation including the transposition of the Industrial Emissions Directive into UK law. This has driven our compressor replacement programme and through Best Available Technique (BAT) we are obliged to deliver optimal investment solutions taking account of all factors including fuel consumption, and both combustion and vented emissions. The final design solutions will impact on many characteristics of NTS compressors

139 The likelihood of successfully commissioning multiple compressor units in one year is low without introducing material constraints on the NTS. The increased work volumes will increase the need for system access and outages, heightening the risk of physical constraints on our network. Consideration of the impact of this workload on constraint management costs is included within Annex A ‘Buybacks / Constraint Management’.

140 The compressor investment strategy therefore attempts to phase the construction and associated commissioning activities of new units across the programme, with due consideration to the geographical spread of any outages on the network within each year. Whilst the initiatives within the strategy will minimise the impact on the operation of the network, we will continue to refine the phasing of the works to ensure that we optimise the schedule over the RIIO-T1 period (as discussed in the ‘Buybacks / Constraint Management’ section of the ‘Managing Risk and Uncertainty’ Annex of our March 2012 RIIO-T1 submission.

Materiality of any Impact

141 We have already mentioned the inclusion of explicit adjustments in relation to network flexibility and incremental capacity provision. As we progress through the

RIIO-T1 period, the degree of interaction with our other incentive schemes will become clearer. However at this stage we expect the interaction to be limited. To the extent that significant interactions become evident, we would expect to utilise the adjustment mechanisms, target setting methodologies and various review points within the individual schemes to account for any material interaction.

Constraint Management

Overview

142 The principles surrounding the Constraint Management incentive scheme were set out in the 'Managing Risk and Uncertainty' Annex of our March 2012 RIIO-T1 business plan submission. Annex A of this document sets out these proposals in further detail and builds on the information contained within the March submission. For ease and completeness, a copy of the relevant details from our March submission has been included as Addendum 1 to Annex A so that readers can refer back to it if necessary.

Background

143 The existing capacity regime gives us an inherent level of constraint risk on the system to manage. The current regulatory and commercial frameworks oblige us on every day of the year to release obligated levels of capacity significantly in excess of peak demand at both entry and exit. Flows of gas commensurate with these levels of capacity cannot occur concurrently, so we take a view of the likely combinations of supply and demand patterns we could experience and an assessment of the most efficient solution to meet customer capacity requirements (consider the rules, tools and asset options available to us).

144 In the instances where we believe we cannot accommodate a user's flow requirements associated with booked capacity, we undertake constraint management actions in accordance with the UNC and System Management Principles Statement[16].

Developments expected over the RIIO-T1 period and TO plan interactions

145 There will be challenges going forward over the RIIO-T1 period driven by increased requirements for system access, driven by maintenance, Asset Health investment, statutory work (such as to comply with requirements under the Dangerous Substances and Explosive Atmospheres Regulations (DSEAR) and Industrial Emissions Directive (IED)), and construction activities relating to the provision of incremental capacity or Network Flexibility being envisaged. We propose to address each of these areas separately.

146 Our main focus has been on articulating the level of inherent risk which exists on the system based on the network topology and our capacity obligations and to that end we provide our current view of the quantification of this inherent level of constraint management risk.

147 The levels of required system access identified within the RIIO-T1 business plan (in terms of both the more traditional Asset Health work and the increased level of work due to environmental legislation, such as under IED) will impact on the forecast

[16] For details, see http://www.nationalgrid.com/uk/Gas/OperationalInfo/operationaldocuments/ProcurementSystemManagementServicesStatementsReports/doc_req_by_SCC8D/Stmt_Ent_Cap_Const_MGMT

constraint management costs and therefore we present our findings in this area in our proposed approach.

148 The potential levels of incremental spend which could be seen on the system due to either changes in the use of existing capacity (Network Flexibility) or requests for additional capacity (Incremental Entry and Exit) may also impact on our constraint management costs. Furthermore, we note the potential for material consequences on the constraint risk profile driven by European-led change (such as the Nomination rules under the EU Balancing code).

149 Given the uncertainty surrounding the requirements into the future, we propose that it is not reasonable to try to set ex-ante allowances to deal with these elements and that the effects on constraint costs should be explicitly considered as part of the relevant uncertainty mechanisms.

150 We have engaged with our stakeholders about our proposed incentives in relation to capacity management. The results of our stakeholder engagement have informed our thinking and helped us to develop our proposals for inclusion in this document. We will continue further engagement with stakeholders over the coming months in relation to the capacity regime and in line with our proposals for how uncertainty mechanisms will apply over the RIIO-T1 period. Whenever an uncertainty mechanism (such as in relation to the provision of incremental capacity) is triggered, a consultation will take place providing details of our preferred solution[17]. Therefore consultation relating to the appropriate constraint management target will be an ongoing process.

151 The main changes between our March 2012 RIIO-T1 business plan and this document are:

(a) We have decided not to pursue the introduction of ‘maintenance days’ for entry as we do not feel there is enough evidence to support these being introduced and stakeholders were generally not supportive of this proposal, but do consider that this should be kept under review during the RIIO-T1 period.

(b) We have updated the analysis in order to provide parameters for the relevant incentive schemes by carrying out analysis of additional years within the RIIO-T1 period and by considering the effects of unplanned maintenance on the forecast level of constraint risk over the RIIO-T1 period.

[17] In this case, our preferred solution will be based on the economic assessment of investment, commercial solutions or risk management as per the “Generic Revenue Driver Methodology” which itself will be subject to consultation.

Proposed Approach for Constraint Management

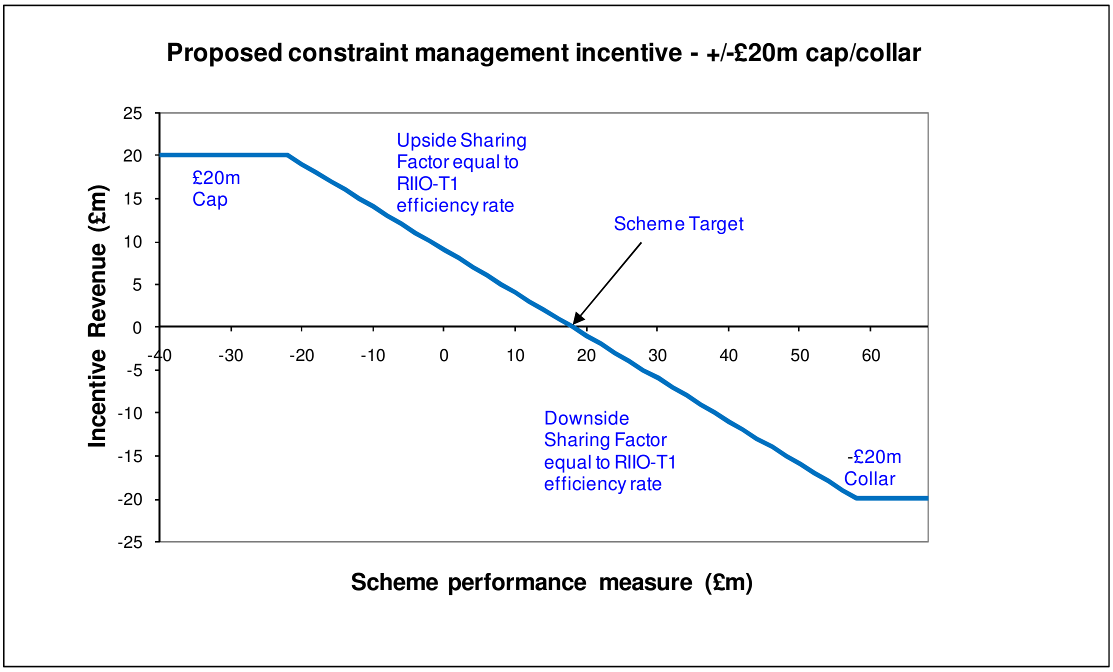
Structure

152 In line with our March 2012 RIIO-T1 business plan, we propose that the constraint management scheme should retain the same structure as the existing operational entry capacity buyback scheme, i.e. it should be a simple sliding scale incentive with an annual target, upside and downside sharing factors and a cap/collar. The scheme will include both costs and revenues associated with entry capacity and exit capacity (both operational and investment).

153 The performance measure for the scheme is the net position of the relevant costs to be included in the scheme less the relevant revenue terms, as indicated below:

Constraint Management Performance Measure = Relevant Costs - Relevant Revenues

154 The following illustrates how the scheme would operate in each year (based on the parameters suggested for the first year of the RIIO-T1 period):



155 Within our March 2012 RIIO-T1 business plan submission, we suggested that the target for the scheme should take account of four distinct categories of constraint management costs[18], and therefore be calculated as follows:

[18] For further details see paragraphs 70 to 77 of the 'Buybacks/Constraint Management' section of our 'Managing Risk and Uncertainty' annex of the March 2012 submission, which for completeness, is attached as 'Addendum 1' to Annex A.

Constraint management target	=	Ex-ante operational constraints	+	Ex-ante investment constraints	+	Incremental operational constraints	+	Incremental investment constraints

156 The 'Ex-ante' terms in the equation above are linked to the investments within the RIIO-T1 business plan for which we have asked funding to be provided as part of the settlement, whereas the 'Incremental' terms relate to the relevant uncertainty mechanisms. Within our analysis, we have assumed that the two incremental categories above are zero (as the uncertainty mechanisms are not yet in place) and therefore we would expect that the target will change over time as and when the uncertainty mechanisms are triggered. Hence our analysis has only considered the ex-ante terms above.

Proposed parameters

157 Our proposed scheme parameters (ex-ante target level, sharing factors and caps/collars) for the elements of the constraint management scheme in each year are as outlined in the Table below:

	Annual constraint management scheme parameters (09/10 prices)							
	2013/14	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21
Collar (£m)	-20	-20	-20	-20	-20	-20	-20	-20
Cap (£m)	20	20	20	20	20	20	20	20
Target (£m)	**17.9**	**24.5**	**21.1**	**27.1**	**21.6**	**18.5**	**56.7**	**24.3**
Sharing factors	RIIO-T1 efficiency rate 40%-50%							

158 As noted above, as we expect that the impacts of potential incremental capacity release would be considered by the application of the relevant uncertainty mechanism, we have not factored this into this analysis. We recognise, however, that before start of the RIIO-T1 period, the July 2012 exit application window and the March 2013 QSEC[19] auction could result in incremental capacity release which could lead to incremental constraint risk.

159 Within our 'Delivering connections and capacity' annex, we suggest that the existing arrangements could be amended[20] to cover the interim period until such time as the proposed change to the commercial regime in relation to connection and capacity processes may be implemented via the UNC governance process. If accepted, this change would also apply for the rollover year and therefore mitigates some of the

[19] Quarterly System Entry Capacity auctions are the annual auctions held each March for entry capacity

[20] Via either the revision of the existing permits scheme or by modification of the relevant methodology statements relating to the release of capacity

risks which relate to capacity release obligations within the March 2013 QSEC auction.

Scheme length

160 If our proposed approach to mitigating the risks associated with the March 2013 QSEC auction were to be agreed, we could set all the parameters of this scheme (including the target) for the first four years of the RIIO-T1 control period with the expectation that it would be subject to the mid-period review.

161 If this were not to be the case, due to the risks posed by the current arrangements concerning the March 2013 QSEC auction, we would propose that the target level for the scheme is only set for the first three years of the RIIO-T1 period as we would need to factor in potential risks from October 2016 onwards.

Proposed Approach for Transmission Support Services

162 We propose that there should be a separate incentive scheme to cover Transmission Support Services (TSS)21 (which are defined in our Safety Case as a substitute for pipeline capacity at high demands to support a 1 in 20 peak day). We currently have two different forms of TSS available to us; contracts under the Long Run Contracting Incentive and Constrained LNG (CLNG).

163 We therefore propose that the existing exit schemes entitled 'Long Run Contracting incentive' and 'Constrained LNG incentive' are merged to create a combined scheme in the RIIO-T1 period. This incentive should continue until the pipeline solution has been delivered to replace the Avonmouth LNG storage facility (proposed to be delivered in October 2018).

164 This is consistent with our proposal that an ex-ante allowance within the TO control should be provided to fund these investments. If this were not the case, then we would need this incentive to carry on into the latter years of the RIIO-T1 period.

165 As outlined within our 'Detailed Plan' annex of the March 2012 submission, we propose the following Transmission Support Services (TSS) annual target:

Incentive scheme	£m (2009/10 prices)	Sharing factor
CLNG	3.33 (2012/13 annual target)	100%
Long Run Contracting Incentive	3.90 (annual target starting Oct 2012)	50%
Proposed TSS annual target	**7.23 (RIIO-T1 period annual target)**	**RIIO-T1 efficiency rate 40%-50%**

[21] For details, see the 'Provision of Operating Margins and Constrained LNG for the South West' section of the 'Detailed plan' annex

Delivering Connections and Capacity

Overview

166 In order for a User to physically input gas to, or offtake gas from, the system, both a physical connection to the NTS and commercial capacity rights are required. These are applied for through two separate and distinct processes, which currently have no recognised formal interaction between them.

167 In order to obtain a physical connection, the customer enters into bi-lateral discussions with us. We then design, build and operate the connection facility, with the work fully funded by the customer. As each connection is different, the intermediate deliverables and therefore overall process can vary. It typically takes around three years to design and build a connection but this is dependent on the complexity of the specific project. Currently anyone can apply for a connection and the governance around the process is our obligation under The Gas Act 1986 (as amended) to comply with any reasonable request for a connection.

168 The processes for acquiring commercial capacity rights are governed by the UNC. Customers have expressed frustration that currently the connections process is ad hoc in nature and not subject to established timescales, milestones or costs. Customers have also expressed dissatisfaction with the capacity and connection processes being separate, saying that this makes these processes confusing and difficult to navigate. They wish to see both processes developed so that they are closer aligned, more transparent and more certain[22].

169 The introduction of the Planning Act has lengthened the time it will take to deliver incremental capacity (where reinforcement is required) and will drive higher costs into the earlier part of the process[23]. For any projects where a Development Consent Order is required we will not be able to deliver incremental capacity within the current obligated lead times. This therefore potentially exposes end consumers, NTS users and NGG to high constraint management costs, as we would need to buyback capacity rights in constraint situations where the customer has been connected in line with the obligated lead time, before network reinforcement has been delivered.

170 Our March 2012 RIIO-T1 plan included a number of proposals that would deal with the Planning Act whilst facilitating the overarching objective of delivering connections and capacity together, in the most efficient lead time, in a transparent and more certain manner.

171 Annex B – Delivering connections and capacity provides our updated thinking, following on from our March 2012 RIIO-T1 business plan, covering our regulatory change proposals, thoughts on the commercial regime, incentive proposals and options that could be implemented.

Background

172 Our RIIO-T1 business plan, submitted to Ofgem in March 2012, was based on a number of assumptions around the timing and likelihood of customer requests for

---

[22] Please see Appendix A to this document for an overview of the stakeholder engagement timeline on this topic.

[23] Please refer to our March 2012 RIIO-T1 business plan, Detailed Plan Appendix B paragraphs B16-B32 for more information of our understanding of the impacts of the Planning Act.

incremental capacity to facilitate expansions to existing, or the connection of new supplies and demands onto the gas NTS. In response to the uncertainty surrounding these assumptions, along with the need to mitigate the risk of long lead times introduced by the Planning Act (2008) ("the Planning Act") and progress customer requests to align the connections and capacity processes, our March business plan proposed a number of changes in relation to the release of incremental capacity[24].

173 The majority of the changes can be made to the regulatory framework through the NTS licence and are workable in their own right, with the exception of the proposal to reduce our obligated lead time to 24 months[25] to cover construction timelines only. Where a Development Consent Order under the Planning Act is required, existing obligated lead times cannot be met and therefore shortening the obligated lead time will only exacerbate the risk of not meeting the lead time. To manage this we are proposing that each customer wanting to signal either entry or exit incremental capacity would be required to enter into a bi-lateral contract (a Pre-Capacity Agreement "PCA"). This PCA contract would set out a timeline through to capacity release and therefore provide more certainty to project developers, with transparency of all the process steps and deliverables required from both parties. This would be accompanied by a phased user commitment that would ramp up in line with progression through the process culminating in full user commitment through a formal capacity signal.

174 We understand from our stakeholders that where they have entered into a PCA and undertaken the associated obligations (some of them financial), they would want assurance that the incremental capacity delivery they are underwriting cannot be allocated to someone else. A UNC modification would be required to facilitate this and we have therefore been developing and discussing these proposals with our stakeholders. Stakeholders share our view that it seems unlikely that any required UNC modification would be implemented by April 2013 (i.e. in time for the start of the RIIO-T1 period).

Proposed Approach

175 We have been working to develop alternative options that could be employed in the interim period to ensure that the commercial regime continues to interact with the regulatory regime appropriately. From all of the possibilities we have explored, there are two potential options that we are proposing could be utilised:

(a) controlling the release of incremental capacity through an amendment to the drafting of the relevant Methodology Statements, or

(b) continuing to use the existing permit scheme concept.

176 These two interim options allow the regulatory regime to interact appropriately with the commercial framework but, crucially, could not ensure the allocation of incremental capacity to the signatory of a PCA. This interim solution could endure if stakeholders do not require incremental release to be restricted to the signatory of a PCA, however if this is not acceptable, the UNC modification (or an alternate) can continue to be developed in parallel to industry timescales.

[24] Refer to our March 2012 RIIO-T1 business plan, Detailed Plan, Annex B paragraph B39 for more information.

[25] Our current obligated lead times are 38 months for the delivery of incremental exit capacity, from the July annual application window and 42 months for incremental entry capacity.

177 In conjunction with the above discussions, we have also engaged with our stakeholders about our proposed incentives in relation to the delivery of connections and capacity. The results of our stakeholder engagement have informed our thinking and helped us to develop our proposals for inclusion in this document.

178 In relation to the enduring solution that would apply if a UNC modification to align the capacity and connections processes were implemented:

(a) **We propose that a financial incentive is introduced to incentivise the early delivery of incremental capacity where the amended date for delivery of that capacity is valued by the customer, or penalise the late delivery of capacity (post the obligated lead time) if the amended date does not meet customer requirements**. This would contribute to the assessment of the risk / reward balance when considering whether to accelerate construction and deliver the incremental capacity early and also encourages us to release incremental capacity early where no construction is required. This scheme also penalises us where the capacity delivery is deferred and not in line with customer requirements, thus discouraging late delivery.

179 In order to ensure the regulatory and commercial frameworks work together appropriately from the beginning of the RIIO-T1 period, we are proposing two potential options that could be employed in the absence of a full UNC modification being implemented and therefore form an "interim" solution:

(a) **Control the release of incremental capacity through pre-requisites specified in the Methodology Statements[26].** Drafting could be incorporated into the Methodology Statements specifying that incremental capacity would be released with a 24 month lead time, from an October capacity allocation, where a PCA has been signed and all the relevant steps within that contract have been met. In the absence of a PCA a reasonable endeavours obligation would be in place; or

(b) **Continuation of the use of permits.** An allowance of permits could be provided to enable the lead time associated with the release of incremental capacity to be managed in the absence of a UNC modification. If this option was adopted we propose that a combined allowance across entry and exit of 7,804[27] permits (commensurate with the risk associated with our assessment of the customer projects likely to come forward) is provided to cover both for the rollover year and the first year of the RIIO-T1 period, with a value of £39.02m. Each permit would have the ability to delay one GWh/day of incremental capacity for one month at a cost of £5,000 each and permits could be earned for accelerating one GWh/day of incremental capacity for one month at a revenue of £5,000 each. We are prosing that we are allowed to go overdrawn by a factor of 50% (i.e. 3,902 permits) and that our financial exposure is capped at +£30m and collared at -£10m over the two year period.

180 In order to incentivise our other activities in the area of connections and capacity:

---

[26] The Incremental Entry Capacity Release Methodology Statement (IECR) and Exit Capacity Release Methodology Statement (ExCR).
[27] This would replace the existing allocation of 1,440 (GWh/month) permits on entry and 2,190 (GWh/d) permits on exit which currently apply for the rollover year.

(a) **We propose that a reputational reporting incentive is introduced in relation to the production of connection offers**. UNC modification 373[28], if implemented, will introduce formal timescales for the production of connection offers into the UNC[29]. Stakeholders wish to see how this process works in practice before any financial incentive is introduced in this area. We are therefore proposing that we publish information relating to the achievement of the key steps included in the UNC modification 373 process (including and in addition to the reporting requirements envisaged within the modification) in order to provide transparency to all and enable third parties to measure our progress.

(b) **We propose that a reputational reporting incentive is introduced in relation to our progression through pre-capacity application activities for incremental capacity release.** Stakeholders were supportive of our proposal that a definitive target should not apply to the time taken to progress through pre-capacity application activities, as this could reduce flexibility in an area where there is currently much uncertainty. We therefore propose that we report annually on the time it takes us to progress through the key milestones identified in the PCA contract, thus providing visibility to all parties and allowing our progress to be measured against others.

Further Information

181 The release of incremental capacity interacts with many of the System Operator (SO) external incentives; however as the connection and capacity activities are also strongly linked to the Transmission Owner (TO) function of the business, we have included the detail of our proposals in this SO submission, to be read in conjunction with our March 2012 TO RIIO-T1 business plan (Detailed Plan, Appendix B).

182 This information can be found in Annex B – Delivering connections and capacity.

[28] UNC Modification 373, Governance of NTS Connection Processes

[29] If UNC modification 373 is not implemented, we have indicated that we would still implement the principles.

NTS Shrinkage

Overview

183 The NTS Shrinkage scheme creates an incentive to minimise the costs of compressor fuel or energy which cannot be charged to consumers or accounted for in the measurement and allocation process. As shrinkage provider we are responsible for managing the end to end service of forecasting, accounting for, procuring and supplying energy to satisfy the daily NTS shrinkage components.

184 Since its inception in 2002, we have contained many risks inherent within the forecasting, procurement and daily balancing activities significantly reducing costs for the benefit of the industry. Going forward, a number of variables will affect shrinkage requirements. These include changes in energy supply and demand patterns requiring greater network flexibility, the plan for electrification of compressors to replace compressors and our requirement to comply with the Industrial Emissions Directive (IED).

185 We are concerned that forecasting underlying volumes over the entire RIIO-T1 period at this stage could lead to windfall gains / losses. We are also concerned that this will exacerbate financial risks that arise from trading out the inherent and significant variance between underlying requirements and daily outturns.

186 In response to our analysis and through consultation with our stakeholders, we propose to retain the existing annual cost minimisation scheme, derived from energy targets and forward wholesale gas and power prices. To accommodate uncertainties and reduce risk for consumers, energy targets will be derived within each incentive year using robust statistical modelling and methodologies. A 50% sharing factor has been adopted, with a +/-£10m cap / collar.

Background

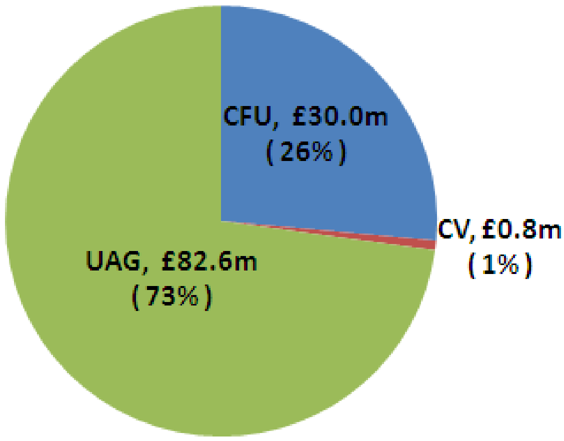
187 NTS Shrinkage is an underlying energy requirement comprised of compressor fuel, Calorific Value (CV) shrinkage, and Unaccounted for Gas. Depending on the wholesale price of gas and the outturn volume requirements, it costs customers around £100m a year.

188 Although significant it is very low relative to the value of energy being transported and the commercial and safety implications of operating the high pressure NTS.

189 The following illustration shows the relative proportion of each component as forecast for the 2011/12 incentive year.

Incentive Year 2011/12

Indicative value of NTS Shrinkage components, £m



190 The NTS Shrinkage scheme incentivises us to minimise costs by efficiently undertaking all activities necessary to physically and financially fulfil our daily energy requirements including;

(a) Managing the uncertainty in each component part of shrinkage by accounting for and forecasting underlying long term requirements, short to medium term deviations, and daily outturn energy requirements

(b) Forward procurement and rebalancing of energy requirements in the forward and prompt markets

(c) Managing the gas and power regime's balancing and delivery risks; and

(d) Providing financial settlement and credit risk management

191 Performance is measured through the use of a cost target with two constituent parts (a price target and a volume target) by reference to efficient benchmarks. Currently the underlying gas and electricity requirements (the primary cause of costs) are forecast ex ante and benchmarked to forward quarterly and monthly market prices which are the second largest driver. To address uncertainty in forecasting targets ahead of delivery, the ex ante energy requirements are adjusted ex post to better reflect outturn. Uplift allowances for 'swing' and other ancillary costs are also included.

192 The current NTS shrinkage scheme is subject to a cap of £5m and a collar of -£4m, with upside sharing factors of 25% and downside of 20%. After accounting for extraneous events, we have typically delivered benefits of between £20m-£30m per annum for consumers.

NTS Shrinkage Components

Compressor Fuel Use (CFU)

193 Energy, in the form of gas or power is consumed by compressors when gas is transported across the NTS.

194 The amount of energy required each day depends on customers' demands for gas, transit flows through interconnectors, optimisation of CV losses, and the location at which supplies are delivered to the NTS. In the longer term, the electrification of compressors will also impact.

195 The primary driver of historic CFU is the location at which supplies were brought into the NTS. The most significant input point being St Fergus. As a result, ex post adjustments have been applied to reflect outturns at St Fergus.

196 However this underlying relationship masks the inherent volatility caused by other factors including weather sensitive GDN demands, the scale and volatility in industrial loads, storage cycling, interconnector flows, and how gas fired power generation is used to satisfy baseline demands or support renewable generation.

Unaccounted for Gas (UAG)

197 Unaccounted for Gas (UAG) is energy which cannot be attributed after accounting for all measured inputs and outputs from the NTS including compressor fuel, CV shrinkage, and measured changes in line pack. The primary driver is the technical tolerances of flow metering and CV measurement assets typically owned and operated by third parties and meter errors.

198 It also occurs where measurement equipment fails to operate within tolerance and this cannot be established or corrected within the gas flow allocation timescales.

199 The underlying level of UAG tends towards a net loss of energy. By its nature it is very unpredictable, resulting in daily energy gains or losses which unfold as trends over short periods in time. It is currently the most significant element of NTS shrinkage, although this hasn't always been the case.

200 From 2009 onwards, UAG has been subject to an outturn, or ex post, energy target, recognising the volatility of this component of NTS Shrinkage and a separate incentive. From 2012/13, UAG is also subject to a reputational incentive.

"This subject is in need of a full, independent perhaps Ofgem-led industry review. Previous SO incentive arrangements appear to have missed the mark in achieving any marked improvements and until the root causes are properly and transparently identified, it seems inappropriate to consider incentives."
EON's response to National Grid's consultation, May 2012

201 Further detail on details how we propose to manage and improve UAG levels and the consequential costs for our customers can be found in the UAG section.

Calorific Value (CV)

202 Calorific value (CV) is a measure of a fuel's energy content with supplies into the gas transportation networks (NTS & GDNs). To comply with current regulations, gas must have a CV ranging between 36.9 and 42.3 MJ/m^3.

203 To comply with the Gas (Calculation of Thermal Energy) Regulations 1996 (amended in 1997), CV shrinkage arises when energy cannot be billed to consumers due to CV differences across Local Distribution Zones (LDZ).

204 Beyond the inherent comingling of supplies as they are compressed, transported and routed through the NTS, the cost of compressor fuel and topography of the network severely limits our ability to economically reduce CV shrinkage.

Consumer risk from uncertainties under the existing scheme

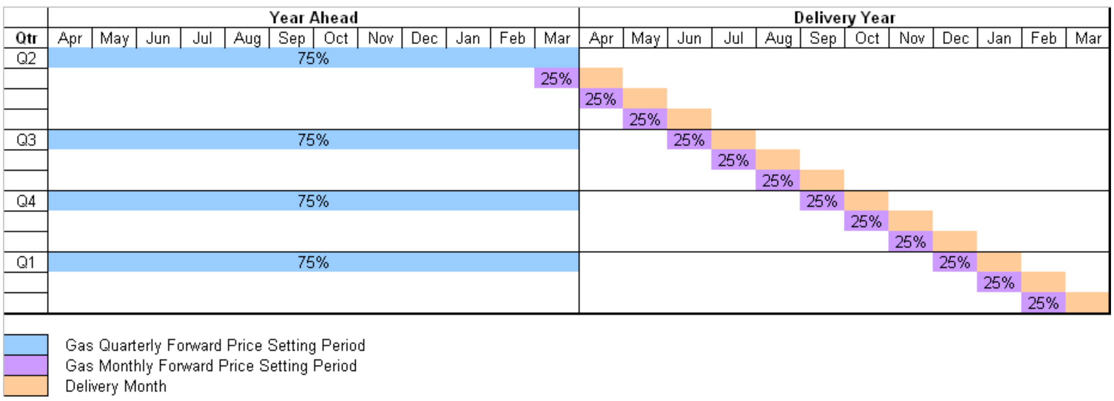
205 Outturn requirements for NTS Shrinkage vary each day, diverging significantly from the modelled long run average.

206 The variance between the energy bought in forwards markets for long run average requirements (and outturn needs) creates two elements of risk for consumers. The costs of providing swing to satisfy daily variances from flat monthly blocks of gas, covered by the swing uplift target, and the profits or losses arising when trading out the energy forecast error in different trading periods with different values for gas.

207 For example, in 2009/10 the change in UAG volumes from forecast levels (4000 GWh) and change in price (40p/therm) led to a windfall of c£55m revenue for customers.

208 Whilst this example demonstrates where customers have benefited, trading losses are equally as likely. A review of variance between outturn energy requirements and ex ante energy targets occurring between April 2002 and March 2012 identifies a potential £3m to £15m cost movement per quarter for every 10p/ therm price change.

209 The following table illustrates the time difference between procurement target and delivery periods.



210 It shows how baseline gas requirements are incentivised for procurement up to 2 years ahead of the point of delivery. The year ahead price reference period is shown in blue, month ahead price reference period is shown in purple, and time lag to physical delivery periods illustrated in orange.

211 Recognising the uncertainty in underlying energy requirements, the current incentive makes ex-post adjustments to the targets of CFU, UAG and CV. This ensures our

risks and rewards are contained to the benefits we deliver in managing actual requirements rather than forecast errors.

212 However, this has created an inefficient incentive whereby we are rewarded or penalised for trading out energy errors when the market value of gas has changed from the original procured value. By adjusting the requirements ex post, and not the price benchmark the incentive is inconsistent and does not accurately measure any benefits or efficiencies achieved in reducing the risks by re-forecasting or trading out the error efficiently relative to the market.

213 Importantly, experience has shown that customers face a material risk of significant trading profits or losses being incurred each year. We propose to minimise this risk by better aligning energy purchases and price benchmarking to periods of greater forecast certainty, and removing the inconsistency of adjusting energy volumes and not price targets.

Developments expected over RIIO-T1 period and TO plan Interactions

214 A number of changes expected over the period will impact on shrinkage calculations and outturn position.

215 A reliance on gas imports has created unprecedented supply diversity across the NTS. Going forward, both supply and demand diversity are set to increase as the industry responds to the challenges of supporting more variable renewable forms of power generation, and securing gas supplies from increasingly competitive global markets. These changes are likely to require greater network flexibility, flow increased volatility, and new drivers for compressor fuel requirements.

216 The drive for sustainable fuel supplies is forecast to increase the level of new supplies including biogas and coal bed methane. Technological developments have also enabled shale gas to be economically extracted and supplied to global markets. All of these have the potential to affect CV diversity and the scale of NTS CV shrinkage losses.

217 Legislative requirements to limit emissions from combustion have resulted in an ongoing programme of compressor investment including electrification of certain units.

218 We also expect the cost of electricity supply contracts and charges to evolve over the RIIO-T1 period in response to market conditions and regime developments such as the Electricity Market Reform.

219 Against the backdrop of these uncertainties, the NTS shrinkage incentive needs to evolve.

Proposed Approach

Stakeholder expectations

220 Over the RIIO-T1 period, shrinkage is expected to remain a significant energy purchase with costs sensitive to the daily requirement for energy and its financial value. The SO remains best placed to manage these costs and risks given our

holistic overview of shrinkage components and system utilisation which enables us to model, forecast, control and manage energy usage, and procure efficiently.

221 Engagement with stakeholders has confirmed that cost minimisation should remain the fundamental objective of the scheme, with sharp but fair incentives to manage both costs and risks. Our stakeholders also value forward purchasing as a means of spreading price risks.

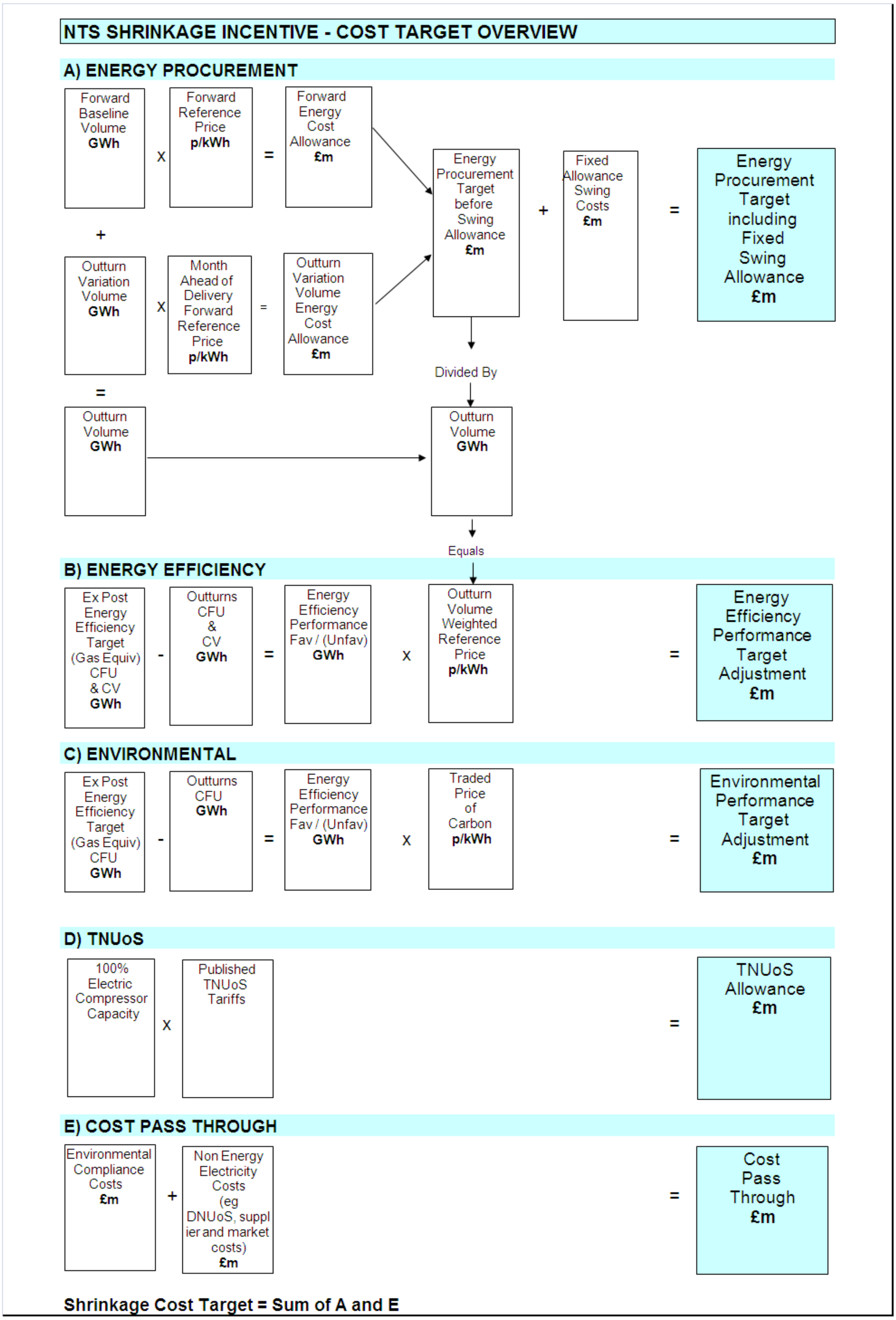
222 Stakeholders also recognise the scale and uncertainty of shrinkage requirements requiring an incentive on us to forecast accurately, procure efficiently and to reduce compressor fuel usage without impacting network security.

Proposed Approach - Objectives

223 We propose to retain the scheme encouraging us to minimise the cost of gas and power shrinkage energy. We will derive an annual cost target from wholesale forward price targets applied to energy targets. To sharpen the overall incentive on us we propose to widen our existing sharing factors, caps and collars. Our exposure should be aligned with TO incentives to ensure we manage the impacts of commissioning and operating new compression assets.

224 We propose to accommodate uncertainty over the 8 year period and minimise trading risks by building upon the current target setting methodology, and consult with our stakeholders on any changes we may propose annually. Further detail on trading risk can be found in Appendix 1.

225 The proposed scheme form is summarised below:



226 We will align the price reference periods for gas and power using periods in which both products are traded liquidly. We will retain uplifts for ancillary costs incurred above wholesale forward prices, and make them more reflective of the actual costs incurred.

227 We propose to sharpen the energy efficiency measure to focus the incentive on reducing energy consumption and CV losses.

Scheme Parameters

228 We propose an annual incentive within an 8 year framework. This approach enables clear visibility for stakeholders on shrinkage performance and allows the costs and incentive performance to be targeted the shippers in the market in that year. Our customers have said that stability in their charges is important. By accounting for the incentive performance in the same year as the shrinkage costs, this would also act to dampen the volatility in charges.

229 As this is a relatively mature incentive, designed to cover the aspects of Shrinkage over which we have a reasonable level of control, we feel that it is appropriate to increase the sharing factors to 50% from 25% upside and 20% downside. This would sharpen the incentive to reduce costs below target, align incentives between the SO and TO. The symmetrical sharing factors would mean that any deviation from the target, whether out- or under-performance, would have the same value.

230 To maintain the range of costs over which we are incentivised, we also propose to increase the caps and collars to +/-£10m. This will maintain an incentive over a £20m range around the target.

Energy Targets

231 A price reference sets a benchmark price against which our performance can be compared. This benchmark that can be made up of a various traded energy products in a set timescale. By trading the same products in the same timescale (the price reference period) as the price reference, we should be able to achieve neutral[30] incentive performance.

232 Contracts with shorter timescales between the procurement and delivery (use) of energy are often referred to as prompt and longer timescales as forward contracts. Prompt prices are generally more volatile, as the market reacts to the conditions at that time. Trading over a longer period using forwards contracts means that there is more time for the price of gas to rise and fall allowing for potential trading opportunity. However, further ahead of time, our forecast energy requirements will be more uncertain.

233 Stakeholders have stated they would prefer a mix of forward and prompt energy procurement as a way of spreading price risks.

[30] We may not be able to follow the reference perfectly as this would entail trading on each trading day at exactly the price reference on the day which may not be practical, partly due to the size of our energy portfolio requirements.

234 We propose to publish and consult upon an updated methodology statement[31] for each incentive year to derive the energy volume target for compressor usage and CV shrinkage.

235 Ahead of each quarterly price reference period, we would reforecast each of the shrinkage energy components using prevailing data inputs and the methodology. We will then publish an updated ex ante quarterly energy target.

Price Targets

236 Price targets set an efficient price benchmark for purchasing the energy targets. We propose to align the price reference periods for electricity and gas to reflect the changing mix of compressors, i.e. gas and electric, and therefore the need to procure a mix of energy sources.

237 Set in a forward window to spread the effects of movements in commodity values, prices will be determined for each quarterly energy target using the average reported price over the preceding 9 month window in which it is traded.

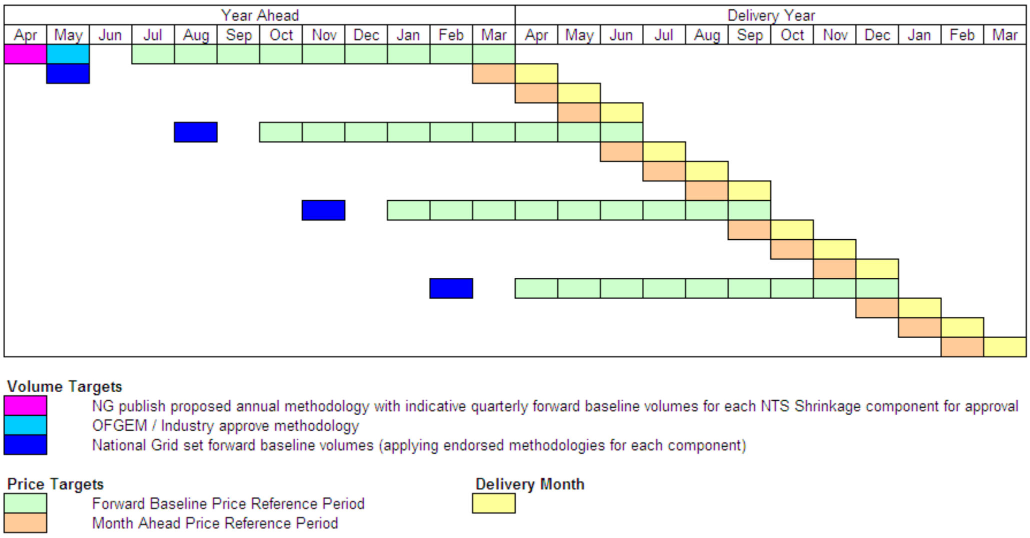
“We therefore believe that the baseload shrinkage procurement should be indexed to a mixture of year, quarter and month ahead prices to minimise costs to consumers.”
EDF’s response to National Grid’s consultation, May 2012

238 The price target will be adjusted to reflect any adjusting trades arising from the ex post energy requirement deviating from the ex ante quarterly energy target. In practice, this means applying the average reported month-ahead price to the deviation (ex ante quarterly energy target adjusted ex post for outturn in each month within the quarter). Further detail is contained within Appendix 2.

239 The proposed timetable for the methodology consultation, along with energy target publication and price reference periods are shown below.

31 The annual published methodology would detail how statistical modelling is used to forecast each of the NTS components reflecting outturn requirements and trends, prevailing supply / demand forecasts from Future Energy Scenarios (FES) consultation, and updated compressor electrification programmes and maintenance plans.

NTS Shrinkage component	Proposed methodology based upon
Compressor Fuel Use (CFU)	CFU Modelling - using a St Fergus multi year regression model
CV Shrinkage (CV)	Network Modelling Analysis
Unaccounted for Gas (UAG)	Latest 90 day average of Assessed UAG levels



Other costs

240 The reference price methodologies assume that gas and power shrinkage energy requirements are flat within each quarter of a year. Given the extent of daily variance and the risks arising from half hourly or daily imbalance cash-out, a means of economically providing swing is fundamental to managing overall costs.

241 We are incentivised to manage the risks and reduce swing costs through a target uplift (£/unit) from the underlying forward price target. The uplift was derived from a forecast of costs spread over the underlying forecast energy requirement. However experience has demonstrated that the forecast error gives rise to a windfall loss or gain, arising from over or under recovery of swing costs.

242 To avoid this we propose an annual fixed cost target swing allowance rather than a unit price. In order to address uncertainty in swing requirements, the annual swing cost forecast will be included as part of our published updated methodology statement[32] ahead of each incentive year.

243 Further details are included in Appendix 3.

Electricity Charges

244 In addition to baseload and swing energy costs, electricity procurement via a retail contract attracts supplier, market and distribution network costs over which the NTS Shrinkage provider has no direct control. These supplier and market costs include those associated with Feed-in Tariffs, Meter Reading, Balancing Service Use of System Charges (BSUoS), Transmission and Distribution Losses, (DUoS and TNUoS charges), and are captured as part of the electricity retail uplift in the current incentive.

[32] The annual published methodology would detail how statistical modelling is used to forecast each of the NTS components reflecting outturn requirements and trends, prevailing supply / demand forecasts from Future Energy Scenarios consultation, and updated compressor electrification programmes and maintenance plans.

245 In principle, we should continue to be incentivised on elements of electricity charges where we have direct control, i.e. baseload / swing energy costs and TNUoS charges. We should be financially neutral to all other items, with cost pass through for such items minimising the incentive impact of future market developments over which the NTS Shrinkage provider has no control.

246 As Electricity contract charges (market and supplier charges) are all outside of our control and derived from contracts procured openly and efficiently through competitive tender, we propose a pass through arrangement for such charges.

247 For TNUoS and DUoS charges, we propose to retain the current incentive arrangements with an annual update of charge rates (as published by the relevant party) to derive target costs.

Environmental Costs

248 Through this aspect of the incentive we propose to incentivise the efficient use of compressors and economic reductions in CV shrinkage. The Traded Price of Carbon represents the UK Government's approach for the market valuation of emissions and the economic cost of mitigation.

249 Under the current NTS Shrinkage incentive, the cost of carbon is factored into the incentive target through a Traded Price of Carbon Adjustment (TPCA) whereby there is a reward if actual compressor fuel use is less than the adjusted target or penalty where it is more. To achieve this, the overall NTS Shrinkage cost target is increased or reduced by the financial value of the calculated TPCA.

250 In doing so, the TPCA incentivises us to lower gas consumption through a strong price signal, aligning with the UK government's emissions valuation methodology.

251 A range of environmental schemes are in place that could change over time and lead to inappropriate incentives where emissions prices are different for gas and electricity use. Simplification of the impact of these schemes, through use of the government's Traded Price of Carbon is proposed to ensure a consistent incentive throughout the RIIO-T1 period.

252 The current NTS Shrinkage incentive allows a pass through of costs incurred in relation to the Carbon Reduction Commitment Energy Efficiency Scheme (CRCEES). Consistent with this, it is proposed that incremental costs associated with EU ETS compliance should be passed through within the NTS Shrinkage incentive.

253 We do not propose to change the current mechanism for recovering environmental charges associated with outturn compressor fuel requirements adjusted for efficiency targets as described below.

Energy Efficiency Targets

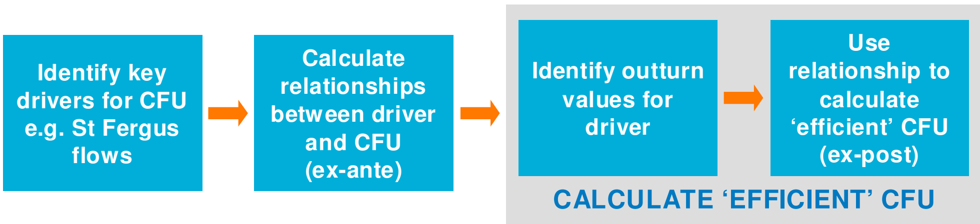
254 The ex post adjustment of energy costs will sharpen the incentive to procure energy efficiently. Similarly, it is also important to maintain an incentive to achieve an efficient level of CFU and CV shrinkage.

255 It will be challenging to determine the optimally efficient compressor fuel level given transient supply/demand flows, the routing of gas necessary to fulfil capacity obligations and a requirement to accommodate both NTS and interconnected networks' maintenance and investment programmes.

256 It is possible for network analysis to model an efficient level. We are currently developing prototype network modelling tools which may offer future capability in this area, but this would require many years of development.

257 Until such IS capability becomes available, we propose to use regression analysis to determine an efficient level of compressor fuel energy consumption. We will to publish and consult upon the regression analysis as part of our annual energy target methodology review.

258 The diagram below illustrates the proposed approach to setting an ex-post target, with the subsequent table identifying the levels of potential sophistication.



259 The table below summarises three practicable options for calculating the volume and ex-post targets deemed efficient levels. These examples are based on the assumption that St Fergus inputs remain the strongest statistical driver of CFU, but this will be reviewed and adapted in line with the energy target setting methodology. Further detail in contained within Appendix 4.

	Relationship with CFU	Ex-ante Procurement Target	Ex-Post Efficiency target	What need to codify?	Comment	Opinion
A	Best-fit line for annual or quarterly average St Fergus flow versus CFU Set for 4 years	Use best-fit line and FES forecast of St Fergus flow Set for 4 years	As ex-ante but with outturn St Fergus flows Set for 4 years	Numbers	Simplest Would not correct for NTS/flow changes	Not robust enough for 8 years – maybe for 4 years though
B	Best-fit line for annual or quarterly average St Fergus flow versus CFU Update each year	Use best-fit line and FES forecast of St Fergus flow Update each year	As ex-ante but with outturn St Fergus flows Update each year	FES St Fergus forecast How to calculate best-fit line	Simple Updates each year for NTS/flow changes, albeit with 1-year lag	Best option, especially if have 4-year review for post-event network analysis
C	Multi-ASEP regression Update each year	Use regression coefficients and FES forecast	Use regression coefficients and outturn driver data	FES ASEP forecasts How to calculate regression coefficients	Difficult to codify regression Similar performance to simpler methods No more robust than simpler methods, especially if codifying	Complicated to codify for little/no benefit

260 To improve the incentive on us to reduce compressor fuel we propose to use Option B.

261 We will calculate an efficient target for CV shrinkage using network analysis from outturn network flow data.

262 Having adjusted the updated quarterly energy targets ex post to reflect the outturn energy requirements of each component part of NTS shrinkage, we propose to make a further adjustment reflecting the deemed efficient use of compressor fuel and CV shrinkage.

Delivering Benefits for the Consumer

263 We support our stakeholders' views that the scope of the cost minimisation incentive should remain broadly unchanged, with developments to limit risks and provide sharper incentive to manage elements within our control and have proposed changes which are consistent with their views.

264 The table below provides a high level summary of these proposed changes

Area	Change Proposed	Customer focussed rationale
Price reference periods	Rolling 9 month price reference period ahead of the delivery quarter Aligns gas and electricity reference periods	Set the benchmarked price for energy purchases to the forward market's value. Spreads price risk over time Limit potential for windfall gain / loss Period of liquid trading

Forward baseload procurement	Energy targets based upon prevailing forecasts, and methodologies which keep pace with uncertainties over the 8 year period Cost performance measured on energy outturns and benchmark quarterly & month ahead price	Incentives targeted on factors driving controllable costs Recognise significant uncertainty in daily energy requirements, require transparency in forecasting and data modelling Minimisation of trading risk Minimisation of exposure to cashout and prompt markets
Swing Management	Methodology to determine annual swing requirements and fixed target costs allowance	Limit potential for windfall gain / loss through over / under recovery of swing costs. Incentive to reduce swing costs
Environmental	Single environmental performance measure based upon Traded Price of Carbon to ensure consistent incentivisation	Strong price signal which aligns operational behaviours to cost / environmental benefits of energy efficiency
Pass through principle The SO should not be incentivised on those costs over which the NTS Shrinkage provider has limited or no control	Electricity Incentivised to minimise energy costs (baseload and swing) and Transmission Network Use of System (TNUoS) charges and be financially neutral to components procured through open market tenders. Environment We should be incentivised by the Traded Price of Carbon (as outlined above) and be financially neutral to other environmental schemes e.g. CRCEES and EU ETS.	Focuses attention on components over which National Grid can exert real control Allows a consistent incentivisation approach to be adopted for RIIO-T1 period
Incentivising Compressor CV shrinkage Energy Efficiency	Alternative performance measures proposed	Opportunity for efficiencies is small, with considerable wider impacts but operational behaviours should reflect benefits of energy efficiency

265 Whilst our package of proposals considerably sharpens the incentive on us to reduce costs and risks within our control, it does not materially change the underlying risks we are managing on behalf of customers.

266 We believe these proposals build upon the proven NTS shrinkage framework and provide a sharper incentive on us to minimise costs, reduce risks and accommodate uncertainty on behalf of customers. They reflect a challenging but fair balance of risk / reward in managing the activities associated with NTS shrinkage.

Unaccounted For Gas

Overview

267 UAG is that energy which remains unallocated after accounting for all measured inputs and outputs from the NTS, Own Use Gas consumption, CV Shrinkage and the change in NTS linepack. The primary causes of UAG are the inherent measurement tolerances and errors associated with entry and exit metering equipment.

268 In our role as system operator, we are able to undertake work that seeks to minimise UAG. Through a range of agreements we have rights to witness meter validation activities, and have an overview of all the component data that makes up UAG.

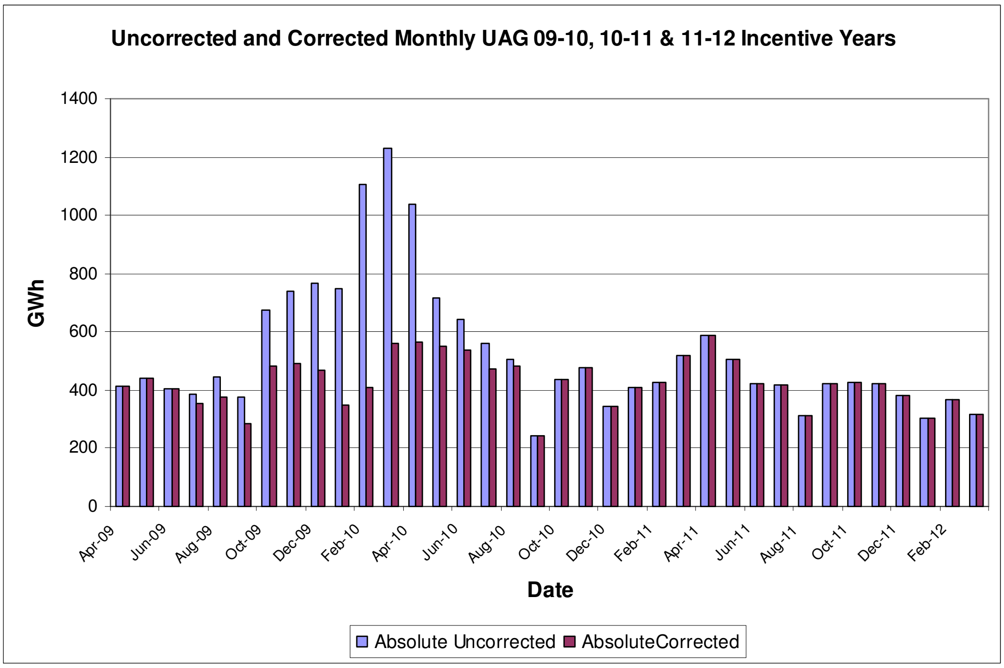
269 Stakeholders are concerned about the current level of UAG and a number have said that NGG, because of its unique position in the industry, is the only organisation that can work with the parties involved to address this issue. A number of stakeholders told us they would have like the UAG incentive to be financial rather than reputational.

270 The system operator does not have direct control over the levels of UAG within the NTS and for that reason a financial incentive on managing these volumes is not appropriate. However, we do recognise that we are in a position through our access to meter validation records and UAG component data to undertake analysis on the data which may identify potential issues on metering equipment, and to share this data with meter owners in order that they can eliminate or minimise these sources of UAG. Therefore, we continue to propose a reputational incentive in line with that which was implemented for the 2012/13 period.

Background

271 National Grid in our role as NTS shrinkage provider procures UAG on behalf of the community. In 2011/12 the absolute volume of UAG was 4,925 (GWh). The cost of buying UAG was £83m in 2011/12 and these costs are paid by shippers through the SO commodity charge. The existence of UAG in some circumstances may be an indicator of a misallocation of costs until such time as meter reconciliation occurs in accordance with UNC processes. The primary causes of UAG are the inherent measurement tolerances associated with entry and exit metering equipment. The permitted tolerance for fiscal metering equipment connected to the NTS at entry is plus or minus 1%; for exit meters, the tolerances vary and are set out in supplemental agreements. UAG was approximately 0.5% of throughput during the last financial year.

272 The chart below shows the level of UAG during the last 3 years. It compares the measured UAG with corrected UAG; corrected UAG takes account of known meter errors.



273 It can be seen that the level of corrected UAG has stayed broadly within the same range over the three year period. Clearly the uncorrected level varied significantly; this was due to two meter errors, as described below.

Previous incentivisation and work to identify UAG

274 For the period April 2009 to March 2012, a financial incentive based on outturn UAG has been in place providing an incentive payment when UAG was reduced below a target figure. In practice, the levels of UAG exceeded the target so that no incentive payment was made.

275 Under the incentive, a project was put in place to establish rigour around the investigations into UAG. This resulted in a number of areas being progressed and during 2011 an open letter[33] was sent to Ofgem, shippers, suppliers and all interested parties on the findings of this project.

276 This project reviewed a number of areas, including the linepack model, data quality and data centred investigations, meter validation witnessing and various strands of research. It concluded that there was an underlying inherent level of UAG on the NTS, and initiated a piece of research to try to understand what that level was. It also recognised that it was important to work more closely with meter owners as meter errors are the most likely source of UAG.

277 The two most significant causes of UAG that have been identified during the last three years have been significant meter errors at Aberdeen and Braishfield offtakes. Ideally, data mining techniques would identify meter errors when they occur, thus focussing investigation work and minimising the duration of the error.

278 The data mining tool that was in use during 2010 successfully identified the Braishfield meter error shortly after it occurred, and we worked closely with SGN

[33] We published an UAG industry update on 20 June 2011 at http://www.nationalgrid.com/uk/Gas/soincentives/SupportingInfo/

during the initial stages when this had been flagged by the data mining tool as a potential issue.

279 However the same data mining techniques did not identify the Aberdeen meter error. Since that error was identified, different techniques have been adopted and put in place. However this does highlight the fact any single technique is not on its own guaranteed to find all meter errors, and should be used in conjunction with other techniques in order to ensure investigations are focussed appropriately.

280 For the consultation period, both financial and reputational incentives were considered. For any financial incentive to work appropriately, an appropriate target is required to ensure that the incentive remains effective. When consulting on the incentive for the rollover period, it was noted that there were difficulties in determining underlying drivers for UAG which meant it was difficult to set an appropriate target. It was also noted that the annual target was exceeded well before the end of the performance year which could have the effect of creating a disincentive to carry out any further work.

281 A new licence obligation following industry consultation was introduced, requiring us to undertake certain work related to UAG.

282 The new licence condition[34] came into force on 1st April 2012 which required us to.

283 The activities that we are currently undertaking can be summarised as follows:

(a) Witnessing meter validations in accordance with a rolling programme;

(b) Undertaking data centred investigations with a view to focussing efforts on sites which may be causing UAG;

(c) Undertaking research to try to establish what the underlying level of UAG on the NTS could be expected to be; and

(d) Working closely with meter owners when potential issues are identified to ensure a common understanding of issues and impacts.

284 All of these activities will be reported on in accordance with our licence obligations and, we propose to hold a stakeholder event annually in the future to explain our activities further. The first report is due to be published in August 2012.

285 Meter validation witnessing involves us attending sites during meter validation activities carried out by meter asset owners. This provides a level of confidence that individual meters are maintained in line with prescribed standards so that the expected levels of uncertainty are met and not subject to operational bias. These activities form part of the regular maintenance cycle and we consider that exercising our rights to witness will remain an appropriate control over the course of the RIIO-T1 period.

286 We have developed a range of data centred investigation techniques which have the potential to identify meter errors which are contributing to levels of UAG. The methods range from simple trend plotting and identifying excursions from expected

[34] Special Licence Condition C29

patterns, to complex data mining techniques involving large datasets. Our evaluation of particular methods may eliminate them as candidate techniques and, where this is the case, we are required to include this within our licence reporting. We recognise that this area is one where we are endeavouring to create new control mechanisms which mean there is an uncertainty of outcome. Therefore, we would recognise that there should be a review of outcomes during the incentive period.

Developments expected over RIIO-T1 period and TO plan Interactions

287 Areas of further work are expected to include an assessment of metering tolerances and whether tightening the tolerances would contribute significantly to a reduction in UAG, and an assessment of the performance of certain types of meter in different conditions. Although we will undertake this work, any proposed changes in these areas could require change to the commercial and regulatory contract (a UNC mod industry debate), which we would expect to bring forward under this reputational incentive.

288 It is worthy of note that for Gas Distribution Network Operators (GDNs), a new reputational incentive has been proposed in relation to offtake meter errors in the RIIO-GD1 business plans. It is proposed that there will be an output measure in relation to the number of meter errors on the network and the time taken for the GDNs to respond to it. This output measure is for the GDNs to report meter accuracy on a timely basis and is an obligation to report meter validation errors as soon as they are discovered.

Proposed approach

289 Stakeholders are concerned about the current level of UAG. Whilst they acknowledge this is due to meter errors occurring on meters which do not belong to us a number have said that, given our position in the industry, we are the only company that can coordinate the work required to address this issue.

"Even though NG does not own all the meters it does have access to the metering data such that some kind of incentive on metering accuracy could be appropriate to avoid a recurrence of the current spate of metering errors, which has resulted in significant reconciliation events for the affected Shippers."
Energy UK's response to National Grid's consultation, May 2012

290 A number of stakeholders would like a financial UAG incentive. For a reputational incentive to work one stakeholder said it will require clear, open and transparent publication to the industry.

"This will ensure that the reputational incentive will act as envisaged by creating a good or bad reputation for those transporters who are not managing their meters and UAG adequately."
EDF's response to National Grid's consultation, May 2012

291 The infancy of the current reputational incentive means that it is too early to determine its effectiveness in comparison to the previous financial incentive.

292 We propose a reputational incentive for the 8 year period based on the current rollover incentive whereby we continue to witness meter validations, complete data centred investigations and work with meter owners as potential issues are identified.

We propose to report on these activities and investigations. We propose that twice yearly reporting be included as a requirement within the incentive. We acknowledge that it is appropriate to include a review of whether the scope of activities remains correctly focussed during the period of the incentive.

293 Where our activities described above lead us to draw conclusions about the contributing factors to levels of UAG, such as might derive from the asset population or standards applied to design or maintenance, we expect to share these with the community as part of our incentive reporting.

Delivering Benefits for the Consumer

294 We as shrinkage provider recognise that UAG has become the most significant component part of NTS shrinkage. We do not have direct control over the levels of UAG deriving from either the inherent uncertainties of metering systems and errors introduced into metered values. However we recognise that as a party to all the agreements and as a recipient of component data, we are in the best position to apply analysis to this data and to share the results of this analysis with the meter owners and, where required and appropriate, the wider community. This approach should serve to keep levels of UAG down and hereby mitigate risk costs to shippers which could be passed on in turn to consumers.

295 Our proposal is designed to ensure we continue to exercise our contractual rights and central access to data in the interests of controlling levels of UAG and thereby costs of shrinkage gas procurement. Whilst recognising the limited extent to which we have direct control over the causes of UAG, it is framed within our view of our role as System Operator and the costs which we incur in that role.

296 Where we are able to identify changes in asset base or operational practice which can reduce levels of UAG, we will make this available to stakeholders. To this extent, we will inform and facilitate the debate on where cost-effective changes can be made whilst reflecting that those costs and incentives may ultimately lie with other stakeholders.

Residual Balancing

Overview

297 Our residual balancing activity involves buying and selling over £100m of gas per year on behalf of the industry. We are currently incentivised by a scheme based on performance measures which encourage the daily balancing of supply and demand within each gas day, whilst minimising the impact of any SO actions on market prices.

298 Ofgem's January 2012 document[35] considered the potential for a cost minimisation scheme. Stakeholders did not support a cost minimisation scheme, although one said that a hybrid approach might be possible. We do not consider this approach is appropriate given the nature of the residual balancing activity. We therefore propose an eight year scheme based on performance measures, similar to the current scheme, but with mechanisms to update annual targets on an ex-ante basis to adjust for changing market conditions.

299 Stakeholders have told us they support the current incentive as it has worked well over recent years with a number supporting further tightening of the target, as we have recently been outperforming the incentive.

300 We also propose to sharpen this incentive and increase the value to reflect the value of this activity to our stakeholders. Stakeholders questioned our proposal to double the daily maximum value with a number saying they could not see what value it was bringing to them. This Business Plan details our rationale for our valuation taking account of the value of the gas traded and the service provided on behalf of the industry.

301 We consider that our proposed approach will promote efficiency in the gas market as a whole by ensuring that performance targets reflect those elements of residual balancing which can be forecast and controlled by us. This will provide an incentive scheme that will encourage us to balance supply and demand in an efficient manner, minimising our impact on the market over the RIIO-T1 period.

Background

302 The aim of the current commercial regime is to encourage market participants to achieve a reasonable balance for each balancing period (gas day). If balance is not expected to be achieved, on any given day, the purpose of the SO's Residual Balancing role is to resolve any aggregate forecast imbalance. To achieve this, due to current UNC restrictions, we are currently only able to trade on the On-the-day Commodity Market (OCM).

The value of our residual balancing trades is currently in excess of £100m a year. As the market tends to be long (more supply than demand), there are more sales (by volume and value) than buys over a year.

---

[35] http://www.ofgem.gov.uk/Pages/MoreInformation.aspx?docid=277&refer=Markets/WhlMkts/EffSystemOps/SystOpIncent

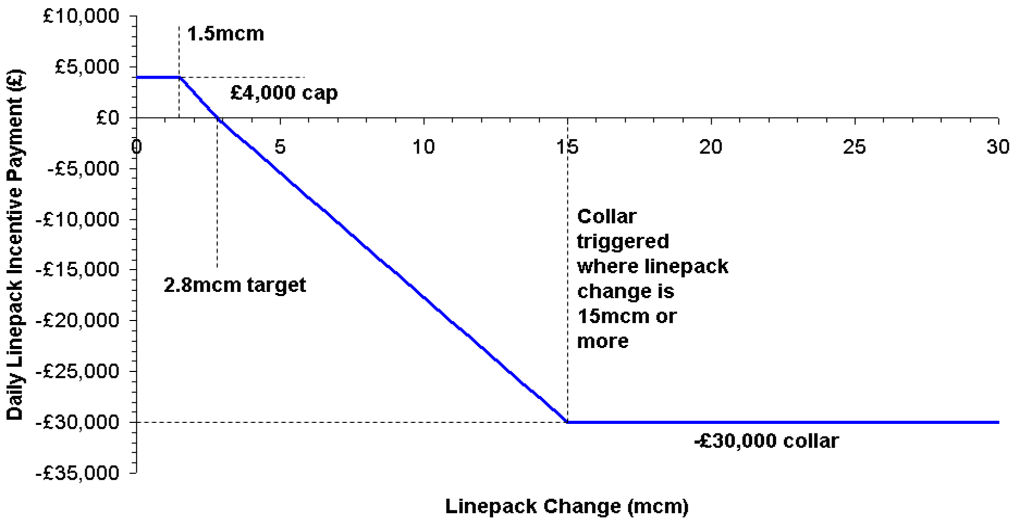
Year	Total traded Buys (£m)	Total traded Sells (£m)	Total value (£m)	Net Revenue (£m)
2008/09	32.2	72.7	104.9	40.5
2009/10	31.5	43.5	75.1	12.0
2010/11	37.6	74.2	111.8	36.6
2011/12	39.1	109.8	148.9	70.7

303 Although we are responsible for the physical balance of the system, the market participants are financially responsible for balancing their portfolio. Any revenues or costs incurred by us through the energy balancing regime are passed through to Shippers via the Balancing Neutrality mechanism as set out in the UNC. The apportionment is based on each shipper's throughput (allocated inputs plus outputs, divided by two).

304 The current Residual Balancing incentive contains two elements comprising of a Price Performance Measure (PPM) and a Linepack Performance Measure (LPM).

305 The LPM incentivises us to minimise any changes between starting and closing NTS linepack over a gas day (i.e. to achieve a reasonable balance between the supply and demand on the gas day), to incentivise resolution of system imbalances on the relevant gas day. The target for 2012/13 is to limit the change in linepack between the start and end of the day to below 2.8mcm as shown below:

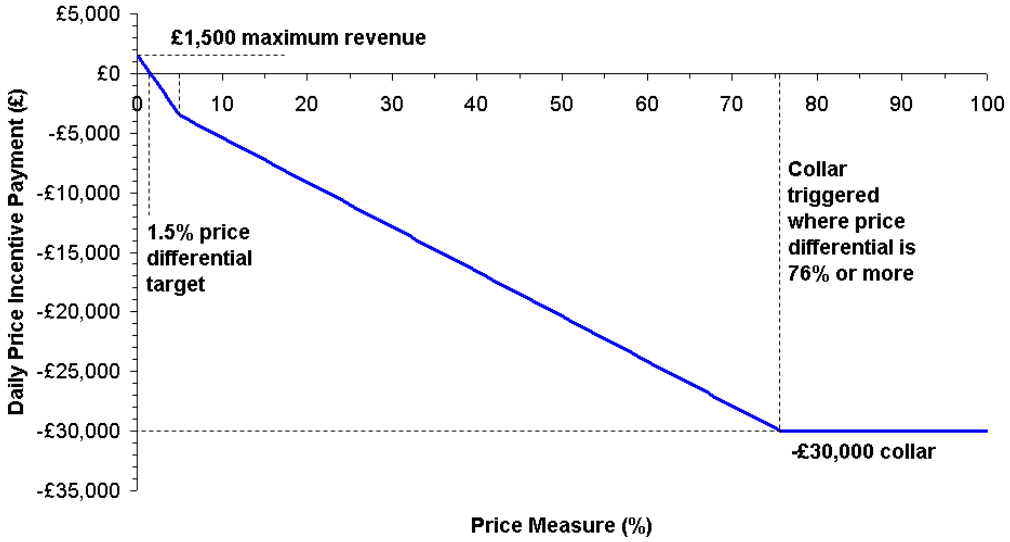
Linepack component of the Residual Balancing Incentive



306 The PPM incentivises us to execute any residual balancing trades at prices within a small range compared to the System Average Price (SAP) for the day. The aim of which is to encourage minimal impact of our balancing trades on the market, particularly important because the price of our balancing trades can set the price paid or received by Shippers for any imbalance. Specifically, the PPM is defined as the

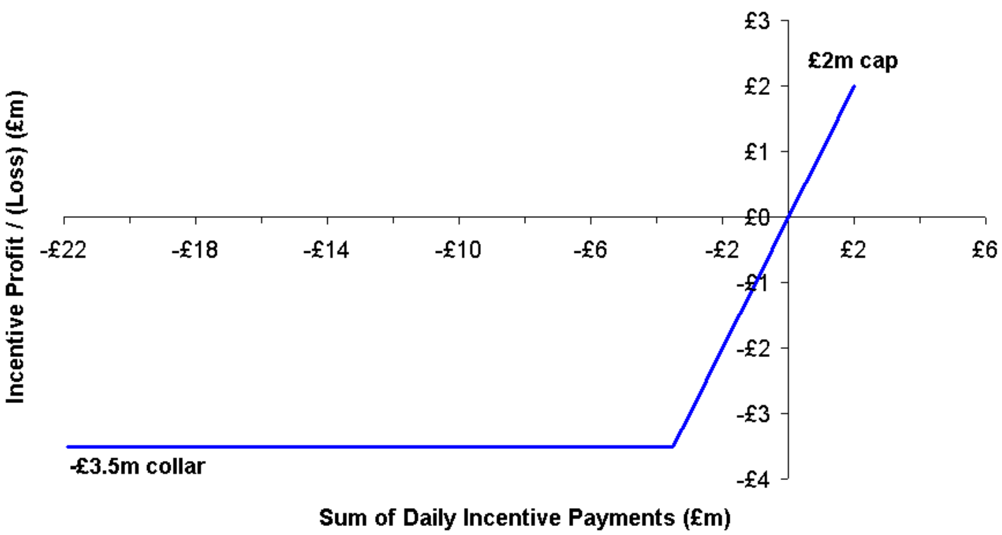
difference between the highest and lowest prices at which we trade on a day divided by SAP. The target for 2012/13 is a price spread of 1.5% of SAP[36] as shown below:

Price component of the Residual Balancing Incentive



307 The daily price and linepack performance is aggregated for the year and subject to a cap of £2m and collar of £3.5m as shown below:

Overall Residual Balancing Incentive



308 The current linepack change target of 2.8mcm was set in 2009. This target was based on user imbalance net of SO balancing actions[37]. Since 2009 the price target has tightened from 5% (2009/10), to 2.5% (2010/11), and to 1.5% (2011/12 and

---

[36] It should be noted that the scheme does not incentivise trading at values close to SAP; alternatively it incentivises trading within a price band which is a proportion of the prevailing SAP price.

[37] 2.8mcm was calculated as a 12 month average of daily linepack change minus net trade volume (positive for buys, negative for sells) for the year to June 2008.

2012/13). Targets and performance in recent years are summarised in the Table below.

Residual Balancing targets and performance in recent years

Incentive Year	Incentive Target (daily)		Performance (average, all days in year)		Aggregate Incentive Performance
	Price	Linepack	PPM	LPM	
2007/08	10%	2.4 mcm	2.63%	2.49 mcm	£1.41m
2008/09	10%	2.4 mcm	2.22%	2.41 mcm	£1.54m
2009/10	5%	2.8 mcm	2.90%	1.97 mcm	£1.63m
2010/11	2.5%	2.8 mcm	1.58%	2.05 mcm	£0.95m
2011/12	1.5%	2.8 mcm	1.57%	2.46 mcm	£0.25m

309 A number of stakeholders commented that we had consistently outperformed the current residual balancing incentive and that it should be tightened to drive further performance improvements. However, another stakeholder supported the retention of existing incentive parameters.

310 The above table shows that since 2009, the price target has tightened to the extent that incentive revenue has significantly reduced and had a negative effect on overall Residual Balancing performance in 2011/12. The daily target level in p/th (obtained by multiplying SAP by the target) has reduced below 1p/th, to close to the size of the default cashout differential, currently 0.77p/th[38]. Hence, it has become more difficult for us to set a cashout price in order to balance the market, while staying within the price target. This significantly limits our opportunity to achieve the target. We address this in our proposals below by linking the targets and value of the scheme to prevailing market conditions during the RIIO-T1 period.

Developments expected over RIIO-T1 period and TO plan Interactions

311 The requirement for residual balancing actions is driven by the expected difference between supply and demand on the gas day. The following changes are expected to impact on the volatility and forecastability of supply and demand patterns on the NTS over the RIIO-T1 period:

(a) Increasing levels of LNG and interconnector imports replacing indigenous supplies which have the potential to be more volatile due to their responsiveness to global prices;

(b) On the demand side, wind intermittency will increase within-day and inter-day demand variation, driving increased requirements for within-day actions, and may increase the end of day market imbalance and therefore the need for balancing actions;

[38] The current default cashout differential price (applicable for gas year commencing 1 October 2011) was set in accordance with the methodology introduced by the implementation of UNC Modification 0333A (implemented on 1 October 2011).

(c) Storage facilities with high injection and withdrawal rates will help balance these increasingly volatile demand patterns. The speed and flexibility associated with such facilities means that storage will not always respond to price signals in a predictable way;

(d) The development and implementation of European network codes, required by the EU Energy Infrastructure 3rd Package that will govern our residual balancing role, will impact on our residual balancing activities during the RIIO-T1 period. The impact of these changes is unknown, but is expected to increase rather than decrease the uncertainty around end of day market imbalance. For example, Operational Balancing Agreements could lead to unforeseen increases or decreases in linepack via interconnectors.

Proposed Approach

312 A performance measure scheme, based on daily linepack change and daily price spread, similar to the current design, represents a proxy for a market cost minimisation outcome as it incentivises us to make minimal intervention in the market. As such this minimises the impact on the normal operation of the market enabling it to achieve balance at least cost. Such a scheme therefore focuses on encouraging us to resolve any imbalance, whilst not significantly impacting the market, not just in terms of the current gas day but to minimise the risk of our Residual actions impacting further along the curve.

313 During our stakeholder engagement we have requested views regarding the structure of the residual balancing incentive including whether a cost minimisation incentive or the current form of residual balancing incentive would be more appropriate. In summary, responses from the industry have been mixed. In March, three out of six responses to Ofgem's January document viewed the current performance measures approach as appropriate, as they believed they were working well. A cost incentive was supported by two respondents, and a further respondent felt the objective of a cost minimisation incentive was unclear, with a need to protect against trading away from market price. Another suggested it would be unlikely to be suited to an eight year scheme.

314 Following our April 2012 Stakeholder Consultation three of the four responses supported the continuation of a scheme which is similar to the current incentives in principle. Concerns were raised that a cost minimisation incentive will create distortions in the OCM by encouraging the taking of actions that are not close to the market price and therefore would have an undue effect on cash out[39] prices. All respondents questioned the robustness of the current price and linepack targets given the uncertainty over the RIIO-T1 period.

“*We believe that the existing incentive regime has proven effective and created stability in the market, and as such, should remain*”
SSE's response to National Grid's consultation, May 2012

315 One stakeholder did say they supported the current incentive being improved by combining it with a cost minimisation incentive so that we were incentivised to limit

[39] 'Cashout' is the value at which shippers daily imbalances are reconciled. 'Short' shippers are charged additional amounts for their negative imbalance (deficit) and 'long' shippers are refunded amounts for their positive imbalance (surplus).

our balancing actions but made maximum use of linepack in the most cost effective manner. They stressed they did not support the introduction of a flexibility service.

316 In line with stakeholder feedback we are therefore proposing a similar scheme structure to the existing incentive, with two components based on daily linepack change and daily price spread, which are measured for each gas day. Under the current performance measures, we are incentivised to:

(a) Allow shippers to resolve their own imbalances when possible; and

(b) When buying and selling is necessary, minimise the price spreads, and therefore take efficient trading actions.

317 We propose that the scheme will be a series of annual incentives within an 8 year framework, with a midpoint review to ensure that the scheme is operating as intended. For each year, the value and targets for both linepack and price will be fixed and set ex ante based on market outturns for the previous year. The Table below summarises our proposals.

Summary of Proposed Residual Balancing Scheme

Scheme Aspect	Proposal
Performance period	Day in incentive year
Price Performance measure (to minimize impact of SO trades on market)	Target: Average daily market price range in previous year x 40% Measure: Price Spread of SO trades.
Linepack Performance measure (to maintain 'polluter pays' principle)	Target: Previous year average shipper imbalance Measure: Change in linepack over the gas day.
Length	Annual Scheme within 8 year framework with a planned midpoint review, if necessary.
Value per day	+£9k[40] to -£60k
Value per year	+£3.3m[41] to -£3.5m

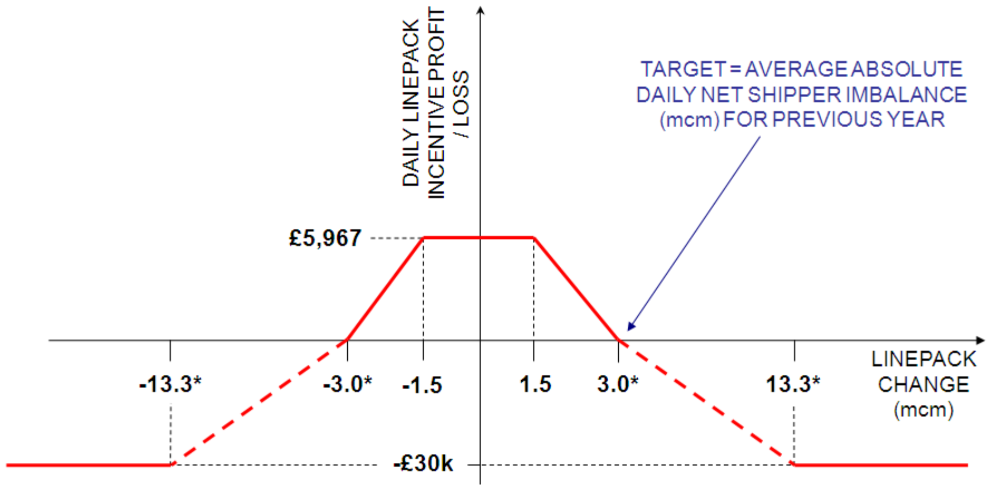
318 The combination of the Linepack and Price schemes effectively incentivise us to optimise our trading activities to minimise our impact on the market whilst seeking an appropriate allocation of costs as described in more detail below.

Linepack performance incentive

319 As now, the linepack performance measure aims to maintain the incentive to balance on the day and therefore costs to be targeted to those that are out of balance (the 'polluter pays' principle). This is achieved by ensuring that those shippers out of balance incur the appropriate imbalance charges at the relevant cashout price (set by the Residual Balancer if such trading was necessary).

Linepack Incentive Structure

[40] Estimate based upon 2011/12 data.
[41] Estimate based upon 2011/12 data.



320 The above is an illustration of the proposed linepack performance scheme. As described further below, the starred values have been calculated using data from the incentive year 2011/12. For this period, average absolute net shipper imbalance was 3.0mcm, and this value is shown as the target.

Performance Measure

321 We propose a daily scheme, as now, with performance measured for each gas day to determine a daily incentive payment. The daily performance measure (LPM) is the absolute daily linepack change, in mcm.

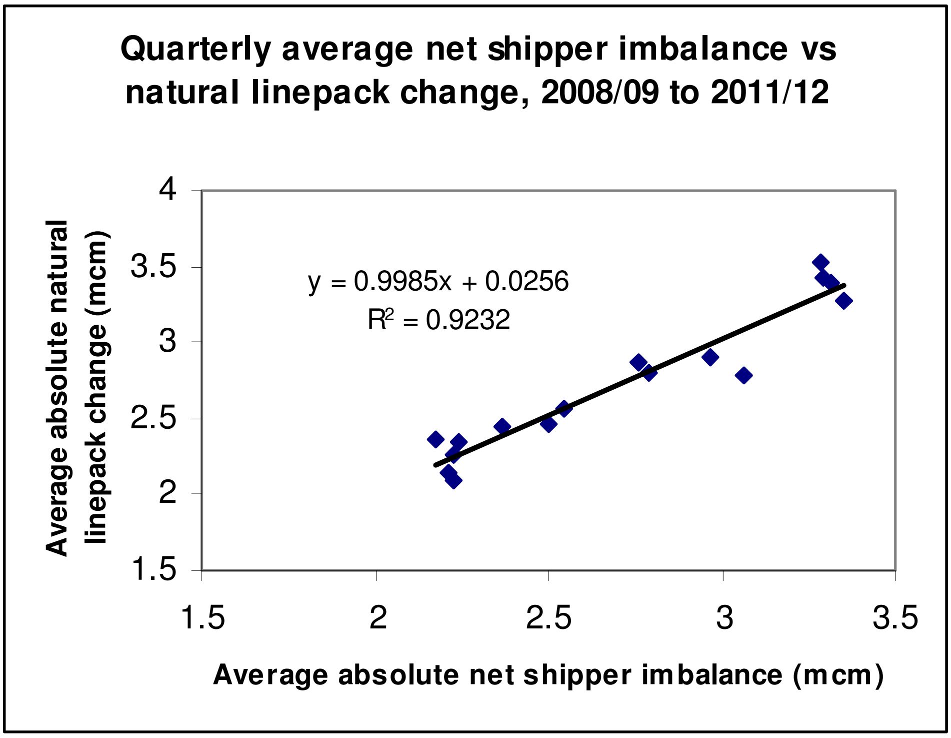
Performance Target

322 The Performance Target sets the commercial imbalance target difference between opening and closing linepack on a gas day. We propose to maintain the current structure where linepack changes of less than 1.5mcm from target are rewarded with a fixed incentive payment. A linepack change of more than 1.5mcm would reduce the incentive payment.

323 The level of linepack change between the start and end of the gas day is inherently linked to the level of shipper imbalance. Therefore any target for linepack should be influenced by this level of imbalance. The relationship between net shipper imbalance and linepack is much stronger if the volume traded by the SO as residual balancer is netted off the linepack change[42]. This is illustrated in the figure below:

[42] The correlation has an R^2 value of 0.9232, whereas the correlation without netting off SO Residual Balancing trades has an R^2 0.6332.

Net shipper imbalance and natural linepack change



324 Whilst some stakeholders questioned the need to move away from a fixed target we have concluded on the basis of the above analysis that in order to ensure that the Linepack Performance Target remains robust within the RIIO-T1 period, it is appropriate that the target to be applied for an Incentive Year is determined in accordance with the following formula:

$$\text{Linepack Performance Target} = \frac{\text{Sum for all days in the previous Incentive Year}\left(\text{Absolute Daily Aggregate User Imbalance (mcm)}\right)}{\text{Number of Days in Previous incentive Year}}$$

325 We propose that if the target for a given year is relatively low, and below 2mcm, the fixed payment threshold is reduced below the 1.5mcm level, and set at 0.5mcm less than the target. This will ensure that in the event of a low target, there is a continuous incentive to reduce the daily linepack change to below the target value, with no step changes in profit/loss. In particular, we propose:

(a) If the linepack performance target is greater than, or equal to 2mcm, then the linepack fixed payment threshold is equal to 1.5mcm;

(b) If the linepack performance target is greater than, or equal to 0.5mcm but less than 2mcm, then the linepack fixed payment threshold is equal to the target minus 0.5mcm; or

(c) Otherwise the linepack fixed payment threshold is equal to 0mcm.

326 A linepack change greater than target would result in an incentive loss, increasing to a maximum loss for linepack changes greater or equal to a threshold. We suggest that the current collar of -£30k is retained.

Linepack Performance Incentive – Exceptional Event Adjuster

327 During our stakeholder engagement process, a stakeholder asked about the appropriateness of incentivising a closing linepack volume position proximate to the opening linepack volume where the opening position itself has been influenced by an exceptional event (e.g. significant supply loss) on the previous gas day.

328 We agree that in such an event such a case, incentivisation of achieving a more typical linepack volume may be more appropriate as opposed to a position that has been influenced by an exceptional event.

329 In response to this feedback, we have undertaken analysis to identify the extent of daily imbalance experienced in the last four complete incentive years in order to identify an appropriate linepack change threshold (mcm). This is summarised in the following Table:

Absolute Linepack Change Frequency

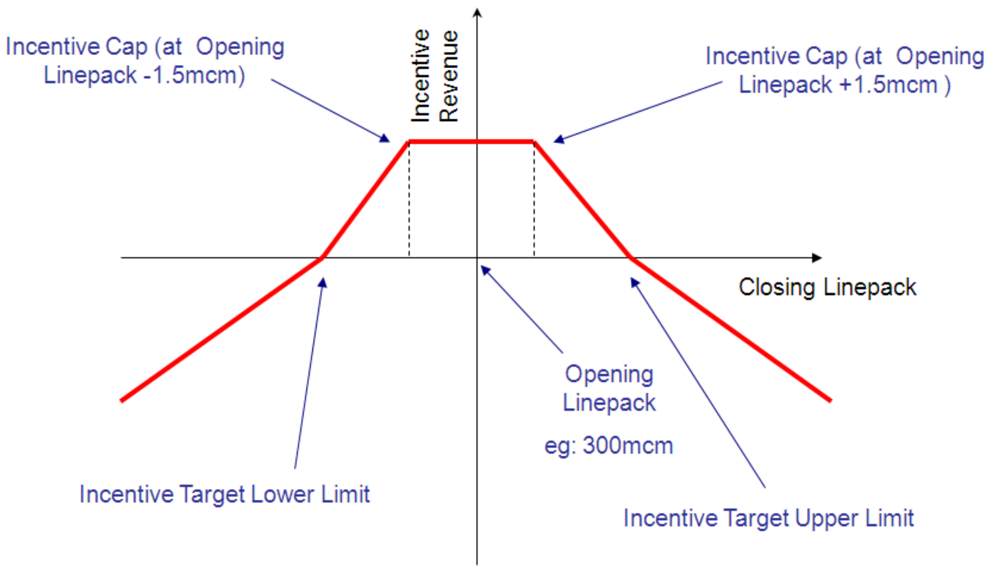
Absolute Imbalance Range (mcm)	Apr-08	Apr-09	Apr-10	Apr-11	All	8mcm Split
0 to <2	53.97%	57.81%	61.64%	50.55%	55.99%	98.56%
2 to <4	28.77%	30.96%	26.30%	33.06%	29.77%	
4 to <6	10.68%	8.49%	8.77%	8.47%	9.10%	
6 to <8	4.93%	1.92%	2.19%	5.74%	3.70%	
8 to <10	1.10%	0.27%	0.82%	1.64%	0.96%	1.44%
10 to <12	0.55%	0.55%	0.00%	0.00%	0.27%	
12 to <14	0.00%	0.00%	0.27%	0.27%	0.14%	
14 to <16	0.00%	0.00%	0.00%	0.27%	0.07%	
All	**100.00%**	**100.00%**	**100.00%**	**100.00%**	**100.00%**	**100.00%**

330 We have concluded that an appropriate indicator of an exceptional event is a daily linepack change (between opening and closing linepack) of 8mcm or greater. Based upon historic analysis this is only likely to occur on about 5 days within the average year.

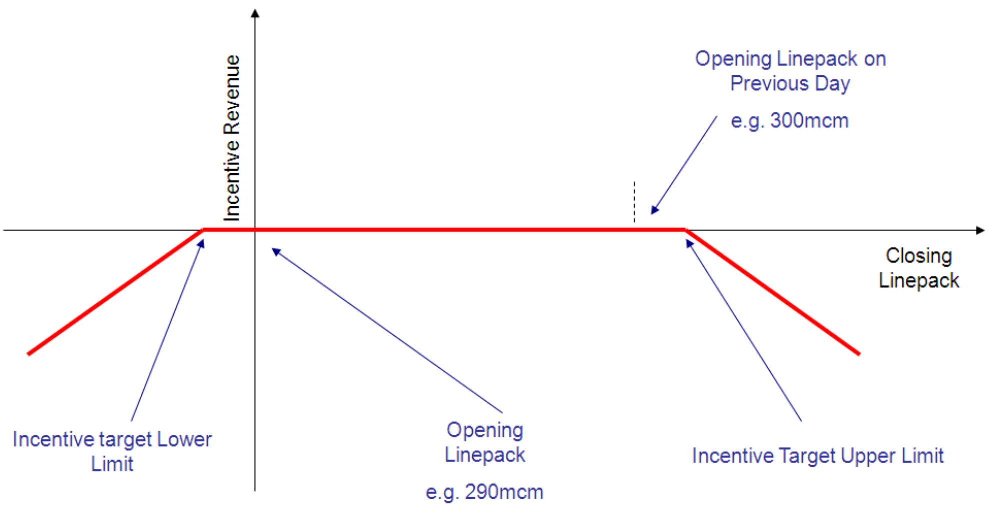
331 On this basis, and in response to the feedback received, we propose that the scheme should also include an adjustment mechanism to deal with exceptional events which influence opening linepack. We propose this adjustment mechanism applies where the closing linepack volume on Gas Day ‘D’ is 8mcm or more higher or lower than the opening linepack volume on Gas Day ‘D’ in which case the performance target would comprise a wider range than on non-exceptional days. The formula for determination of the performance target in this case is detailed within Appendix 5.

332 We propose that in an exceptional event the scheme will be downside only on such days. The following diagrams compare the incentive scheme on a ‘normal’ day and an ‘exceptional event’ day:

Residual balancing Incentive – Normal Day



Residual Balancing – Exceptional Event Day e.g. supply loss



333 The proposed Linepack Performance measure with the exceptional event adjuster represents our preferred approach as it removes the risk of windfall loss as a consequence of events likely to be outside our control.

Price performance Incentive

334 The objective of the price performance incentive is to incentivise minimal market intervention (ideally no residual balancing actions) by encouraging a minimal price spread of our trading actions. Stakeholders support the view that our interventions in the market should be kept to a minimum and concur that the current form of Price Performance Measure is an appropriate way to achieve this.

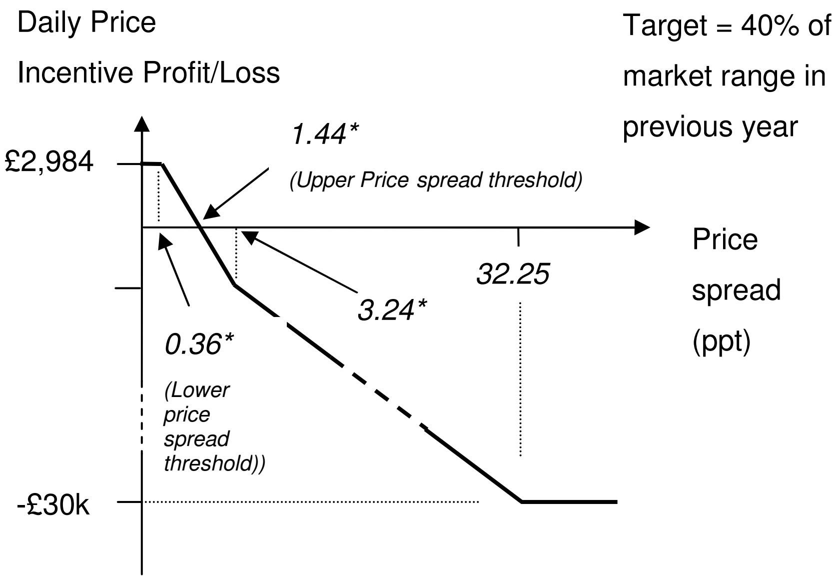
"the SO should continue to be financially incentivised such that any actions it takes on the day commodity market (OCM), are as close to the market price as possible"
SSE's response to National Grid's consultation, May 2012

“”

“NG should continue to be incentivised to trade close to market prices, to minimise its impact on the market.”
Energy UK response to National Grid’s consultation, May 2012

335 We propose a daily scheme, as now, but with measured daily price spread of Residual Balancing actions in pence per therm (i.e. maximum price minus minimum price of any residual balancing trades on the day). If no trades are executed, the price spread is taken as zero, as now.

Price Incentive Structure



336 The above diagram is an illustration of the proposed Price Performance Scheme. The starred values have been calculated using data for the 2011/12 incentive year.

Price Performance Measure

337 We propose that our performance is measured by the absolute price spread (in pence per therm) rather than converted to a percentage of SAP as now. The price spread will be reflective of recent market price volatility conditions experienced rather than a fixed percentage of SAP target.

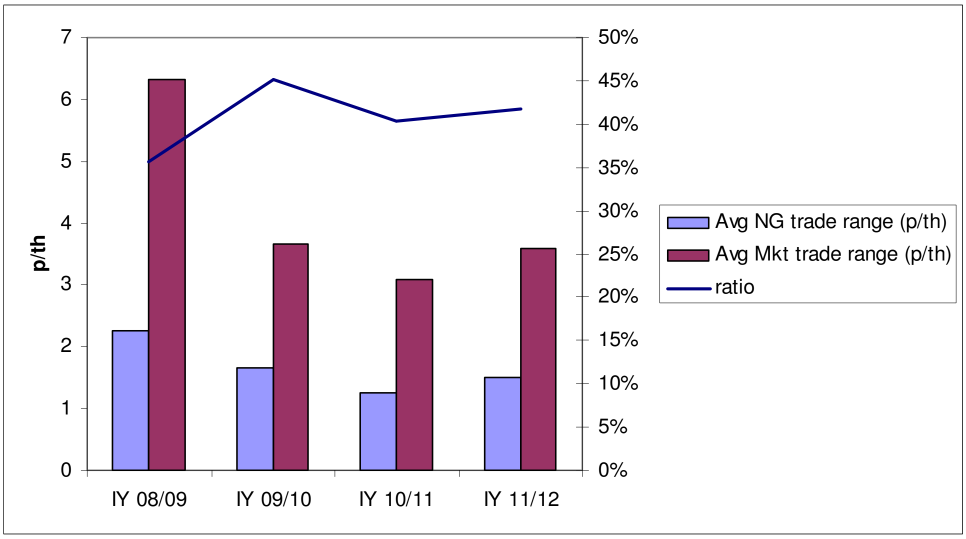
338 The balancing conditions on any given day are not necessarily directly linked to the size of SAP as the ability to balance is driven more by market volatility. For example a 2% of SAP price measure on a 50p/th day would give a performance target of trading within 1p/th. The ability to drive a balance while staying within this tolerance is likely to be very different dependant on whether the overall market price spread is 2p/th on that day or 8p/th. We propose to assess our performance on the basis of the price spread of our trades which are more within our control.

339 The default cashout differential (beyond which our trades will set cashout price) is defined as a fixed value in p/th, rather than a percentage of SAP. It is therefore appropriate for the price spread target in the Residual Balancing incentive to also be in p/th, and be no lower than the level of that differential in order to allow the residual balancer to set an appropriate incentive for the market to self-balance.

Price Performance Target

340 Going forward, it is important to ensure that the target is robust for the long term and adjusts with market conditions, as need to trade, the price and price spread of our trades are heavily influenced by the market. The current target is not appropriate for a longer scheme because it is fixed rather than adjusting for market conditions. We have therefore examined correlations between the average price spread of all trades on the OCM and the average price spread of our balancing trades for the last four years in order to determine an appropriate method for setting an annual Price Performance Target.

Price spreads and market trade ranges



341 The graph shows the average price spread of all trades on the OCM for all days, which therefore includes the effect of our Residual Balancing actions. In 2010/11, for example, the market price range for all trades averaged 3.0p/th.

342 Also evident is a downward trend in the market price spread however the price spread increased again for 2011/12. We do not know if this will continue but we have no reason to expect a decrease given the increased levels of supply and demand volatility. For the last three years we achieved a price spread of between 40-45% of the market price range.

343 We therefore propose an annual target (break-even point) for the daily price spread based on 40% of the average market price range from the previous year (i.e. the price range allowed for 2013/14 is set based upon the market trading range seen in 2012/13). Hence, if we trade with similar price spreads relative to the market as now, the incentive payment would be zero.

344 Any target however should be no lower than the prevailing default cashout differential, to ensure the residual balancing mechanism is able to provide sharper balancing signals than cashout alone.

345 Accordingly, we propose that the Price Performance Target is determined each year as follows:

Price Performance Target = The Greater of (Daily Cashout Differential *and* 40% of the average Daily Market trade range in Previous Incentive Year)

346 For 2011/12, the average market price range was 3.6p/th, which would give a target value of 40% of 3.6p/th = 1.44p/th.

347 The proposed performance target takes into account market volatility to enable it to reflect market conditions over a longer period through the annual update.

Price performance – Incentive Scheme

348 We propose a price spread threshold equal to 10% of the previous year's market spread. This reflects the possibility that there may be an increase to the number of actions going forwards and trading within a small price range should not be penalised. Hence, the maximum reward under the incentive would occur with a daily price spread of less than or equal to 10% of the market spread.

349 A price spread of more than 10% of the previous year's market spread would reduce the Incentive Payment, decreasing to zero at the target (i.e. 40% of the previous incentive year's average price spread).

350 A price spread greater than target would result in a loss under the incentive scheme. We propose to use two gradients in the scheme. Firstly, price spreads between 10% and 90% of previous year's market value would be valued using the same gradient. Secondly, price spreads greater than the 90% level would incur incentive penalties increasing to a maximum. We propose that the maximum penalty be capped at £30k, as now, and the threshold is equal to the maximum market movement seen in the last 2 years, 32.25p/th, which would be fixed for the duration of the scheme. The last two years is an appropriate measure as it covers a period where the current incentive was set and encompasses both a cold and mild winter.

351 The strength of the incentive (i.e. the gradients of the scheme) will increase or decrease from year to year depending on the prevailing market conditions, in particular shipper imbalances, market price range and default cashout differential. The proposed scheme will recognise the resolution of imbalances whilst trading within a tight price spread, acknowledging that there may be need for us to take some additional actions with the uncertainty created from operating in a changing environment.

Length and Uncertainty Mechanisms

352 We are proposing that the incentive scheme framework is set for 8 years in line with the RIIO-T1 period, but the targets adjusted annually in accordance with the principles detailed above. In addition, we propose a midpoint review at 4 years, to review whether the scheme is delivering the desired outcome and the relationships between price spreads remain valid. This would ensure that we have an appropriate incentive scheme that does not drive undesirable impacts on shipper imbalance positions, price volatility or result in windfall profits or loss. The proposed *annual* ex-ante calculation should ensure that the Residual Balancing incentive parameters remain appropriate throughout the duration of the scheme.

353 At this stage it is difficult to build uncertainty mechanisms into the incentive for factors such as future regime change driven by European Union directives until detailed impacts on the prevailing incentive schemes are known. Therefore we propose that this would be covered by the regulatory and legislative framework uncertainty mechanism under our RIIO-T1 proposals to enable a review of the incentive, if this uncertainty mechanism was triggered. Similarly, there maybe further unforeseen changes that could have a similar impact that we would expect to be covered by this

uncertainty mechanism to ensure that the potential for windfall losses and gains is minimised.

Incentive Value

The value of good performance – our recommended approach

354 Our residual balancing role currently involves buying and selling gas worth over £100m a year. In the last two incentive years, the absolute value of our Residual Balancing Trades was £112m in 2010/11 and £149m in 2011/12. Although the current incentive has a cap of £2m and a collar of -£3.5m, recent performance shows that the realistic level of potential profit or loss on the Residual Balancing incentive is currently around +/- £0.5m, a fraction of the value of the gas traded and potential impact of our actions. We consider that good performance in Residual Balancing is currently undervalued.

355 For the current and previous two incentive years, the reward for best performance for linepack change and price spread is £4,000/day and £1,500/day respectively. We believe these represent very low levels of value for optimising performance in an activity conducted on behalf of the market with a typical absolute cost of in excess of £100m per annum. The current levels are not based on any particular method of valuing the balancing task, but are more arbitrary and have evolved from the parameters of earlier schemes.

356 At present we are proposing to value performance on the incentive using the default cashout differential, currently 0.77p/th[43] for the year from 1 October 2011, which is a proxy for the value of Linepack. We propose to update the calculation of this value (currently a daily value of £8,951) using the prevailing default cashout differential at the commencement of each incentive year.

Combined value of linepack and price components – an option

357 There are of course a number of ways to value the residual balancing role. In this approach we identify the value of our activity to the market on the basis of:

(a) Our estimate of shipper imbalance if we had taken no actions is 4.6mcm/day on average

(b) The balancing tolerance is 1.5mcm either side of the balance point as we do not aim to perfectly balance, (as this is potentially not efficient and may not operationally necessary) in line with the current incentive

(c) We estimate that, on average, the value of our residual balancing activity is the value of reducing a shipper imbalance from around 4.6mcm/d to below 1.5mcm/d, therefore a 3.1 mcm movement; and

(d) If the change is valued at the default cashout differential price (currently 0.77p/th) this is equivalent to a daily value of £8,951[44]

[43] This is the current value as a consequence of the implementation of UNC Modification 0333A in 2011. This was raised pursuant to the requirements of Special Condition C27 of National Grid's Licence.
[44] Using a conversion factor of 1mcm = 375,000th i.e. (3.1mcm * 375,000) * 0.77p/th = £8,951

358 Stakeholders told us at our workshop and through our consultation that they could see little value to them in us doubling the daily maximum value.

“”

“We fail to see what benefits this would bring to Shippers (who fund the incentive) and do not believe the case for change has been made.”
EON’s response to National Grid’s consultation, May 2012

359 This approach provides a scheme that values efficient balancing based on the prevailing market conditions, rather than using arbitrary levels. The value is based on an estimate of the volume of work (shipper imbalance net of SO balancing actions), and a market price for this volume (the default cashout differential). The value of the scheme will therefore vary from year to year and reflect changes in the market.

360 We propose that this daily value is split between the linepack and price components. As now, a greater value of the linepack component compared to the price component would encourage a greater emphasis on the principle of “polluter pays” rather than “minimal effect on market”. We propose to split the value as two thirds on linepack, one third on price. Hence using current values, the linepack incentive would have a maximum daily value of £5,967, and the price incentive would have a maximum daily value of £2,984.

Other valuation options

361 A further alternative approach is as follows. The financial value of the incentive, relative to the value of the gas traded in the Residual Balancing activity has significantly declined over the years. The incentive set for the five year price control commencing 2002, when gas prices were approximately 20p/th, had a maximum of £10,000 daily value for best performance (£5,000 each for linepack and price), with an annual cap and collar of £3.5m and -£3.5m respectively. Gas prices are currently around 60p/th, and residual balancing trades have an annual value of £100m to £150m, but best performance is currently valued at only £5.5k/day.

362 An alternative approach to value could therefore be to utilise a “percentage of turnover”. In this option the maximum daily value (of linepack and price components combined) would be set as a percentage of the average value of gas bought and sold on a day. For incentive year 2011/12, the value of residual trades was £149m, equivalent to £407k/day.

Delivering Benefits for the Consumer

363 A performance measure scheme will be beneficial for consumers because it will continue to encourage us to balance supply and demand in an efficient manner, minimising our impact on the market, and promoting efficiency in the gas market as a whole. The proposed linepack incentive will maintain the incentive to ensure that the ‘polluter pays’ with costs appropriately allocated between Users therefore promoting competition. In contrast, a cost minimisation scheme (as described below) may have the effect of increasing gas prices and may potentially impact on price volatility.

364 The adjustment of targets in line with prevailing market balancing conditions will mean we have appropriate challenging efficiency targets for the duration of the scheme, taking into account the unknown future market conditions. An appropriately valued residual balancing scheme will enable us to prioritise this significant activity.

365 Our proposal is in line with the principles described by Ofgem in their January document. In particular, we are proposing an eight year scheme, financially

incentivising the key output measures, with rules for adjusting the targets for factors outside of our control during the period. We are not proposing a cost minimisation incentive scheme (see below), as we believe this may not lead to a better outcome for the market as a whole.

Gas Procurement Incentive Consistency

366 Both the Residual Balancing function and the Shrinkage provider, at a high level, buy gas to resolve a position in the market and questions have been raised as to why the incentive treatment differs. However, Shrinkage and Residual Balancing are fundamentally different activities as shown below and therefore it is appropriate that each function is subject to different regulatory approaches.

Key features of the Shrinkage Provider and Residual Balancer Role

	Shrinkage Provider	Residual Balancer
Typical trading behaviour	Buy	Buy and sell
Objective	To achieve fixed volume at lowest cost	To signal market to balance
Procurement Timescales	Any point during Y-1 to D	Principally on D
Markets	OTC[45], OCM, ICE[46]	OCM only
Cashout exposure	Yes	No
Ability to Set System Marginal Price	No	Yes

367 For Shrinkage, we act as a Shipper (“Shrinkage Provider”) that procures gas in the same way as other shippers in the market. Procurement is carried out over a longer timeframe and based upon a long term physical requirement forecast; the trades are executed up to two years in advance of delivery. The Shrinkage provider has access to a number of markets such as the over the counter (‘OTC’) brokered markets, and the OCM, These markets make up the majority of the traded gas market. Additionally the Shrinkage Provider is exposed to cashout as other shippers are.

368 However, in our role as Residual Balancer, we act as a balancer across all shippers, where the majority of actions are taken on the actual gas day and aimed at resolving any total system imbalance, which itself is a function of all shippers’ imbalances. We do not have our own distinct portfolio to balance. The residual balancer is a role defined in UNC and we are restricted where we can take action, with the only platform we can utilise for residual balancing purposes is the OCM. Within this market we are unique as we are the only market participant who can directly set a cashout price with a trade.

369 When the residual balancer decides to buy or sell during the day we may cause a change in shipper imbalance at the end of the day by setting cashout prices or

[45] Over the Counter (brokered) market
[46] Intercontinental Exchange

influencing the market by signalling that the system is short or long with our trade. This helps maintain a system balance, as encouraged by the Linepack element of the Residual Balancing incentive. When taking action the decision is based upon forecast end of day imbalance and trading occurs in a live market.

Alternative Option: Cost Minimisation

370 Ofgem asked whether a cost minimisation incentive approach would be appropriate for Residual Balancing in its January 2012 consultation. The following Table summarises our key conclusions in respect of a costs minimisation scheme compared to proposed Linepack and Price schemes:

Residual Balancing Scheme Comparison

<table>
<tr><th></th><th>Cost Incentive</th><th>Linepack Incentive</th><th>Price Incentive</th></tr>
<tr><td>Minimising Cost of Balancing Function</td><td>SO incentivised to:
Minimise buy costs; and
Maximise sale revenues.</td><td colspan="2">Combination effectively incentivises cost minimisation over the longer term by incentivising the SO to influence the market to address imbalance within the day.</td></tr>
<tr><td>Unintended Consequences</td><td>Potential to increase gas prices.
Risk of windfall profit or loss due to difficulties in setting an appropriate volume target (see below).</td><td>None</td><td>None</td></tr>
<tr><td>Setting a Target</td><td>We are unable to identify a suitable methodology to determine a target volume.</td><td>Proposed methodology to base target upon prevailing extent of Users' imbalance</td><td>Proposed methodology to base target upon recent market price spread.</td></tr>
</table>

371 Stakeholder views in respect of a Residual Balancing cost incentive expressed during our stakeholder consultation are reflected below:

"*We do not support the proposal to introduce an incentive based on the total cost of the SO's balancing actions as we are concerned that it will create distortions in the OCM by encouraging the taking of actions that are not close to the market price and therefore would have an undue effect on cash out prices. We believe that the existing incentive regime has proven effective and created stability in the market, and as such, should remain. However, we note that NGG has consistently outperformed its residual balancing incentive in each of the last 4 years and as such the incentive measures should be further tightened"*
SSE response to April 2012 SO Consultation

"we also recognise that a pure cost minimisation scheme, as occurs in electricity, may not be appropriate for gas due to the differing characteristics of the products and the markets. We therefore support the maintenance of the current Residual Balancing incentive, but believe that this could be improved if this were combined with a cost minimisation incentive so that National Grid were incentivised to limit its balancing actions but make the maximum use of linepack in the most cost efficient

manner. For the avoidance of doubt we do not support the introduction of a flexibility service."
EDF response to April 2012 SO Consultation

"We do not support a cost minimisation incentive as we do not see a strong need to change the incentive. The incentive should be structured appropriately to avoid encouraging NG actions in the market, which risk creating distortions on the OCM."
Energy UK response to April 2012 SO Consultation

372 A 'Net' cost scheme for Residual Balancing could be implemented; however such a change would be likely to encourage changes in behaviour that could result in raising gas prices for the market as a whole and have a direct cost impact for the consumer.

373 Under a net cost scheme we could pursue an asymmetric trading strategy for energy balancing. This would involve buying through the stack to set 'SMP Buy' prices when the opportunity arose, and selling a large volume over a long period at prices close to SAP when possible. In fact, a theoretical incentive would exist to trade beyond requirements - for example additional buys could create linepack that is sold on subsequent days. This is not aligned to our wider efficient and economic obligations.

374 We are also concerned that we may not be able to identify a robust method for determination of an appropriate methodology to identify a volume benchmark in order to derive a suitable target cost. Further details of our conclusions in respect of a cost minimisation incentive for Residual Balancing are detailed in Appendix 6.

Demand Forecasting

Overview

375 We publish national gas demand forecasts over a range of timescales to assist the industry in making efficient decisions in balancing its supply and demand positions. The accuracy of the gas demand forecast published day-ahead at 13:00[47] is currently incentivised. For 2012/13, the incentive target is a forecast error of 2.75% adjusted for the increase in short-cycle storage injectability.

376 Since 2006, the incentive has driven down the target error from 4% to 2.75%. Whilst the incentive has driven us to provide more accurate forecasts, the increasing volatility and unpredictability of demand over the RIIO-T1 period will undermine the effectiveness of a fixed measure.

377 Stakeholders have told us the 13:00 hrs day ahead (D-1) demand forecast is still the most important forecast for them. A number also said an improved Non-Daily Metered (NDM) forecast would be of value.

378 We are proposing an annual financial incentive scheme with an 8 year framework for the current incentivised forecast at 13:00 D-1 and to extend the incentive to include forecasts for 5 days ahead (D-5) to two days ahead (D-2). In addition, following the stakeholder feedback, we are also proposing to develop a day-ahead NDM demand forecast.

379 We propose that the forecast performance measure and targets should be measured as an absolute mcm value rather than as a percentage of daily demand to ensure that the scale of demand does not unduly impact on performance.

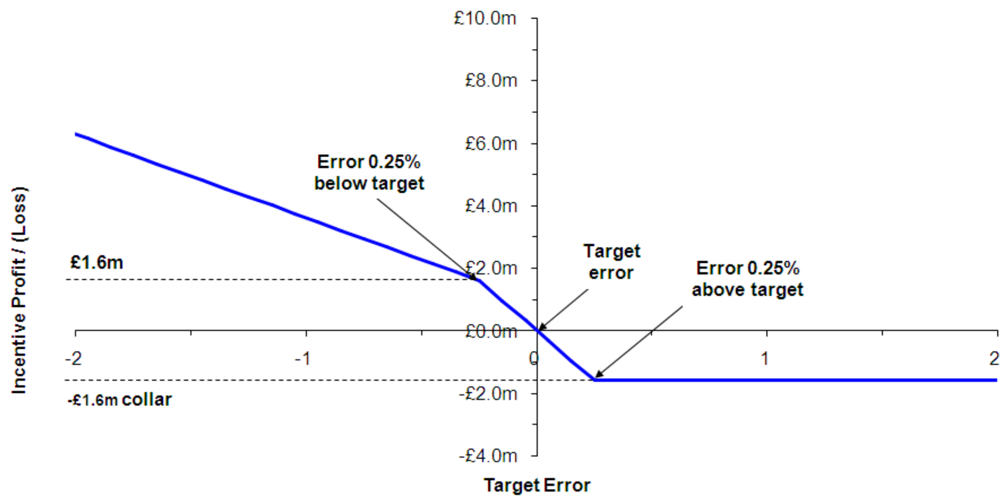
380 To remain reflective of the forecasting environment and ensure we remain appropriately incentivised to improve performance, the target should adjust for changes in the level of demand volatility to align the incentive with the challenge of forecasting accurately on a more volatile environment.

Background

381 The purpose of the current demand forecasting scheme is to incentivise improvements in the accuracy of the 13:00 day ahead (D-1) demand forecast. For 2012/13, the accuracy target is a 2.75% forecast error. The demand forecast error is calculated as the sum of each day's absolute error divided by the sum of each day's actual demand over a one year time period.

Demand Forecasting Incentive for Incentive Year 2012/13

[47] This forecast is published in order to comply with the requirement under UNC Transportation Principal Document section H5.2.3. This requires us to publish a forecast of demand for the Total System by 14:00 on the day preceding the Gas Day



382 To take account of the unpredictability of demand from short-cycle storage sites, the 2.75% target is increased in proportion to the additional injection capability at short-cycle storage in 2012/13 compared to a baseline value from 2011 (19.3mcm/day). This adjustment applies only for new injection capability where we have received notification that it will come on line during 2012/13.

383 The adjustment for short-cycle storage has been capped to an additional 0.35% (an additional 35mcm/day of additional injection capability at short-cycle storage in 2012/13). Accordingly, if further storage capability is connected to the NTS, the maximum demand forecasting target error for 2012/13 is 3.1%.

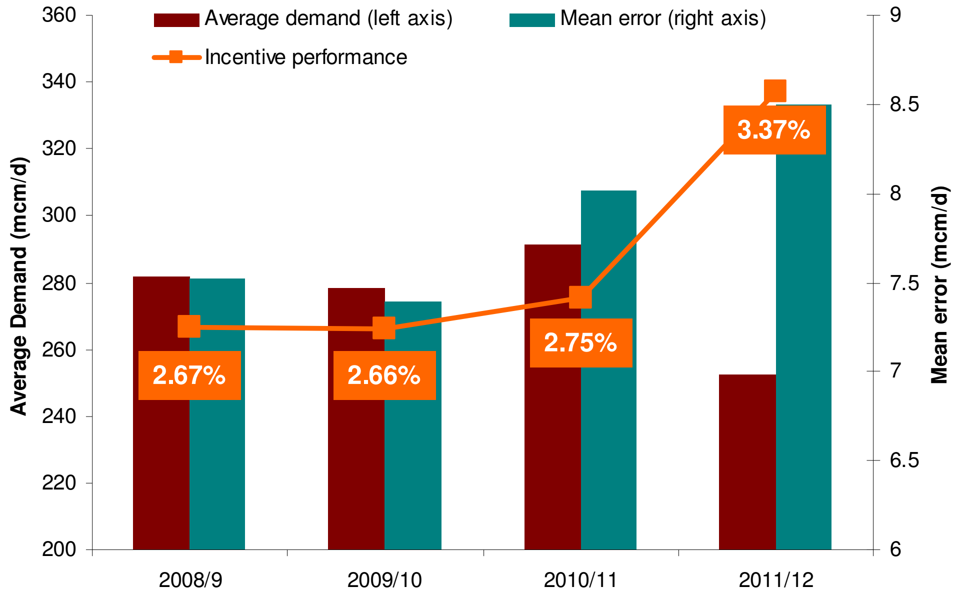
384 Our performance has been relatively consistent between 2008/09 and 2010/11 before significantly deteriorating in 2011/12 (partly driven by significantly lower average demand during the year). This reflects the more challenging forecasting environment across this period, including an increase in demand volatility.

Demand Forecasting Incentive Performance

Incentive year	Incentive target	Forecast error	Incentive profit (loss)
2008/09	3.5%	2.66%	£3.1m
2009/10	3.0%	2.67%	£2.1m
2010/11	2.85%	2.75%	£1.1m
2011/12	2.75%	3.37%	(£1.6m)

385 The current incentive measures forecasting accuracy as a proportion of demand. This means that for a given volume of forecast error, the performance is better for higher demand levels or worse for lower demand levels (e.g. if there is a warm winter). The following chart compares the average absolute forecast error, measured in mcm/d, to average national demand. This shows that the volume of forecast error increased in 2010/11, but this was partially mitigated by the increase in total demand for that year. Therefore the incentive performance only showed a marginal deterioration.

Forecast Error and Average Demand



386 In 2011/12, the average absolute forecast error volume increased further, but average national demand reduced by nearly 40 mcm/d. This was due to a combination of a milder winter leading to lower LDZ demand and higher gas prices (relative to coal) leading to lower power station demand. This illustrates the influence of demand levels on the current incentive performance measure as demand levels can obscure actual forecasting performance and lead to windfall profit or loss.

Developments expected over RIIO-T1 period and TO plan Interactions

387 Demand can be driven by a range of factors including commercial drivers and changes in weather patterns that cannot be forecast with a high degree of accuracy before real time.

388 Where these factors are volatile and unpredictable, this can impact on our ability to forecast demand accurately. To correctly reflect the impact of these drivers, we would need to accurately forecast both the initial driver and its relationship with demand, which is challenging for many demand drivers.

389 As discussed earlier in this document, we expect an increasing level of volatility and uncertainty in demand and supply over the RIIO-T1 period including:

(a) continued growth in ‘short-cycle’ storage;

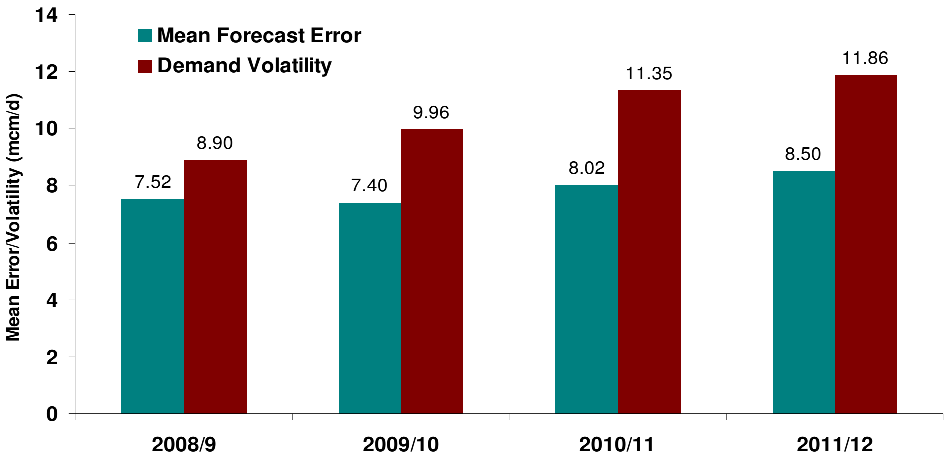
(b) more price arbitrage across fuel types and markets including increasing utilisation of the European interconnectors in response to maturity of EU energy market reforms;

(c) Increasingly dynamic operation of CCGTs to balance against the increasing volume of intermittent renewable energy; and

(d) the supply of gas from unconventional sources such as coal bed methane impacting Distribution Network demand

390 Price responsive demand has already increased with an increase in short-cycle storage and the impact of price driven interconnector demand variation, leading to a trend of growing demand volatility and associated impact on our ability to accurately forecast demand.

Overall demand volatility

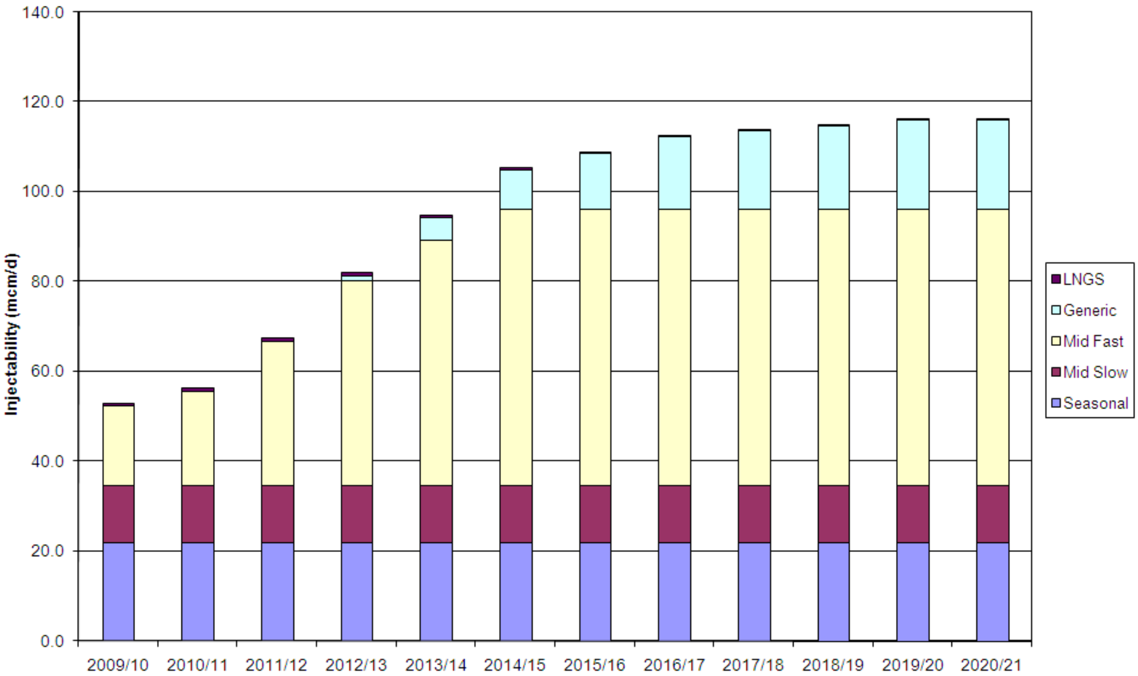


391 The chart shows that day to day demand volatility has steadily increased over recent years, and has a direct impact on demand forecasting. However, the rate of increase in mean forecast error is less than that of volatility. As we strive to address this challenge in improving forecasting processes and techniques, this will become increasingly difficult. The current incentive design takes no account of this fact.

‘Short-Cycle’ Storage

392 By 2020, we anticipate that injectability at storage sites will increase. This increase in storage injectability is predominantly expected from mid-range short-cycle plants, these will increase from circa 20mcm/d in 2010/11 to over 60mcm/d by 2021 with most of this in place by 2015. (‘Mid Fast’ represents short-cycle storage).

Storage Injectability



393 The operating regimes of these storage plants will create a number of forecasting challenges as they have the potential to be extremely responsive to small price differentials and can therefore re-profile their flows (i.e. move between injection and withdrawal) more frequently and provide less certainty over their flow patterns within and between days. In addition, we are seeking to forecast the behaviour of storage facilities prior to the occurrence of price signals which drive the behaviour of such facilities.

Price Arbitrage across Interconnectors

394 It is likely that gas flows across interconnectors will become more flexible as reforms to the European energy markets mature and develop. Accordingly, whilst analysis has indicated a degree of forecastability, there is also an inherent level of associated uncertainty with market prices that can drive interconnector demand changes. Consequently, these impact upon our ability to accurately forecast demand.

395 Akin to storage, we are seeking to forecast the behaviour of interconnectors prior to the occurrence of price signals which drive the behaviour of such facilities.

Dynamic Operation of CCGTs

396 The demand from CCGTs will become more volatile as they are used to support the intermittent operation of wind generation, resulting in fast ramping of gas demand. Though the level of wind generation can be forecast, the corresponding level of gas generation coming on or off the system is much more difficult to forecast because of the uncertainty over which flexible source of electricity may be used.

397 Historically the number of significant inter-day (difference between one day and the next) demand swings has been predominantly driven by temperature. Over the period, wind speed and installed wind capacity will also become important drivers of demand swing, potentially overtaking temperature as an inter-day demand driver by the end of the decade. This will drive both the frequency and size of significant inter-day weather driven demand variances.

398 Our modelling predicts that by 2020, due to the growth of wind, we are likely to see weather driven demand swings of 30mcm occurring at least 30 times in the year and swings of 70mcm or greater experienced on more than one occasion. This will adversely impact our ability to accurately forecast demand.

Impact of developments on the Gas Distribution Networks (GDN)

399 There are also a number of other developments on the GDNs which will have an impact on NTS demand requirements. The growing level of supply from connected unconventional sources of gas such as biogas and coal bed methane is inherently variable. As much of this supply is expected to be injected directly into the GDNs, this forecasting uncertainty will manifest within the GDN demand requirements.

400 Combined with a reduction in DN storage capability as gas holders and other local storage facilities are decommissioned, this creates uncertainty over the level and profile of the gas demanded from the NTS, both day to day and within day.

Interactions with the RIIO-T1 Plan

401 Our RIIO-T1 plan has identified our intention to deliver the necessary functionality required to build the enhanced tools and processes needed to manage an increasingly volatile operating environment, including the provision of scenario forecasting. The first stage of capability enhancements are in the areas of operational forecasting, real-time scenario analysis, control strategy optimisation and network status assessment.

402 The investment proposed in our March TO submission is principally aimed at within-day forecasting to enable efficient operation of the NTS whereas the incentivised forecast is focussed on the end of day position.

Proposed Approach

403 In its January 2012 Principles and Policy document, Ofgem expressed a view that it was important that we continue to be incentivised to provide accurate demand forecasts to market participants. It also suggested that setting a longer term 8 year target would allow us to develop improvements to the accuracy of our forecasts over a period of time.

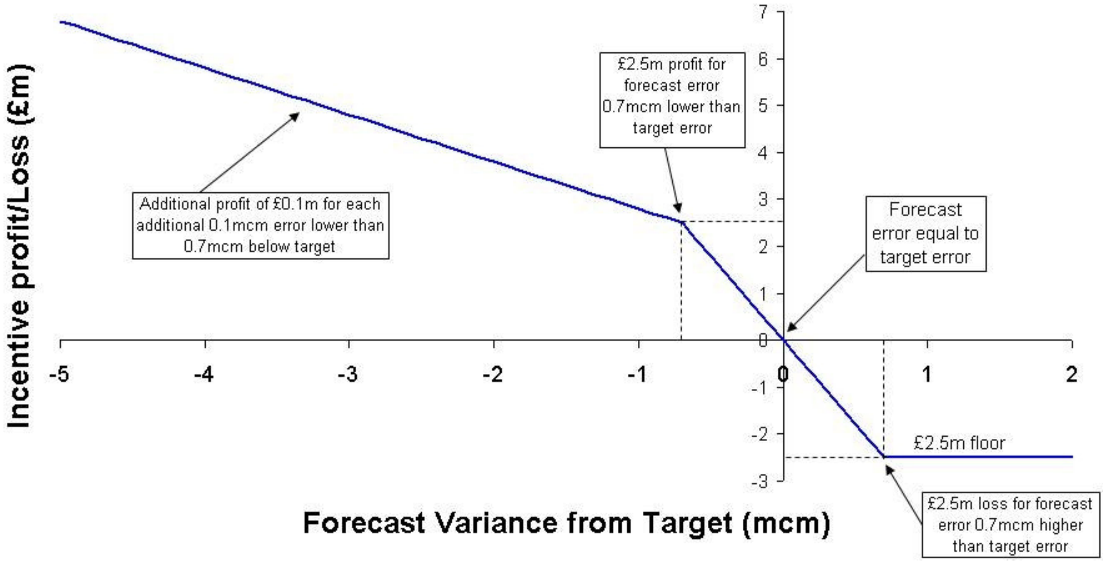
404 We propose to maintain the principle aim of the scheme to incentivise the minimisation of demand forecasting error but expand the number of forecasts covered by the scheme. We understand that this of value to the customer as it seeks to ensure that the industry has the best available information upon which to base its commercial decisions.

“” 405 In response to our consultation stakeholders confirmed that the current timed forecast (day ahead (D-1) at 13:00) remains a key source of information. We therefore propose that this forecast remains the focus of the NTS Demand Forecasting incentive scheme.

406 In addition, following stakeholder feedback, we propose to forecast Non-Daily Metered (NDM) demand at a national level which is predominantly made of domestic “” and small industrial and commercial demand. The proposed NDM Demand Forecasting Incentive Scheme would incentivise the accuracy of this new national NDM demand forecast.

NTS Demand Forecasting Incentive Scheme

407 Our proposed scheme for NTS demand forecasting measures our forecasting performance for the forecasts for each of the five days before the gas day.



Performance Measures

408 Through our consultation and workshops stakeholders have told us that the day ahead (D-1) 13:00hr forecast is most important to them and should therefore continue to be incentivised. There was less support for incentivising the forecasts ahead of D-1.

409 We propose an annual financial incentive scheme within an 8 year framework (i.e. for the duration of the RIIO-T1 period) in respect of the NTS Demand Forecasting scheme.

410 We are proposing to widen the range of forecasts covered under this incentive scheme to lend focus to earlier forecasts that stakeholders have noted are of particular use during more challenging periods of operation (e.g. when a Gas Balancing Alert has been called). We propose that NTS demand forecasts incentivised are those currently published at D-5, D-4, D-3 and D-2 in addition to the currently incentivised forecast at 13:00 D-1.

411 In order to mitigate the risk of windfall profit or loss associated with a percentage of demand measure, performance will be measured by reference to the average absolute error. The current method of dividing the absolute forecast errors by daily actual demand across the year creates the risk of windfall profit or loss in the event that demand is unusually high or low (as described in 'Background').

412 We have considered the use of other measures in order to drive demand forecast accuracy, and these include:

(a) Daily percentage error (performance measured each day)

(b) Absolute error (in mcm)

(c) Proportion of day on day variability achieved

(d) Improvement on market information (was our forecast better than the markets)

413 The advantages and limitations of the current and alternative measures are summarised in the Table below:

Measure	Advantages	Limitations
Annual % error (current measure)	Familiar and understood by industry	Windfall impact of demand
Daily % error	Easy to understand	Windfall impact of demand
Absolute error in mcm	Easy to understand Not affected by demand	
Proportion of variability	More reflective of the difficulty of the forecast	Harder to understand Not an absolute measure of performance
Improvement on market information	Demonstrates added value of forecast	Harder to understand Not an absolute measure of performance

414 Following consideration of the above and consistent with stakeholder feedback[48], we have concluded that "Absolute error in mcm" is the most appropriate measure of forecasting performance as it is easy to understand and minimises the risk of windfall profit or loss associated with a demand related metric.

"SSE support the proposal that an absolute forecast error is a more appropriate way of measuring forecast error rather than a percentage of demand."
SSE's response to National Grid's consultation, May 2012

[48] http://www.nationalgrid.com/uk/Gas/soincentives/docs/

Incentive Target

415 The year 1 target will be derived as the lower of 2011/12 and 2012/13 forecast performance (the 'Base Year'). In order to ensure the target remains reflective of forecasting conditions, a volatility adjustment will be applied. Targets for subsequent years will be set ex-ante as the target for year 1, with an ex post adjustment for any increase/decrease in demand volatility in the relevant Incentive Year relative to the Base Year.

416 Reflecting stakeholder support for a seasonal target the forecasting target error will be set by mean absolute daily error value (mcm) within season (summer being April to September inclusive, and winter being October to March inclusive);

"… and think targets should be set seasonally to reflect the higher costs of forecasting errors in the winter when gas is usually more expensive."
Energy-UK's response to National Grid's consultation, May 2012

417 The formula for determination of the seasonal targets for the base years are detailed in Appendix 7: NTS Demand Forecasting Supplemental Information.

Target Adjusters

418 Whilst there was stakeholder support for specific adjustment of the target error to reflect the volatility of individual demand components, there was uncertainty expressed in respect of the requirement for an overall volatility adjustment to the target forecast error.

419 We have concluded that for a long term scheme, an ex post overall volatility adjustment is most appropriate as it incorporates the actual impact of future volatility from all demand types. A simple and easy to understand approach, it is a single adjustment that can encompass all demand elements which have a net effect on demand volatility. The scheme structure would not need to be revised in order to reflect volatility from specific demand types not contemplated at the outset.

420 An alternative approach would be to use ex ante adjustments for specific demand components. In order to remain effective however, such a methodology would require frequent review in order to minimise the risk of windfall profit or loss. A further weakness is that scheme structure would need to be revised to encompass volatility from specific demand types not contemplated at the outset. Therefore an ex post overall volatility adjustment will avoid the risk of a windfall profit or loss associated with an ex ante forecast approach.

421 On this basis we have concluded that for a longer term scheme, the optimum approach is to include all elements of volatility into the adjustment to ensure that all potential sources are captured for the duration of the scheme.

422 Our analysis (detailed in Appendix 7: NTS Demand Forecasting Supplemental Information) demonstrates that there is a strong relationship between Demand Forecast error and average seasonal demand volatility. Therefore we propose to adjust the base target by the change in volatility relative to the volatility in the base year. It is worthy of note that in the event that volatility decreases from the base year this would create a negative adjustment to the seasonal target.

423 The adjustment for volatility in mcm will be determined on an ex post basis in accordance with the formula specified in Appendix 7: NTS Demand Forecasting Supplemental Information

424 Both target accuracy and absolute mcm error values will be weighted as follows in order to derive a single target and performance metric per season.

425 Given stakeholders' feedback that the D-1 13:00 is the most valuable forecast to them we have weighted the forecasts accordingly.

NTS Demand Forecast timing	Weighting (%)
D-5	10%
D-4	10%
D-3	10%
D-2	20%
D-1 13:00	50%

426 On this basis, the overall target and overall mcm error values shall be calculated in accordance with the formula specified in Appendix 7: NTS Demand Forecasting Supplemental Information

427 A weighted average (2:3 for Summer: Winter) will subsequently be used to determine overall annual performance. This will be applied as follows:

$$\text{Annual Performance} = \left(\left(\text{Overall Summer Error} - \text{Overall Summer Target}\right) * 0.4\right) + \left(\left(\text{Overall Winter Error} - \text{Overall Winter Target}\right) * 0.6\right)$$

Value

428 In order to mirror the current incentive profile, the upside and downside gradients will give an annual profit or loss of £2.5m for a 0.7mcm variance above or below (respectively) the target. There is a shallower upside gradient for variances more than 0.7mcm below the target. On the downside, the collar is £2.5m. The increase in value compared to the current scheme reflects the supplementary value of the additional forecasts which are proposed to be subject to the incentive scheme.

NDM Demand Forecasting Scheme

429 Through this year's consultation, a number of stakeholders have indicated that improvements to NDM forecasts would be of value as this forecast helps inform their NDM nominations and their balancing action decision process.

"Given National Grid's expertise in this area we believe there would be value in incentivising the accuracy of the NDM forecasts. This should help to encourage National Grid's support and engagement in these important industry forecasts."
EDF's response to National Grid's consultation, May 2012

430 The current NDM forecast is produced in accordance with a methodology contained in provisions of the UNC [49].The key factors that affect the accuracy of this are the

[49] The NDM Output Nomination required pursuant to UNC TPD C1.5 (NDM Output nomination at D-1 14:00

GDN's demand forecasts (which are not incentivised) and the accuracy of the Daily Metered (DM) shipper's nominations (which are weakly incentivised through scheduling charges). Evidence from shippers suggests that the level of forecast error introduced by this process can be large.

431 This is distinct from the NTS forecasts that we currently produce as the derivation methodology is not constrained by the UNC. Accordingly, as operator of the NTS, there is a question as to whether it is appropriate for us to consider incentives for an area in which we currently have no input or control.

432 If we were to be incentivised to improve the accuracy of the NDM forecasts there are two potential options available. The first option would be to look at improvements that could be made to the existing process: we expect that this would require UNC changes[50] and significant changes to the Gemini system to deliver.

433 An alternative approach could be for us to invest in a new alternative NDM forecasting capability to run alongside the existing processes. Development of such capability would require time and a level of cost yet to be determined. It may be possible to incentivise any additional forecasts post development.

434 Although some stakeholders are clear on the issue they wish to see addressed – the accuracy of NDM forecasts - we do not believe that there is a clear consensus on the action that they wish us to take in response.

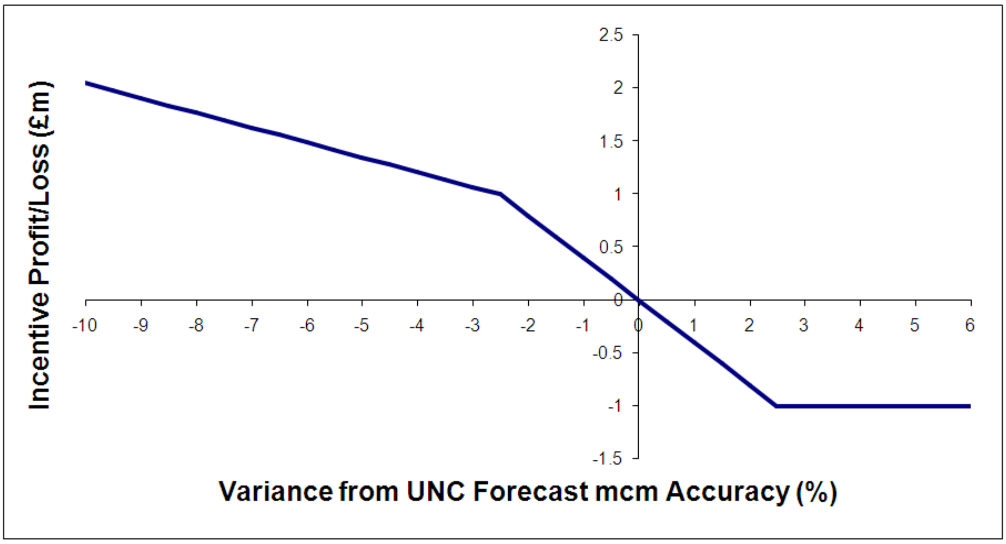
435 We believe a pragmatic way forward at this stage is to investigate whether the provision of a national NDM forecast is of benefit to shippers. This could be achieved in time for the commencement of the RIIO-T1 period, and without the need for changes to UNC or existing systems.

436 We are therefore proposing an annual financial incentive scheme within an 8 year framework (i.e. for the duration of the RIIO-T1 period) - the NDM Demand Forecasting Scheme. This will require us to produce a national NDM forecast at 13:00 D-1, with performance measured by the accuracy of the new forecast relative to the accuracy of the existing UNC forecast published at the same time. It is important to note that the NDM forecast we propose to produce is supplementary to, and therefore will not replace, the existing forecast provided pursuant to the UNC.

"There could be merit in NGG being incentivised on the day ahead NDM forecast in addition to the total demand and to ensure that these forecasts show an evolution of demand rather than an NDM forecast jumping around within day due to external factors."
Energy UK's response to National Grid's consultation, May 2012.

437 The overall scheme is illustrated in the following diagram:

[50] All UNC parties have the ability to raise Modification Proposals to the UNC



438 We are proposing to restrict the provision of this new forecast to working days only (i.e. generally forecasts for Tuesday to Saturday inclusive) at this stage. However, we will review this position in conjunction with the industry.

439 We consider that the new NDM demand forecast scheme should mirror the proposed NTS Demand Forecasting incentive profile. Accordingly, the upside and downside gradients will give an annual profit or loss of £1m for a 2.5% variance above or below (respectively) the target. There is a shallower upside gradient for variances more than 2.5% below the target. On the downside, the collar is £1m. This would be reached by a variance of 2.5% greater the target accuracy. Annual performance would be determined on the basis of the average daily variance within the incentive year.

Length

440 We propose an annual incentive scheme within an 8 year framework with a midpoint review after four years. This review will cover the continuing suitability or otherwise of the target adjustment mechanism.

Methodology Review

441 As the NDM forecast will be a new service with a new incentive measure we propose to review its operation after the first year to ensure that it is operating as intended. Any changes to the scheme can therefore be considered from the commencement of year three.

442 Our proposals for the Demand Forecasting incentive identify a number of principles which can be applied for the duration of the RIIO-T1 period, however we are proposing that a midterm review (i.e.: review to take place within year four with any changes taking effect from the commencement of year five) is undertaken to determine whether:

(a) The NTS Demand Forecasting incentive scheme is operating as intended including the uncertainty mechanism for volatility;

(b) Whether it is appropriate to include within-day forecasts in the NTS Demand Forecasting incentive scheme;

(c) The NDM Demand Forecasting scheme is working as intended; is the information still valued and are any additional timed NDM forecasts valued by the industry; and

(d) The implementation of smart metering mandates has any implications for the derivation of future demand forecasts.

Delivering Benefits for the Consumer

443 The purpose of the provision of demand forecasts is to provide the industry with information to aid trading and balancing efficiency. Accordingly, on the basis that an accurate demand forecast leads to efficiencies, this should enable the minimisation of any risk premium eventually levied to consumers in supply costs.

444 Consistent with previous stakeholder feedback, responses to our latest consultation indicated that demand forecasting remains of value to our customers, indeed requirements for additional demand forecasting have become apparent through this engagement process. In response, we have identified a set of proposals which are aimed at addressing the requirements of our customers.

Operating Margins

Overview

445 Operating Margins (OM) gas is used to maintain NTS pressures in the immediate period following operational stresses and before market balancing measures become effective. Such stresses may result from supply failure, unanticipated demand changes or failure of an NTS pipeline or associated equipment. A quantity of OM is also procured to manage the orderly run-down of the System in the event of a Network Gas Supply Emergency (NGSE) whilst firm load shedding takes place. OM is provided by storage facilities, Liquefied Natural Gas (LNG) importation facilities, offtake reduction and supply increase services.

446 We only have minimal control over the costs of OM given the market driven OM requirement sensitivities, the relative illiquidity of the market and limited scope for greater liquidity for some requirements types. Therefore, we propose that Operating Margins costs be subject to a pass through arrangement and that a reputational incentive is put in place to ensure transparent reporting on how we continue to facilitate development of a competitive market for OM services.

447 An internal review of Operating Margins is underway, with a view to ensuring that OM requirements, calculation methodology and service provision is fit for purpose for the RIIO-T1 period. We are proposing to reflect on this upon completion of the review. We may at that time seek to introduce further incentivisation.

Background

448 OM is a service required by the SO in order to reduce the likelihood of an emergency on the NTS or in the event of an emergency, to ensure the safety of all users on the system.

449 The Operating Margins is required in a number of different scenarios to either reduce the likelihood of a Network Gas Supply Emergency or to manage the system safely during an emergency. This forecast requirement detailed below is used within cost estimates later in this document. As this is a forecast requirement, it is subject to change, such as following the experience of the latest winter supply and demand patterns.

450 The OM requirement is made up of a number of different parts. The three categories of which are:

(a) Group 1: Managing pressures and the safety of the system following a supply failure or forecast demand change;

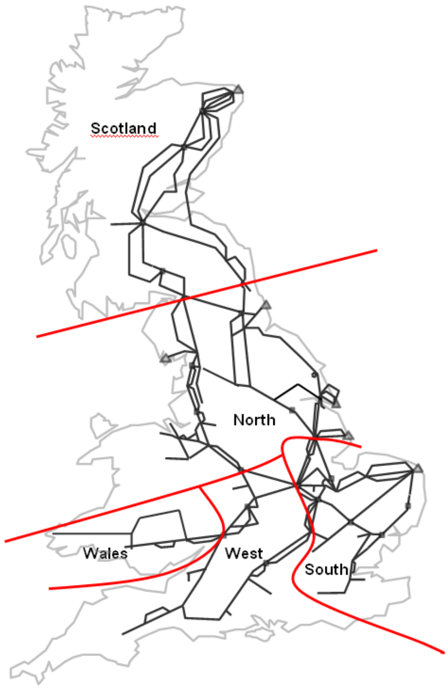
(b) Group 2: Support network pressures in the 24 hours following compressor and/or pipeline failures (which can require OM to be held both within locational zones and nationally); and

(c) Group 3: 'Orderly Rundown': Used to effect isolation of Very Large Daily Metered Customers (VLDMCs) and Local Distribution Zone Daily Metered

(LDZ DM) loads such that the remaining predominantly domestic demand can be met with supply available at the time[51].

451 Each of the Operating Margins Requirements will need a volume of gas delivered within a short time period. The rate at which the gas can be delivered is often referred to as the deliverability. Some of the Group 2 requirement is tied to a specific locational zone – as local network pressures cannot be maintained for sufficient time to allow for the transportation of OM services located further away. Figure 2.1 shows the locational zones for Operating Margins for the years 2011/12 and 2012/13.

Operating Margins Locational Zones



452 We currently have the ability to procure OM in the form of gas held in storage or as a deliverability option from either a demand side (turn down) provider or from a supply increase (turn up) provider. Current providers are:

(a) Natural Gas Storage Facilities;

(b) Liquefied Natural Gas (LNG) Storage Facilities; and

(c) Liquefied Natural Gas (LNG) Importation Facilities with Storage.

(d) NTS directly connected loads, (e.g. Power stations)

453 Services procured from National Grid LNG Storage are subject to regulatory provisions, whilst services from other facilities are under normal commercial terms.

Current Incentivisation

[51] Assumptions made in the calculation of the Orderly Rundown requirement are published within the Operating Margins Statement which is published here: http://www.gasgovernance.co.uk/OpsMargins

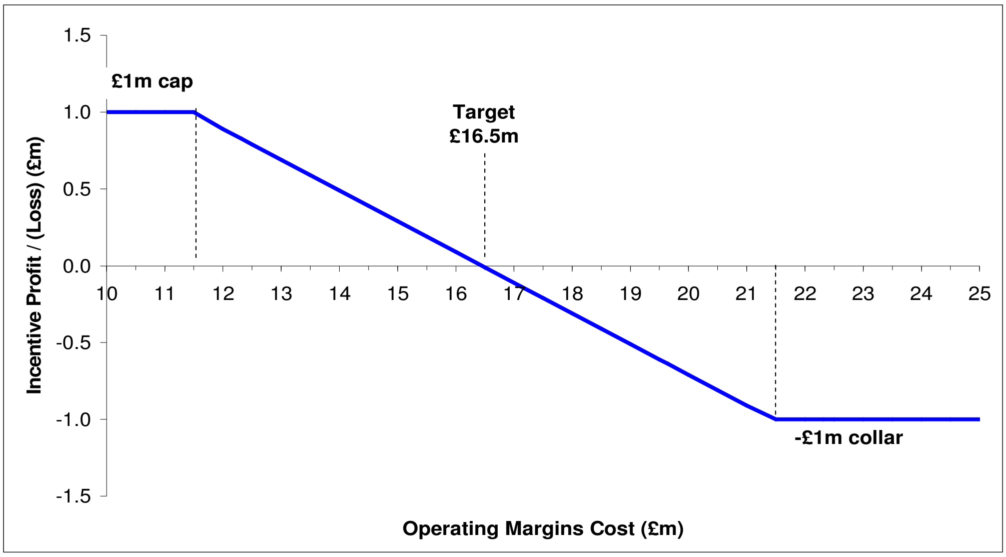
454 The review of the incentive carried out in 2010/11 concluded that given contestability was in place, an incentive which covered both 'Availability' and 'Utilisation' costs should be introduced. This was agreed for a 2 year period and expires in March 2013. The Availability target for 2011/12 was set to the costs incurred in that tender process, with the Availability target for 2012/13 5% lower than the 2011/12 target. This replaced a previous arrangement whereby only utilisation costs were incentivised due to market uncertainties.

455 There were challenges in producing accurate cost forecasts during the negotiations due to the uncertainty created by the review of LNG storage regulated prices that was being undertaken at the same time. This review resulted in a significant change in those price levels.

456 The utilisation performance measure is based on average historical volumes (33.4GWh). A utilisation cap was introduced which related to previous maximum annual utilised volume (78.1GWh) reflecting that we do not have full control over whether or not to utilise OM gas. The need may be driven by factors outside of our control, for example, a supply loss. The price used for calculating the utilisation cost performance measure was based on a volume weighted average of prices from that tender round.

457 The 2012/13 scheme is summarised in the following diagram

OM Incentive for 2012/13



458 Performance in the Operating Margins scheme has been mixed for both customers and ourselves. In the first year of the current scheme (2011/12) we achieved a profit of £0.36m mainly attributable to efficiencies in the reprofiling of OM stock during the year and there were no issues on the NTS that led to the requirement to use OM during the incentive year. For 2012/13 we currently forecast a loss of ~£0.5m on the scheme as a result of increased prices for availability of services coupled with the 5% lower target than in 2011/12.

Volume and Price Uncertainty

459 The volume and deliverability requirements for OM change from year to year due to a range of factors that are largely outside our control which include:

(a) Change in demand level: This can lead to a change in the volume of OM required to maintain a safe system in the event of an OM utilisation

(b) Changes in supply forecasts: Supply loss OM is affected by supply forecasts as the OM booking is based on credible single points of failure at individual terminals; and

(c) System reinforcements: These can, in some cases, reduce the locational element of the OM requirement (e.g. if a second pipeline is built in an area)

460 OM is purchased to meet safety case and UNC requirements, to ensure the network remains robust for a range of scenarios such that we procure the requirement at a national and locational level that is deemed to be safe.

461 We procure OM in accordance with the rules set out in UNC Transportation Principal Document Section K, leading to an annual tender process being carried out. The annual requirement in volume terms for Operating Margins in 2012/13 is approximately 1,100GWh which in comparison to the overall demand in the market (assuming an average demand of ~260mcm/day) accounts for approximately 0.1% of the annual demand level.

462 Recent tender experience has shown that whilst there is a market for the OM provision, the market is relatively illiquid for a number of the individual requirement types, and we are reliant on a number of specific providers, the pricing of services is subject to the tendered prices and the level at which these are received is out of our control. Recent tender information can be found on our website[52].

463 Since 2008, we have expanded the range of OM service providers, as required by the OM contestability licence condition[53]. This has been achieved via a combination of increasing the number of storage sites which participate in the tender, and progressing a change to the Safety Case to facilitate demand side service provision. For 2012/13 we have contracted with all types of storage facility (Long, Medium and Short range), LNG importation facilities and Demand side response. For demand side we have both portfolio and single site providers.

464 The only additional area that we could pursue is Interconnectors, however the EU Codes are focussed on Interconnection Points and therefore it would be inappropriate for us to pursue solutions in this area until we have assessed the impact of the new EU Codes.

465 We have an active communications strategy with existing and potential providers and ensure information such as standard contract forms and tender reports are available to encourage parties to tender into the process and reduce any administrative burden on potential providers.

466 We believe that the aims of the contestability licence condition have been met and that the processes to encourage providers into the market are embedded within the business. Therefore we believe it is appropriate to remove the specific contestability licence condition, and to replace it with a reputational incentive to ensure transparent

[52] Tender information reports are available from: http://www.nationalgrid.com/uk/Gas/OperationalInfo/GasOperatingMargins/

[53] Special Licence Condition C25

reporting on how we have continued to facilitate development of a competitive market for OM services.

Developments expected over RIIO-T1 period and TO plan Interactions

TO Plan

467 The RIIO-T1 business plan highlights the link between the SO and TO in the provision of OM, particularly with respect to the South West and the future of the Avonmouth LNG storage facility[54].

468 In the RIIO-T1 business plan several options were outlined as to how best meet network requirements (including OM) in the South West which are currently met using the Avonmouth LNG facility. These options are as follows:

(a) Option 1: "Enduring Avonmouth" permitting investment at Avonmouth to allow the facility to meet the necessary requirement on an enduring basis.

(b) Option 2: "Alternative provider" re-exploring whether these requirements can be met, both in the short term and the longer term, through commercial contracts with alternative providers in the South West.

(c) Option 3: "Pipeline investment" investing in new pipeline assets which removes the relevant OM requirement and some other network services at Avonmouth.

469 Historically, a proportion of both national and locational OM requirements have been met using gas held in the LNG Storage facilities and we expect a continuing South West locational OM requirement throughout the RIIO-T1 period unless the Pipeline solution is taken forward. The South West locational OM requirement should be resolved if the pipeline investment detailed in the RIIO-T1 business plan is complete.

470 For any OM that is required at Avonmouth, either until other solutions can be put in place or in the longer term, the cost of this service will need to be considered. The cost of OM at Avonmouth is subject to regulated prices ("C3") that are set out in our NTS licence. These prices expire on the 30th April 2013, therefore whatever pricing structure or method of funding agreed for the provision of OM at the Avonmouth LNG storage facility in the RIIO-T1 business process will need to be reflected in any incentive or cost allowance. This is particularly important should no commercial services be offered by the facility.

471 Net Present Value (NPV) and risk analysis has identified that Option 3: 'Investment in a new pipeline in the South West' is the optimal solution.

OM Review

[54] Further details are available in our detailed TO plan that is available here: http://www.nationalgrid.com/NR/rdonlyres/87A406CE-136F-4F7C-936F-ADBF0D8F86C3/52255/2012_NGG_detailed_plan_redactedsecure.pdf

472 We are currently undertaking a review process for OM to ensure that the definitions and calculation methodology remain fit for purpose for the RIIO-T1 period.

473 The key objective of the review is to ensure that OM is modelled and defined properly within the changing supply and demand environment to ensure the network remains safe and is supported by an appropriate procurement strategy.

474 The review is expected to:

(a) Clarify OM requirement definitions or all types of OM

(b) Develop potential OM service types to ensure OM requirements can be met in the changing environment.

(c) Lead engagement with industry to discuss potential service provision mechanisms.

(d) Work with the HSE to demonstrate the effectiveness of any new service provision as appropriate.

(e) Contract development for any new service structures.

(f) Initial tender with new types of service provision.

475 Although OM is currently procured via an annual process, we are reviewing whether it is appropriate for different categories of OM to be procured in different ways. For example, we have instigated a process to progress "Option 2" in the TO submission, and are in the early stages of running a long term tender process for South West locational OM. This provision would specifically cover the period up to the expected commissioning date of the new pipelines in the South West referred to above.

476 Shorter term procurement may be appropriate for other requirements that are driven by underlying supply and demand assumptions that change with market dynamics.

477 We intend to explore how alternative procurement options could be taken forward in consultation with the industry once we are confident that any identified changes do not detract from our safety obligations.

478 Following the OM Review, it may be appropriate to revisit whether there is an appropriate level of control in order to enable incentivisation of OM. Given the range of activities that would lead to new OM services being put in place, we consider that April 2014 is the earliest timescale that an incentive could be put in place.

479 Similarly, we would like to explore options for provision of services from interconnectors. However with the current background of EU code development leading to uncertainty in how interconnectors will be operated, we feel that any development of an interconnector service should be progressed in line with EU code developments.

Proposed Approach

480 In January 2012 Ofgem outlined their initial view of a cost minimisation target for OM which would be for 8 years with a sharing factor of 20%[55].

481 It is appropriate to ensure that any services are procured efficiently, however it is not appropriate to have financial cost incentives which have the effect of encouraging reduction of volumes both geographically and nationally below a level which is deemed to be safe.

482 With the limited level of control over the costs of OM given the market driven OM requirement sensitivities, market illiquidity and limited scope for greater liquidity for some requirements types, we propose a reputational rather than financial incentive resulting in a pass-through of costs subject to a regulatory efficiency review as appropriate to ensure an requisite level of oversight over the costs paid by consumers for this service.

483 As discussed previously in this document, since 2008 we have increased the range of service providers such that currently the only provider type we are unable to contract with is Interconnectors. We would need to act in accordance with our licence to ensure competitive tenders and continuing promotion of competition but all costs would be passed through.

484 Following the OM Review, we expect to revisit whether there is an appropriate level of control over OM costs in order to enable incentivisation. Given the range of activities that would lead to new OM services being put in place, as described above we consider that April 2014 is the earliest timescale that an incentive could be put in place for the remainder of the RIIO-T1 period, although if the new service types are complex this timescale may be longer.

485 This timescale would provide us with the opportunity for the outcomes of the review to be more certain, both in terms of discussions with the HSE in respect of our safety case and with the industry around potential procurement options. Consequently, this would prevent the potential creation of windfall gains or losses from any changes that result from the OM review which would not be economic, efficient or aligned with Ofgem's SO incentive principles.

486 If, going forward, new incentive arrangements are shown to be appropriate then we would revisit how an appropriate incentive could be designed in consultation with the industry.

Delivering Benefits for the Consumer

487 OM is required to allow us to safely manage the NTS at time of operational stress, both to help prevent a gas supply emergency and to manage one if it occurs. We do not believe that it is appropriate to have financial incentives which drive behaviour to reduce the volumes of this service to a level which is below that which is safe.

488 There has been a significant change in the makeup of service providers over the last four years, and costs have in the main decreased, but we are now at a stage where our level of control over the requirement and costs of OM is limited. Therefore, we

---

[55] http://www.ofgem.gov.uk/Pages/MoreInformation.aspx?docid=277&refer=Markets/WhlMkts/EffSystemOps/SystOpIncent

consider that it would not be in the best interests of consumers to develop an OM incentive scheme under the current arrangements as this could lead to a potential windfall loss or gain due to these market uncertainties.

489 The review of OM which is ongoing will set out a clear way forward in terms of service definition and provision, and we propose to assess forms of incentivisation in consultation with industry when this review is complete.

Greenhouse Gas Emissions

Overview

490 NTS assets can release gas as an inherent part of their commissioning, operation, maintenance and decommissioning. Emissions characteristics frequently reflect the understanding of the associated social costs, together with the cost of abatement, at the time of the asset design. As environmental awareness increases, the costs and benefits of operational decisions and alternative investments are being continuously reviewed.

491 The TO's proposed capital plan for the RIIO-T1 period responds to legislation and stakeholder views aimed at reducing the impact of our networks on the environment. The plan includes the modification of compressor stations to ensure compliance with increasingly stringent local air quality and emissions regulations.

492 Given the abatement of gas release from NTS operation remains largely uneconomic in isolation, it is generally bundled as part of wider works.

493 We, in conjunction with the TO, are currently undertaking a detailed review of specific asset venting characteristics under Special Licence Condition C28. The research associated with this review is expected to deliver a better understanding of the scale, scope and potential for reductions from existing assets and alternative investment. The review will help inform TO investment decisions, and facilitate a long term SO incentive to reduce Greenhouse Gas Emissions from the operation of the gas transmission system.

494 The current SO incentive seeks to minimise the release of gas from compressors and their associated pipework wherever economical and operational decisions permit. Compressors are currently the most significant and well documented venting source, based on our current information. There are, however, uncertainties in the outlook for supplies and demand over the RIIO-T1 period, and the extent to which this will affect existing patterns of compressor operation, fuel consumption and consequential venting.

495 We propose to retain the existing scheme structure for compressor venting for at least one year, pending the ongoing research being carried out under Special Licence Condition C28. The scheme will incorporate a target based upon historic outturn venting volumes and include an efficiency factor to reduce compressor related emissions below the existing levels. In addition we propose a 50% sharing factor. We then propose to update the scope of this incentive following the detailed review and an associated data collection exercise.

Background

496 As part their operation, NTS assets release greenhouse gas emissions. This release, known as ‘venting’, occurs to varying degrees from seven NTS separate asset types:

(a) Compressors and associated assets

(b) Pipelines systems undergoing maintenance[56]

(c) PIG traps

(d) Filters

(e) Scrubbers

(f) Measurement, including chromatographs

(g) Valves

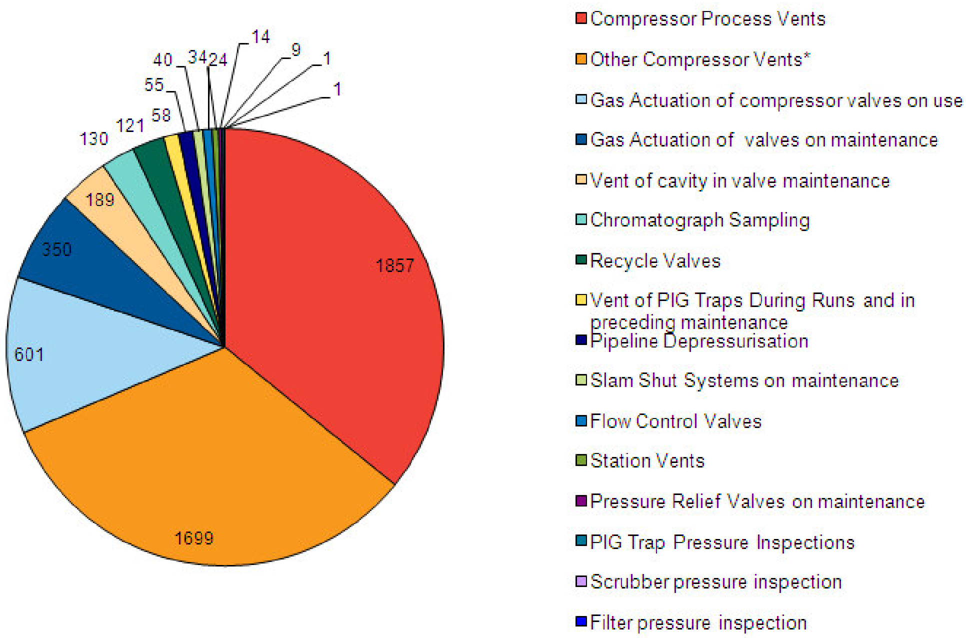
497 Each asset type has different characteristics including the extent to which gas is inherently released, or periodically vented as part of its operation or maintenance. For example, the de-pressurisation of a pipeline to enable inspection or remediation from third party damage is an infrequent occurrence, necessitated for safety reasons, resulting in a large volume of gas being vented (averaging around 23 tonnes per event). At the other end of the spectrum, chromatographs release small amounts of gas continuously given their inherent design characteristics.

498 Based on existing knowledge and data, we believe that routine compressor venting accounts for around 70% of the total NTS venting that is currently quantified. Findings from Special Licence Condition C28 research will be used to better understand and quantify the extent of natural gas venting from compressors and a number of other assets that are installed in the NTS.

499 The following diagram illustrates how different asset types and processes are currently believed to contribute to venting.

[56] Maintenance is comprised of two elements; planned maintenance underpinning system reliability and compliance with safety regulations, and reactive maintenance to address unexpected system issues.

Estimated venting by emission point in 2010 (in tonnes natural gas)



500 Venting of natural gas to atmosphere is now known to have a detrimental impact on our environment, with a tonne of natural gas having the equivalent impact of approximately 20 tonnes of CO_2. Quantifying its impact, and using DECC's assessment of the social cost of carbon enables us to optimise investment and operational decisions for existing and alternative assets.

501 Venting levels are significantly affected by activities that are required to meet safety and environmental legislation. Both are risk based processes where reasonable cost to reduce risk or harm or damage is determined by the operator. To control and minimise the extent of gas release, options need to be considered, optimising between safety, operational, capital and environmental costs:

(a) Operational strategy (e.g. optimisation between keeping a compressor in a pressurised state and the seal leakage venting and energy use whilst in this state);

(b) Tools that may be used to reduce the impact of an event or series of events (e.g. use of mobile recompression rigs or flaring for large de-pressurisations of gas associated with pipeline maintenance); and

(c) Capital Investment, using commercially available products, to adapt or replace assets and reduce or eliminate gas release (e.g. storage, consumption or recompression of gas that would otherwise be vented).

Current Greenhouse Gas Emissions Incentive

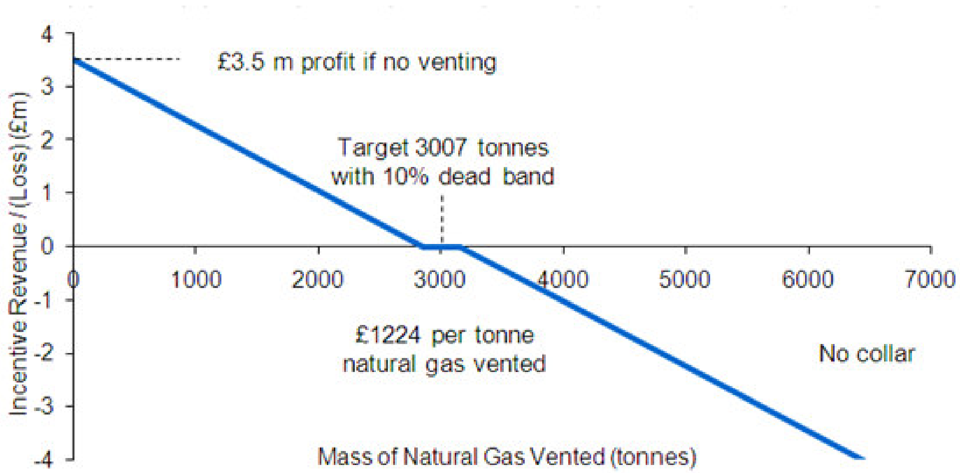
502 The current Greenhouse Gas Emissions from Compressors incentive covers venting from compressors and associated pipework – the best understood element of gas release. The scheme incentivises us to make the trade-off between choosing to depressurise both gas and electric compressor units (venting the gas within them) or to keep units on standby, increasing electricity usage from ancillary equipment at the compressor station.

503 The incentive target for 2012/13 is 3,007 tonnes reflecting a historic baseline level of gas release associated with the existing fleet of compressors, their inherent design, obligated inspection and maintenance, and the operational requirements arising from use.

504 The scheme includes a 10% deadband reflecting uncertainty in the annual target. For every tonne vented above or below the deadband, we are subject to a penalty or payment of approximately £1,224 per tonne. This value was determined from the carbon equivalence of the gas, and the DECC non-traded price of carbon reflecting the social cost.

505 With no sharing factors, the scheme theoretically caps our benefits at £3.5m per annum with no collar (floor) on the losses we can incur. The following diagram illustrates our current incentive:

Greenhouse Gas Emissions Incentive for 2012/13



506 The following Table illustrates our performance since the introduction of the incentive in 2008/09.

Year	Target	Performance	Venting Price	Incentive Revenue
2008/09	2,086 10% dead band	1,850 tonnes	£437 / tonne	£58 k
2009/10	1,977 10% dead band	1,634 tonnes	£574 / tonne	£140 k
2010/11	3,007 10% dead band	3,346 tonnes	£1,100 / tonne	- £209 k
2011/12	3,007 10% dead band	3,000 tonnes	£1,145 / tonne	£0k
2012/13	3,007 10% dead band	Forecast 3,267 tonnes	£1,224 / tonne	Forecast -£130k

507 The methodology used to calculate the venting from compressors was updated in 2010/11. This change to increase the accuracy of the mass of venting led to an increase in the reported mass from 1 April 2011 onwards.

Developments expected over RIIO-T1 period and TO plan Interactions

Impact of the changes over the RIIO-T1 period

508 A number of key developments are expected to take place within the RIIO-T1 period and these are likely to change the venting characteristics of some assets. For example, asset replacement will be undertaken to comply with the Industrial Emission Directive (IED) and the implementation is also required to be compliant with Best Available Technique (BAT), which focuses on local air quality. BAT is based around the delivery of optimal investment solutions and takes account of all factors including fuel consumption, combustion and vented emissions

509 The proposed investment plan and final design solutions will impact on many characteristics of NTS compressors, including inherent and optional venting necessitated from their operation. Inspection and maintenance requirements may also differ as these are brought into operation.

510 The RIIO-T1 plan also responds to increasingly stringent regulation to maintain the integrity of high pressure systems, and the aging profile of NTS pipelines and associated assets. As a result, maintenance requirements and any associated venting is likely to change.

Operating in a changing supply and demand environment

511 Compressors are used to safely manage system pressures and transport gas from NTS entry to exit points. A number of factors determine the underlying operational compressor strategy and our ability to optimise between venting and retaining units in different operating modes.

512 Over the RIIO-T1 period we expect to see additional volatility and uncertainty in the location and level of supply and demands on the NTS. The combined effect will alter flow patterns further on the NTS away from historic, relatively steady state predictable North to South flows, to greater diversity in the market's use of network capacity necessitating greater compression flexibility. As such, there is considerable uncertainty in the future operational compressor strategy and consequential venting.

Calculating venting and data collection

513 As detailed earlier, we are working hard to fully understand the scale and scope of venting across our network assets. Research being conducted pursuant to Special Condition C28 aims to increase the accuracy of vented emissions quantification for seal and valve leakage, station vents, valve maintenance and valve actuation related to compressor operation. Having improved our understanding and refined the calculation methodologies, a period of data collection will be required to understand the impact of the research.

514 We are also working on a number of Innovation Funding Incentive projects to develop alternatives to venting natural gas. These projects are summarised in the table below:

Current IFI Project summary

Vent Sources / Activities	Magnitude of Emissions		Degree of Influence to Reduce Impact of Venting	Potential Venting Reduction Actions	Special Licence Condition C28 Current Status
	Per Event	Per Asset			
Chromatograph sampling	N/A	Medium	Medium	Currently, gas chromatographs continuously bleed gas to speed up the the transit of gas from the insertion probe to the chromatograph. This project is designed to review alternative methods to provide sufficient transit speed	A comparison of different analysers has quantified the vent reduction by the use of a low volume probe and identified other potential technologies in this field. The project report is due by 31/07/2012
Alternatives to Venting	Very Low	N/A	Low	This project investigates the use of adsorbed natural gas storage as an alternative to venting at compressor stations. A decision support tool has been produced to compare options recompression and flaring for venting through compressors and pipeline decommissioning and pigging operations.	The adsorbed natural gas field trial will begin in August 2012. The decision support tool will be implemented and used for reporting purposes from July 2012

Proposed Approach

Aim of the Greenhouse Gas Emissions incentive

515 We believe the scope of our risk and reward under this incentive should be limited to the assets in operation. These assets are independently designed and commissioned to meet prevailing legislative and corporate objectives including an economic test of the costs associated with minimising or eliminating gas release by undertaking capital investment.

516 The existing incentive enables us to quantify the social cost of gas venting and to include this in decisions where we have some degree of direct control. As such we propose to build upon this framework, sharpening our incentive and then potentially extending its scope when the results of the detailed study have been assessed.

Proposed Interim targets and adjusters

517 Pending the completion of the ongoing review, improvements in quantifying emissions, and refinement of the investment designs, we propose to retain the existing scheme structure (i.e. measuring venting from compressors and associated pipework) in the period leading up to the completion of analysis of Special Condition C28 research findings.

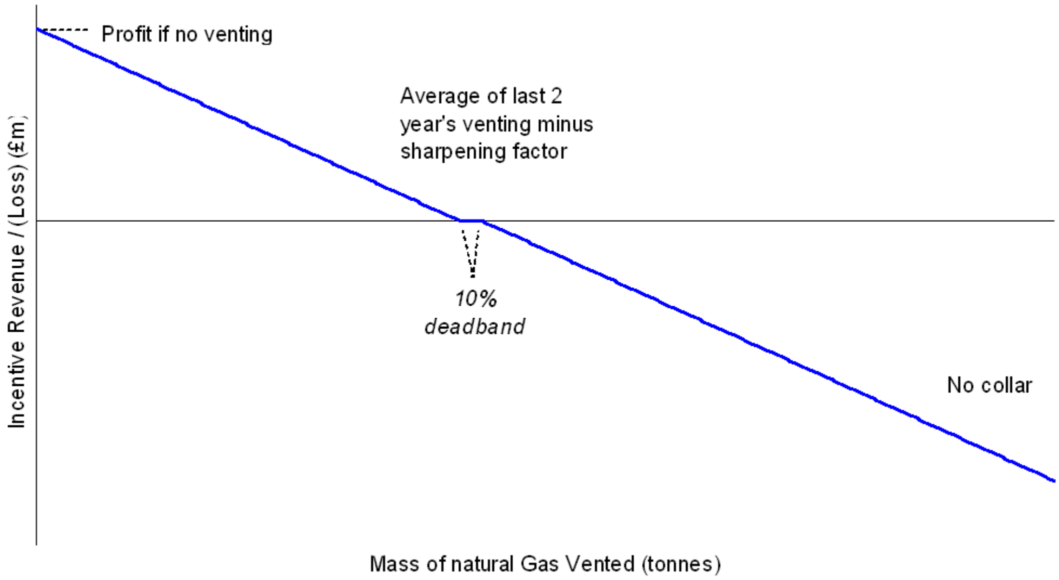
518 We propose that the emissions volume target for the interim period should be set as the average outturn for the preceding two incentive years minus an efficiency factor of 1.74%, which corresponds to the annual factor used by EU Emissions Trading System. We propose a 10% deadband and no caps or collars (as per the current scheme structure) and a 50% sharing factor to align with other incentives which interact with gas venting, specifically NTS shrinkage, and TO revenue streams.

519 For every tonne vented above or below the deadband, we propose that we be subject to a penalty or payment equal to the carbon equivalence cost of the gas, valued at the prevailing non-traded price of carbon as specified by DECC.

520 This would reflect the nature of the existing asset base and the improvements we have made in operating it, increasing our challenge further still by applying an annual sharpening factor.

521 The interim scheme is summarised in the following diagram:

Interim Scheme Structure



Proposed Enduring Incentive Overview

522 Beyond the completion of Special Condition C28 research, we propose to develop an enduring framework that incentivises us to reduce the operational venting of natural gas in cases where it is economical and efficient.

523 The increased venting knowledge that we derive from Special Condition C28 research will be used to develop a significantly more robust methodology relating to measurement of natural gas venting. This could then be further developed as knowledge and certainty increases during the RIIO-T1 period.

524 Our increased knowledge of venting will allow us to more effectively trade off the costs and benefits of daily operation and to develop tactical solutions for maintenance and inspection activities.

Setting the target

525 We propose that the target will incorporate agreed findings from Special Condition C28 research and the annual baseline will be determined by a robust methodology that reflects the level of venting that is inherent within the network's design, together with market demands for and use of capacity and network flow variations.

526 It will be based on annual volume targets that reflect the baseline level of gas expected to be released from our network assets, together with a prevailing financial

measure that reflects the social cost[57] of the associated venting. It should also adapt to uncertainties in compressor utilisation, and proposed investment.

527 It should differentiate between mandatory compliance-based requirements that lead to venting and other activities that can be affected by the SO.

528 We propose:

(a) Maintaining a 10% deadband around the baseline volume given the uncertainties in setting the overall target level;

(b) Retention of the carbon equivalence and price variables applied in the existing scheme and to update these based on prevailing knowledge;

(c) A 50% sharing factor of annual performance relative to the cost target. This ensures the scheme is aligned with other incentives which interact with gas venting, specifically NTS shrinkage, and TO revenue streams; and

(d) No caps or collars in order to maintain the incentive to optimise the level of venting even in high and low venting scenarios.

529 The methodology for volume determination would be published ahead of each incentive year with indicative target volumes. We will, as part of this process, consult with our stakeholders to ensure their views are also reflected through the methodology.

Scope of Special Condition C28

530 Special Condition C28 was introduced in order to enable better understanding and quantify vented emissions from a number of NTS assets. Ofgem issued a direction obliging us to undertake a Scheme of Work, which was designed, using an external review process, to facilitate the establishment of a long term external gas system operator incentive to reduce greenhouse gas emissions. A summary of the Scheme of Work is shown in the following table:

[57] Currently the non traded carbon price published by DECC

Project Number	Project Description	Project Stage	Proposed Improvement	Completion date
1	Pipeline depressurisation - improve current venting calculations including compilation of asset data	Stage 1	System modifications to enable centralised data collection for pipeline depressurisation	31/10/2012
	System modification to enable centralised reporting of station vents	Stage 2	System modification to enable centralised vent reporting of station vents	
2	Enable compressor vent mass calculation to be split into those following an automatic venting trip and others	Stage 1	Survey all NTS compressor sites, except for St Fergus, Warrington and Hatton	31/10/2012
			Survey for St Fergus, Warrington and Hatton	Following Site Works
		Stage 2	Implement split of compressor venting into trip and non-trip vents for all compressor sites except for St Fergus, Warrington and Hatton	31/10/2012
			Survey for St Fergus, Warrington and Hatton	Following Site Works
		Stage 3	Centralised reporting system changes if required	31/10/2012
3 & 4	Improve the current venting calculations for compressor seal leakage venting and Introduce venting calculations for compressor unit isolation valves and unit vent valves*	Stage 1	External assessment to identify sources of leakage. Identify key leakage factors and assess leakage past isolation valves and unit vents and leakage through seals. Calculate assessment of overall leak & review to see whether to progress to stage 2	31/08/2012
		Stage 2	External analysis of a small number of site types using outputs of stage 1 to produce a best practice method for measurement of leakage	
		Stage 3	Evaluate results from stage 2 to develop and implement algorithms and systems to quantify seal and valve leakage for all sites	
5	Study to provide better understanding of gas emissions from the actuation of valves associated with the normal operation of compressors and gas emissions from the actuation of other system valves associated with valve maintenance	Stage 1	Study to provide better understanding of gas emissions from the actuation of valves associated with the normal operation of compressors	31/08/2012
		Stage 2	Study to provide better understanding of emissions from the actuation of other system valves associated with valve maintenance	
N/A	All Project Review: Cost and progress review to assess findings from early stages of projects 3, 4, and 5			31/08/2012

Maintenance and Outage Planning

Overview

531 Maintenance is an essential undertaking as part of our role to keep the network safe, fit for purpose and operating in an efficient and economic manner, in line with various obligations offering benefits to customers and ourselves alike.

532 Stakeholders have asked us to improve flexibility, in particular, how and when we carry out maintenance on the NTS. Stakeholders have also asked us to facilitate out of hours working such as at weekends.

"What Shipper need is the flexibility (and willingness within NG) to change these schedules and the fact that maintenance must be a 7 day a week activity for NG and its contractors."
EON's response to National Grid's consultation, May 2012

"Ideally would prefer there not to be changes to the maintenance period once agreed, except by mutual agreement, we have concerns that NG can schedule 'planned maintenance' at short notice."
Energy-UK's response to National Grid's consultation, May 2012

533 We propose therefore the following approach including the introduction of incentives to promote flexibility where it is valued by our stakeholders and encourage efficient planning on the NTS;

(a) Earlier and better communication of our outage needs to affected parties to enabling better alignment of outages;

(b) A financial incentive to reward good performance where we can reduce the number of our changes made to the Maintenance plan compared to a benchmark based on historic performance;

(c) A financial incentive to use an efficient level of Maintenance Days; and

(d) Ensure all parties are aware that of the services we offer allowing them to pay the incremental costs of working flexibly outside normal working practices or making outages to meet their needs where this is of particular value to them (e.g. taking outages outside normal working hours such as at weekends).

Background

534 In order to facilitate work on the NTS, it is sometimes necessary to take an outage of a part of the network or reduce the flexibility available (e.g. where steady gas flows may be required). This may affect one or more parties connected to the network. Primarily the work that affects our customers is as a result of routine maintenance, asset replacement, pipeline and defect inspections, emergency and faults and work to facilitate investment in the network which may be as a result of a new connection or capacity requirement. These works affect both entry and exit points and are

principally driven by statutory requirements[58] that are delivered through policies and procedures.

535 In working with our customers to plan our system access requirements, we request outage programmes from relevant and impacted industry parties to facilitate alignment of work where feasible to reduce its impact.

536 Under Section L[59] of the UNC, National Grid is required to publish its Maintenance Plan twice each year. The timescales for the production and development of the Maintenance Plan with our customers as set out in the UNC[60] is as follows:

	April Maintenance Programme	October Maintenance Programme
Users provide estimates of their maintenance dates	by 30th November	By 30th June
National Grid publish a draft of the Maintenance Programme	by 1st February	By 1st September
National Grid hold Annual Maintenance Meeting(s)	by 1st March	Users may submit comments on draft Programme until 15th September
National Grid publish the Maintenance Programme	by 1st April	By 1st October

537 Our Maintenance Plan sets out a timetable for the work that is required on the NTS, taking into account affected parties' outage plans where users have given us that information. Following publication of the Maintenance Plan, any requests for changes from our customers or ourselves are assessed to take into account the potential impacts. These may include the impact on other connected parties where there may be coincidence with their notified maintenance; flow restrictions; and previous changes as well as our impacts that may include resource availability, cost implications and any knock on impacts on other work.

538 For exit related planned maintenance, there is a process set out in the UNC that enables us to inform industry parties of intended Maintenance Days where work has an impact on a specific site connected to the NTS. These Maintenance Days are notified in advance of the work to provide industry parties with an opportunity to discuss the timing and impact and for us to respond to any industry requests for further information. In 2011, we were able to accommodate 48% of customer requests to change the notified Maintenance Days.

539 The concept of Maintenance Days only applies to system exit points and each Maintenance Day covers a 24 hour gas day. The number of Maintenance Days for

[58] Including Pipeline Safety Regulations 1996 and Pressure Systems Safety Regulations 2000
[59] Section L of the UNC is available from http://www.gasgovernance.co.uk/TPD.
[60] The timescales in the table above apply to all customers excluding Distribution Networks. The timescale for producing the Maintenance Programme with the Distribution Network is set out Section G of the UNC Offtake Arrangement Document (OAD) – Annex G2. http://www.gasgovernance.co.uk/sites/default/files/03_08_OADG.pdf

system exit points (excluding distribution networks) and the notice period for issuing notices vary and is dependent on what is set out in the Network Exit Agreement (NEXA) or legacy agreement for each site and the UNC. The number of Maintenance Days that can be called at Distribution networks is set out in section 2.5 of the OAD (Offtake Arrangement Document). This states that the NTS can call 8 days per offtake per year for "Flow Relevant Maintenance". This number can be further increased by a maximum aggregate (for all NTS/LDZ Offtakes serving one LDZ) of 10 days.

540 For entry related planned maintenance, there is no provision for Maintenance Days set out in the UNC. Where Network Entry Agreements (NEA's) are in place with the upstream party, they facilitate outage information sharing to enable mutually beneficial co-operation, though there are no binding obligations on either party. Where agreement is not reached, capacity management tools such as capacity buybacks could be used to enable maintenance activities where they impact upon flows. Therefore, the risk associated with managing maintenance at entry is captured within the constraint management incentive.

Developments expected over RIIO-T1 period and TO plan Interactions

541 Over the RIIO-T1 period, an overall increase in the amount of maintenance activities on the NTS is expected. The aim of the proposed incentive is to encourage National Grid to reduce the impact to customers in light of this increase. There are five major types of work that may lead to National Grid calling Maintenance Days due to its impact on customers. These works have different drivers and are expected to change over the forthcoming RIIO-T1 period as follows:

Non – Load Related Work

(a) Routine Maintenance including Routine Valve Operations (RVOs) and metering maintenance.

(b) Asset replacement due to ageing assets and new legislative requirements[61].

(c) In-line inspections (ILIs) of NTS pipelines

(d) Emergency work and fault management including pipeline defect inspection.

Load Related Work

(a) Incremental capacity requirements.

Proposed Approach

542 Our proposal is designed to cover a variety of aspects of maintenance planning and management to deliver value for our customers[62] by improving our communication, and reducing our impact on their operations as outlined below:

[61] An example of this is the requirement to replace many NTS compressors to enable compliance with the Industrial Emissions Directive (IED) – more detail on this is set out in the Managing Risk and Uncertainty annexe of the March Business Plan for the RIIO-T1 period which is available at http://www.talkingnetworkstx.com/gastransmissionplan/our-business-plan.aspx.

(a) Maintenance Plan for the April to March maintenance period to cover 3 years (nearest year in more detail and relatively fixed, other two years to give an indication providing an additional year over UNC requirements;

(b) Incentive to encourage National Grid to minimise changes to the Maintenance plan compared to historic levels;

(c) A service to facilitate customer changes following the notification of the site specific maintenance plan;

(d) An Incentive to keep the absolute levels within a reasonable level of maintenance days or reduce if efficient (penalty for each day above target, benefit for each day below target); and

(e) Increase awareness of the Minor Works Agreement which enables parties to contract for working flexibly outside normal working practices where this is of particular value (e.g. taking outages outside normal working hours such as at weekends).

Maintenance Plan

543 Our stakeholders have asked for more pro-active and better communication around maintenance planning. They wish to see all changes to the plan being mutually agreed and they do not support last minute changes being advised to them by National Grid.

544 We aim to improve communication with our customers by working with them to deliver our maintenance plan through an iterative process, giving affected customers more notice of maintenance that will affect their sites where possible.

545 We propose to information for affected Users for a rolling 3-year period to improve communication with our customers at an earlier stage of maintenance planning to enable better alignment of outages to minimise the impact on their operations. We propose the following level of detail for each of the years in the plan:

	Year ahead (0-12 months)	**Two years ahead** (13 – 24 months)	**Three years ahead** (25 months – 36 months)
Timescales set out for work within plan for affected customers	Specific dates	Indicative quarter of the year	Work identified for the year

546 For customers affected by the maintenance plan, a detailed customer specific maintenance programme will be communicated including:

(a) The type of work and reasons for carrying out this work;

(b) Location of work;

[62] The minutes of the discussion at the Transmission Workgroup (Issues) meeting on 1 May 2012 are available here http://www.gasgovernance.co.uk/sites/default/files/Minutes%20(TX%20Issues)%2001%20May%2012%20v1.pdf and the written responses to our stakeholder consultation are available here: http://www.nationalgrid.com/uk/Gas/soincentives/docs

(c) The impact on the facility (e.g. reduced flow, steady flow or total cessation of flow);

(d) An indication of the dates that the work will take place; and

(e) Duration of work (number of hours or hours within each day).

547 This approach of providing more detailed tailored information for affected customers should enable appropriate information sharing whilst maintaining customer confidentiality.

548 The production of the optimal plans is subject to customers providing us information on their outages.

549 This approach is appropriate because we will provide clear long term visibility of our planned maintenance which will enable earlier feedback on forthcoming outages to allow better alignment of our outages with our stakeholders. This should minimise the impact of outages on their operations and enable more efficient outage planning.

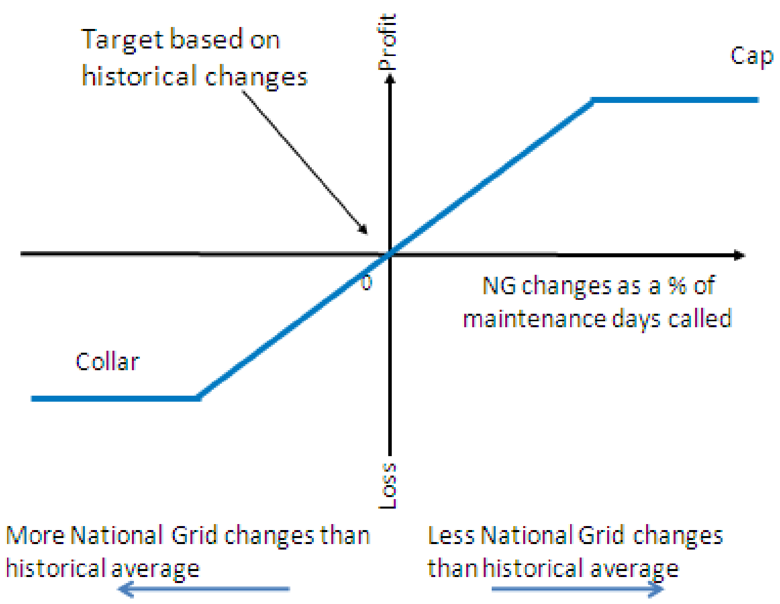
Incentive on Changes to the Maintenance Plan

550 Stakeholders have asked for flexibility to enable maintenance dates to move to align with their maintenance which will move with plant running hours. Four stakeholders have specifically requested incentives to discourage changes in maintenance dates.

551 We therefore propose an incentive to encourage the right behaviours in re-scheduling maintenance that affects directly connected users at exit points from the maintenance programme agreed with industry through the maintenance planning process.

For National Grid initiated changes

552 We propose that the year ahead maintenance plan could form a baseline plan from which any changes are defined. We propose that where we reduce the level of changes that affect directly connected customers compared to historic levels we are rewarded; and penalised if we exceed the base line levels.



Performance measure

553 To measure improvements in the number of changes made in the maintenance period, we propose that we could measure the difference between the number of changes initiated by us and the number of changes made from the current year ahead plan as a percentage for work that affects our customers as shown below:

$$\text{Performance Measure} = \frac{\text{Number of Maintenance days affected by changes initiated by NGG}}{\text{Number of Maintenance Days called}} \times 100\%$$

554 For this purpose, the baseline is the year ahead plan that we propose to publish to affected customers by 15th February for the April to March maintenance period.

Scope

555 The types of change during the maintenance year can generally be categorised into date changes, flow changes and cancellations. We propose that this incentive covers date changes and cancellations.

556 Similarly, only those maintenance activities that directly impact on our customers will be captured. Some maintenance is carried out beyond the April to October maintenance period when Maintenance Days can be called. We propose to include maintenance for the full year within this incentive.

557 Further, we propose that the following activities are within the scope of this incentive because they are planned activities with some level of control over when they occur:

(a) Routine Maintenance (e.g. Routine Valve Operations)

(b) Planned asset replacement & reinforcements (e.g. boiler replacements, work to facilitate the replacement of compressors to enable compliance with IED and incremental capacity requirements)

(c) In-Line Inspections (ILIs)

558 We propose that the following activities are excluded from this incentive because they cannot reasonably be forecast in the baseline maintenance plan at year ahead stage or there is a reduced level of control over the timing of these works because of the reactive nature of this work:

(a) Emergency work and fault management, including pipeline feature inspections; and

(b) Work on behalf of customers (including any work under Minor Works Arrangements).

559 We will consider how to account for customer initiated changes which impact multiple parties and multiple changes relating to a particular maintenance job in this incentive over the next few months as development continues.

Target

560 We propose that the target is based on the historic number of changes made over a 3 year period as shown below;

$$\text{Target (\%)} = \frac{\text{Number of Maintenance Days affected by our changes initiated by NGG over previous 3 years}}{\text{Total number of maintenance days called over 3 years}} \times 100\%$$

561 However, as we are not currently incentivised in this area we currently have limited data. Therefore, for the first year we propose to base the target on 2012/13 data only and for the second incentive year we propose to use the average of 2012/13 and 2013/14 performance. The aim of this interim arrangement to enable the collection of data so that by the maintenance period starting 1st April 2015 the 3 year rolling average can be used to set the target.

Value

562 Through our engagement with stakeholders, we are aware that changes to our maintenance plan can cost hundreds of thousands of pounds particularly when impacting on gas fired generation.

563 In line with feedback from our stakeholders, we propose that the value should be a small proportion of the potential value to our stakeholders.

564 It is proposed that a cap and collar is applied to this new incentive. The value of the cap/collar should be discussed as we develop this incentive further over the next few months. Given the lack of experience under such an incentive and the interaction with customer behaviour, it is important that caps and collars are used.

Length

565 We propose that this incentive is an annual financial incentive within an eight year framework. We propose that the incentive is subject to a full review after 2 years and again at the mid-point 4 years, to ensure that this new incentive is appropriate. At the review stages we would look to refine the incentive to ensure it is aligned to our stakeholders needs.

566 This approach places a value on changes to the plan to encourage us to strive to improve our performance further.

For customer initiated changes

567 For some changes the move may enable a power station to generate or an industrial user to continue its normal operation where we can align our maintenance with their outages.

568 Where customers request changes to the agreed year ahead maintenance plan, and we endeavour to facilitate that request provided that there are no safety implications or adverse effects on other customers. We propose that customers pay the incremental cost of making such changes using a similar approach to the Minor Works Agreement.

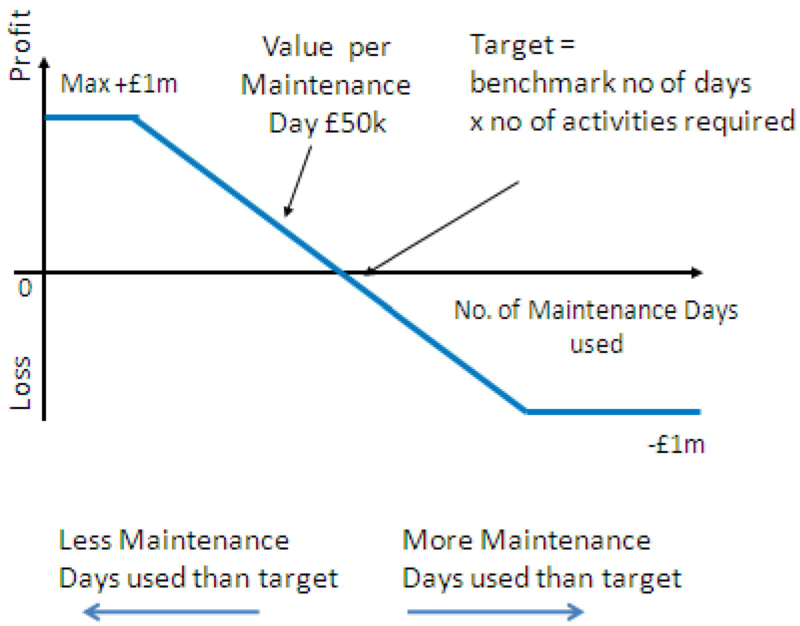
569 This approach is more suited to our customer needs than an incentive, where the cost is shared across industry, because the cost is targeted at customers who require changes to the agreed maintenance plan for their benefit. This cost of this service will include both direct and indirect costs.

Incentive on the Use of Maintenance Days

570 The efficient use of Maintenance Days is also important and our stakeholders value opportunities to reduce its impact.

571 The aim of this incentive is to place a value on the efficient use of Maintenance Days such that if we can work differently to reduce the impact of our activities on our customers then this can be valued.

572 The incentive would reward National Grid for any reduction in the number of maintenance days from a baseline level that reflects the level of work required on the NTS and penalise National Grid for any increase in the number of maintenance days used from the baseline.



Performance Measure

573 To measure our performance in using an efficient level of maintenance days to deliver the work required, we propose to measure the difference between a target number of maintenance days and the number of maintenance days used and as shown below:

Performance Measure = (No of Maintenance Days called - Any Overrun from the number of Maintenance Days called) x No of customers affected

Scope

574 As with the other maintenance proposal, we propose that only those maintenance activities that directly impact on our customers will be captured. Further, we propose that the following activities are within the scope of the incentive to align with where sufficient data is available to set an appropriate benchmark:

(a) Remote Valve Operations; and

(b) In-line inspections (ILIs).

575 We propose that all other activities are excluded from this incentive because data is not readily available currently to confidently build an appropriate benchmark. However we will work to collect more data over the next few years to enable discussion on whether the scope of this incentive could increase if appropriate.

Target and adjusters

576 We consider that the target should be calculated from appropriate benchmarks for each activity, taking into account the level of activity required (e.g. the number and length of ILI runs).

577 The number of ILI runs that we need to carry out changes from year to year and therefore we feel that it would be inappropriate to use a benchmark based on historic activity levels. However, we feel a benchmark for shorter ILI runs and a further benchmark for longer ILI runs could enable a fair target to be calculated as follows:

$$\text{Target number of Maintenance Days an ILI run} = \text{Benchmark for ILI run} \times \text{No of customers affected}$$

578 The maintenance of RVOs is required every year and therefore the workload for this activity is relatively stable. Therefore a simple benchmark could be the level of maintenance days required for RVOs in previous years. This could be adjusted as sites are commissioned, de-commissioned or the number of customers affected by the site works change.

579 We propose that the target for RVO maintenance is fixed for the first two years of this incentive unless adjusted as above.

Value

580 Through our engagement with stakeholders, we are aware that by reducing the impact of our maintenance plan, this can have a large value for stakeholders of particularly when impacting on gas fired generation.

581 In line with feedback from our stakeholders, we propose that the value should be £50k, representing a small proportion of the potential impact.

"The incentive payment to customers cannot compensate for lost generation revenue as this will be too high but it should be higher than the cost of NGG working overtime."
SSE's response to National Grid's consultation, May 2012

582 It is proposed that a cap and collar is applied to this incentive to minimise the risk and reward for National Grid. The value of the cap/collar should be discussed as we develop this incentive further over the next few months. Given the lack of experience under such an incentive and the interaction with customer behaviour, it is important that caps and collars are used.

583 We propose a cap and collar of +/- £1m which is equivalent to 20 days from the target. We propose this level of cap and collar because it is a new incentive and 20

days change from the target would mean a substantial change to current arrangements.

Length

584 We propose that the Use of Maintenance Days Incentive is an annual financial incentive within an eight year framework. We propose that the incentive is subject to a full review after 2 years and again at the mid-point (4 years) to ensure that this new incentive is appropriate and enable further development as we better understand our customers' needs which could include consideration of the incentive scope.

585 As with the change incentive, in fully developing this proposal we will need to consider whether this is best taken forward through an incentive framework or a service.

586 This approach is valuable from the customers' perspective because it encourages us to reduce the impact of our planned work on their activities; resulting in cost savings for industry and to think about how we plan multiple activities such that we are not continually revisiting the same customer.

587 National Grid will aim to achieve a reduction in the number of maintenance days by improving our planning process, innovating where possible and closer working with our customers.

Minor Works Agreements

588 The Minor Works Agreement enables parties to contract specifically for different maintenance approaches. This is something that we already embrace and support through a bilateral contract between NGG and directly connected customers allowing them to pay the incremental costs to NGG for working flexibly outside normal working practices where we are able to accommodate customers' requests.

589 We recognise that awareness levels of this arrangement may not be as high as desired. As part of our review of the plan and communications with affected parties, we will work to improve visibility of these services.

590 The Minor Works Arrangements can cover requests such as:

(a) Customer-initiated requests for NGG work such as the isolation of their supply to facilitate the customer's works.

(b) Customer-initiated requests for us to change our planned maintenance to a non-standard arrangement for example requesting planned maintenance during non-standard hours, such as at a weekend or bank holiday.

591 The incremental cost of this work arrangements are paid by customers in line with the costs incurred. An estimate is given prior to the works and thereafter a reconciliation of actual costs is completed.

592 We propose that these revenues are treated as an excluded service, such that the revenues for this work can be treated as incremental revenues against the incremental costs that we incur.

Delivering Benefits for the Consumer

593 The approach described above enables the regulatory arrangements to drive the right behaviours and will provide value to the industry. These incentives will deliver the flexibility and visibility that our customers have strongly emphasised in various consultations to enable more effective and aligned maintenance processes.

Capacity Scaleback

Background

594 Under the anticipated arrangements for the RIIO-T1 period, there are two types of capacity that we can scale back, daily Interruptible Entry Capacity and daily Off-Peak Exit Capacity. These types of capacity can be scaled back if operationally required for constraint management purposes.

595 Interruptible Daily Entry Capacity[63] is released for the gas day D in a pay as bid auction allocated between 13:00 and 15:00 day ahead (D-1). The volume of capacity made available in the auction consists of two components, the Use It Or Lose It (UIOLI) volume defined in accordance with a UNC methodology and an additional discretionary volume that we may choose to offer.

596 Off-Peak Daily Exit Capacity[64] is a new product due to be implemented in October 2012 as part of Exit Reform. It will be released for gas day D in a pay as bid auction where the allocation period commences at 15:00 D-1. There are a number of rules determining the volume that can be released, including a UIOLI component similar to that on Entry and an obligation to release up to the maximum metering capability, or some other physically limiting factor at the exit point. If bids exceed the available amount, discretionary off-peak capacity may also be released.

597 Currently the revenue from interruptible capacity is included in the constraint management scheme and for the RIIO-T1 period we are proposing that this is extended to include Off-Peak Daily Exit Capacity revenues. The constraint management scheme already provides an incentive for us to maximise the availability of system capacity whilst minimising the cost of constraints management.

598 Under current arrangements we can scale back capacity rights[65], without financial penalty, and restore rights within day, without financial reward. There are therefore currently no financial incentives on us to:

(a) delay scaling back

(b) minimise scale back; or

(c) reverse scale back

599 As a result, scaling back of non firm capacity provides a ‘free option’ without performance measurements or financial incentives.

[63] Further details on the industry framework for Interruptible Entry Capacity are available in Section B2.5 of the UNC available at http://www.gasgovernance.co.uk/TPD.

[64] Further details on the industry framework for Off-Peak Exit Capacity are available in Section B3.6 of the UNC available at http://www.gasgovernance.co.uk/TPD.

[65] Further details on the industry framework for Constraint management including Scale backs are available in Section B2.8 of the UNC available at http://www.gasgovernance.co.uk/TPD.

600 On many occasions Interruptible Daily Entry capacity sells at a zero price or very close to it, with the exception of periods of high firm capacity utilisation at Easington in 2008 and 2009.

601 The following table summarises information regarding Interruptible Daily Entry Capacity sales over the last three years, and the extent and value of our scale back actions[66].

	2009/10	2010/11	2011/12
Average capacity released (GWh/d)	2,066	2,360	2,367
Weighted Average Price (p/kWh)	0.000059	0.000037	0.000027
Total revenue (£k)	441	316	232
Scale back (%)	0.1%	0.4%	0.7%
Revenue associated with scaled back capacity (£)[67]	£0.00	£11.92	£0.00

602 It illustrates that the total revenue from the sale of Interruptible Daily Entry Capacity ranges between £200 and £450 thousand pounds per year. The extent to which we actually scale back capacity is very low, significantly less than 1% by volume.

603 The market's value of the capacity that was actually scaled back over the last 3 years, based upon the price at which it was sold, is less than £12 (twelve pounds).

604 The market's value for Off Peak Daily Exit capacity is currently unknown but anticipated to be small given the non firm rights commercial rights implied.

Developments expected over RIIO-T1 period and TO plan Interactions

605 Our outlook suggests considerable uncertainty in the market's demands for, and use of capacity over the RIIO-T1 period.

606 The probability of there being occasions when the supply and demand profiles required by customers exceed those that can be safely accommodated from a system pressure or linepack perspective is likely to increase dramatically.

607 As a result we believe there is potential for greater intervention to manage constraints through the RIIO-T1 period. This could lead to greater reliance on the scaling backing of capacity for constraint management purposes, which could lead to users placing more value on the non firm products.

Proposed Approach

66 As Off-Peak Daily Exit Capacity products are due for implementation in October 2012, the analysis excludes these elements.

67 The revenue associated with scaleback is subject to the actual price paid for the capacity that has been scaled back.

608 Stakeholder feedback at the capacity and connections stakeholder event on 1st May was not supportive of a new incentive in this area, which may reflect the relative infrequency of scale backs in the current environment and our underlying economic and efficient obligations:

SSE: "Is not supportive of such an incentive. Maximising available and a UNC code change can be raised to implement new policy."
Energy UK: "At the current time, scale back is used frequently so we are unsure about the materiality of this."

609 On the basis of our stakeholders views, the market's current value for non firm capacity, and the financial value of the capacity which has been scaled back to date, we do not propose to implement a financial incentive at this stage.

610 As an alternative we propose to monitor and report annually to customers on the financial outturn value of capacity that has been scaled back and resumes the potential for a financial incentive in this area in the future.

Information Provision

Overview

611 We provide operational information to the market both in the form of data available through our website to inform the market (e.g. current flows onto the NTS) and information on the overall market and how it may develop into the future through industry consultation processes that lead to production of the Ten Year Statement (TYS). We are currently incentivised to publish specific operational information on the NGG website[68].

612 We are proposing a twofold approach for information provision. Firstly, change the information provision incentive from financial to reputational given existing performance levels. Secondly, undertake industry consultation on our future information provision strategies to allow us to better understand our customer requirements, system performance, data provision methods etc.

613 Stakeholders have said how important the provision of information is to them and their organisations. A number of stakeholders support a reputational incentive in this area providing it is accompanied by agreed metrics and publication to ensure any changes in performance have an impact on our reputation. One stakeholder believed a financial incentive is more appropriate given the importance of this information.

Background

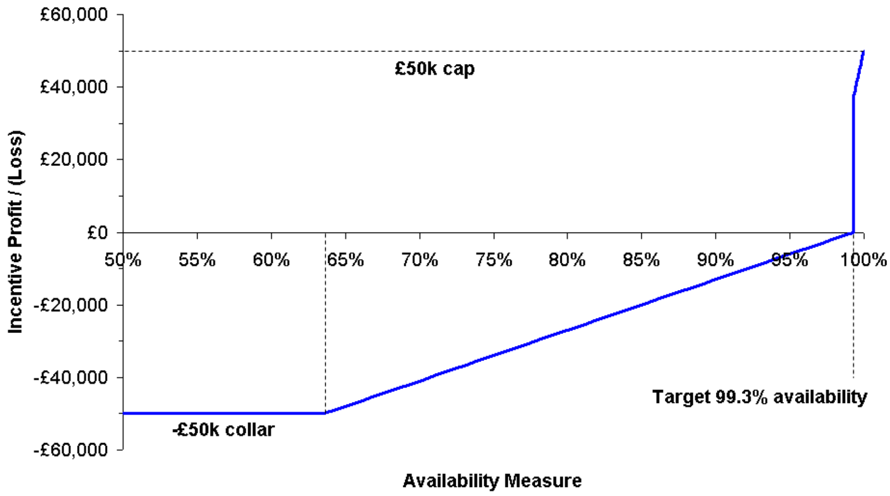
614 An incentive scheme for data publication has been in place for 6 years, ensuring the provision of critically obligated within-day data is delivered to extremely high standards of system availability and timeliness. The incentive focused on two aspects, the availability of the MIPI (Market Information Provision Initiative) system which provides this data, and the timeliness of specified data items - seen as critical to efficient market operation (demand, supply and linepack forecasts). The original incentive, introduced in October 2006, had the objective of improving performance, providing a revenue stream to support system investment and to deliver the required performance levels.

615 Since April 2008, the value of the scheme has been reduced to £100k to reflect achievements in performance, whilst continuing to provide an enduring incentive for us to maintain this level of performance.

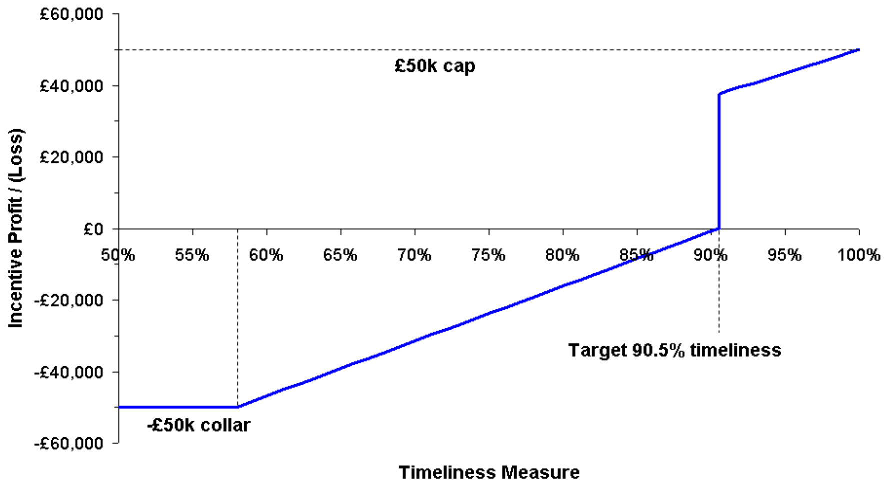
616 See details of the current scheme in the charts below:

2012/13 NTS Data Availability Incentive

[68] Please refer to the supporting information document that is available at: www.nationalgrid.com/uk/gas/soincentives/supportinginfo/ for more information on the current scheme.



2012/13 NTS Data Timeliness Incentive



"Focus should be given to data being updated quickly and systems being available at times of system stress. i.e. during times of GBAs."
SSE response to April 2012 SO Consultation

Developments expected over RIIO-T1 period and TO plan Interactions

617 In developing the strategy for information provision to meet customer requirements across the RIIO-T1 period, we will need to take into account a number of significant factors, including:

(a) the continually increasing utilisation of the data;

(b) the evolving UK regime requirements; and

(c) the impacts of EU legislation

618 Significant increases in utilisation of market data over the period is also evident, with data requests from customers growing around 10 fold over the period to more than 1 billion hits per annum in 2011/12. Consequently, such growth has impacted the

system and a number of tactical initiatives are underway to ensure performance and availability.

619 We expect this increase in demand for data will continue to grow throughout the RIIO-T1 period. Whilst this is a positive confirmation of the value of the information provided to our users, it may create a significant delivery challenge in respect of our systems and how we may need to develop them.

620 As the operation of the NTS and the market in the UK evolves as a result of increasing gas imports, and the impact of decarbonisation, customers are likely to need different and, potentially more frequent, data to support efficient operation. The 'real time flow data' published at a 2 minute resolution, is currently the most utilised data provided. Any requirement for more frequent data publication would require a fundamental review of the way this data is managed and delivered to customers.

621 Finally, the introduction of further EU Regulations and Directives on energy market integrity and transparency, including the development and implementation of the European Network Codes mandated under the Energy Infrastructure 3rd package, will drive further information provision requirements as well as potentially changing the way this information is made available.

622 The majority of European developments include elements of information provision/transparency as well as developing requirements for consistency in data publication, processes and systems. The standardisation of data formats and platforms could significantly alter the way in which data is provided to customers.

623 It will be important to understand whether the current delivery methodologies and processes are appropriate to meet requirements going forward or whether new strategies and approaches are required.

Proposed Approach

624 All stakeholders told us how important the provision of information is to them and their organisations. They said the data needs to be quickly updated and the website has to have a high level of availability. One stakeholder did raise concerns about a recent drop off in performance in terms of timeliness and availability.

625 Whilst most stakeholders supported a reputational incentive, as long at the metrics were agreed with stakeholders and regularly published, one stakeholder said the information was so important to our customers that a financial or penalty incentive was more appropriate.

626 We believe that the approach for the RIIO-T1 period should comprise two distinct elements described below.

A reputational incentive

627 We propose that the financial incentive is removed and replaced with a reputational incentive based upon the existing performance levels and the majority of stakeholders agree, as long as any change in performance does have an impact on our reputation.

“*Given this high level of reliability and timeliness we would support the move to a reputational incentive*”
EDF’s response to National Grid’s consultation, May 2012

“*A reconsideration on incentivisation/penalties in this area should be undertaken by Ofgem, given the recent trend change in the way NG’s customers are using its website.*”
EON’s response to National Grid’s consultation, May 2012

628 In light of the incentive becoming reputational only, we propose a licence condition to report to Ofgem and industry on our website performance on a monthly basis, providing information on the following areas;

(a) The overall availability of the system: This will comprise of the same parameters as the current scheme in place including keeping three key screens (prevailing view, data item explorer and report explorer) available with a monthly target of 99.30% of availability with as little downtime as possible

(b) The timeliness of the critical market data published: This covers how timely our updates are in respect of publishing four key data items: (Predicted Closing Line Pack, National Forecast Flow, National Physical Flow, and Forecast NTS Throughput) when available in a timely manner. The monthly target benchmark for timeliness is 90.50% of updated within 10 minutes of the start of the hour

(c) The utilisation of the site by customers; and

(d) Any significant events that have occurred within the period

629 This approach will ensure transparency by allowing market participants to monitor and review our performance, compared with current performance.

Further consultation

630 Secondly, we are proposing to engage with stakeholders later this year in respect of information provision strategy. This engagement will initially take the form of a written consultation document which will allow us to better understand any changing requirements from customers related to, system performance, data provision methods, utilisation levels and the interaction with EU platforms amongst other things.

631 Following feedback from this engagement process, we would then expect to propose an overall information provision strategy reflecting stakeholder requirements. At this stage, it may be appropriate to also review the data publication incentive arrangements given wider industry developments.

Stakeholder views

632 Stakeholders wish to have quick and easy access to reliable data which is of significant value to them, whilst recognising that our data provision has improved over recent years. Many stakeholders now view such information provision as a routine requirement rather than an action to be financially incentivised.

633 Some stakeholders have highlighted their concerns in the performance of timeliness and availability in recent months. This issue has been due to the current MIPI platform being utilised at a level far in excess of that anticipated when it was designed, raising concerns for the RIIO-T1 period.

Delivering Benefits for the Consumer

634 The financial incentives to date been successful in ensuring information provision has been developed in line with customer expectations. Our information provision services are highly valued by the UK gas market. However, with the expected increasing levels of demand, development of new technologies and increasing interaction with Europe, it is essential that the data provision capability is developed further in line with customer expectations and to meet our obligations.

635 A reputational incentive which includes regular reporting will ensure that there is a focus on the performance of the current system, and the proposed stakeholder engagement to develop future information strategy should ensure customer expectations are understood and managed.

Provision of Enhanced Services for NTS Users

Overview

636 As we move through the RIIO-T1 period we anticipate that users, for a variety of reasons, will increasingly look to operate flexibly. The principle drivers being the requirement to maximise opportunities in the UK and EU gas markets, and support the operation of CCGT plants in the electricity market as a balancing fuel for renewable generation.

637 Flexible operation for users (both up to, and beyond, their contractual parameters) has been readily available over the last few years. As the requirement for enhanced services continues to grow however, we will reach a level where such freedom of operation will become increasingly difficult to deliver for all that require it.

638 When this point is reached, it would seem sensible for the provision of enhanced services to be operated through a commercial mechanism, within an associated incentive scheme to align benefits between users and ourselves. This is particularly important where user's requirements for flexible operation exceed their defined contractual parameters and thus the obligations on the SO to deliver.

639 This approach would allow the SO to make the appropriate value based decisions between the potential value of enhanced services and the potential costs and risks that could be incurred in other areas, such as compressor fuel usage, capacity constraint management, etc, through the release of these services. As such we are not proposing specific incentives at this stage, but recognise we might need to revisit this over the RIIO-T1 period.

640 Stakeholders have told us they do not support an incentive in this area at this time, with a number saying parties should bring forward modification proposals for the new services they wish to develop via the existing governance arrangements. They added; using the existing governance routes will ensure transparency and engagement with stakeholders.

Background

641 Currently, we accept requests for additional services where we can accommodate them whilst maintaining the safe and efficient operation of the network. This includes the facilitation of higher ramp rates or accepting shorter notice periods than provided for by existing contractual provisions. As user requirements for such enhanced services continue to evolve and grow it will become increasingly challenging. It is likely that our ability to accommodate the total requirement for user flexibility during a particular period will reduce. In such circumstances a mechanism to ensure equitability in the provision of the level of service that is available to users will be required. This could therefore lead to users recognising these benefits as services that have a commercial value.

642 We have already been approached by customers in relation to additional services and products that could be offered, which they would be willing to pay for, in order to meet their future needs. As user requirements change, it would seem sensible to review the contractual obligations, the products available to users, and the need for new incentives that better align the needs of system users for such enhanced

services and the ability of the SO to make appropriate value and risk based decisions.

643 We do not anticipate that these services would be required from 1st April 2013. Rather that they would be developed with the industry during the RIIO-T1 period. Implementation may need to be carried out in association with the development of new commercial products, although alternative approaches may be equally viable and detailed industry consultation will be required to find the most appropriate solution.

Developments expected over RIIO-T1 period and TO plan Interactions

644 We anticipate that across the RIIO-T1 period there will be a number of drivers on users to operate more flexibly within and between gas days including:

(a) Gas power stations providing services to enable the use of intermittent renewable generation (e.g. generating during periods of low wind generation);

(b) Gas power stations taking an increasing share of electricity demand profiling as other flexible generation, i.e. coal, is closed due to environmental legislation;

(c) Distribution networks requiring increased offtake flexibility to support gas holder closures, and connection of gas generation and non conventional gas supplies into distribution networks;

(d) Interconnector flows reflecting increased commercial harmonisation across Europe;

(e) Interconnector flows supporting EU wide gas requirements for managing intermittent renewable generation; and

(f) Storage sites providing fast turnaround services to support shipper balancing (in response to power station intermittency etc).

645 Whilst we currently endeavour to provide the services that users require on a best endeavours basis. Going forward some users may require greater level of certainty around enhanced services to meet other commitments, such as ability to operate flexibly within the electricity market.

646 Without incentives and / or other products the SO would not be obliged to not provide services beyond contractual parameters at times when the release of these services could lead to balancing costs elsewhere. This could potentially lead to both increased costs for consumers and limitations on the ability for the electricity market to meet its decarbonisation targets.

647 This issue was identified within our RIIO-T1 price control submission with respect to network flexibility and it would seem appropriate to link the development of incentive arrangements in this area with the processes identified within the network flexibility uncertainty mechanism.

648 We would anticipate that this mechanism could be triggered either through analysis of the published network flexibility indicators which we publish periodically or through

experience of increased customer impact (through say, balancing costs incurred) caused by flexibility issues.

Stakeholder views

649 Some stakeholders support the development of new products in this area. When discussed at the UNC Transmission Workgroup meeting[69], however, many stakeholders were concerned about the practicalities and others questioned whether or not there is a genuine need.

650 Stakeholders were asked if incentives should be developed in this area to include for example, shorter notice periods or higher ramp rates may be appropriate in the future[70]. The overall impression was that it is too early to warrant a financial incentive, with a number of stakeholders saying the current governance arrangements are adequate in terms of parties introducing proposals for new services. However, some recognise that there may be benefits in us identifying commercial options available to NTS connected points to review and modify their ramp rates.

651 Stakeholder's views were also sought on the potential interactions between and incentive and the network flexibility uncertainty mechanism.

652 Stakeholders responded with mixed views. Generally the position is not supportive of an incentive at present with one stakeholder outlining the risk of duplicating funding for the same service. One acknowledged that the case for investment to manage network flexibility has yet to be demonstrated and will be managed via an uncertainty mechanism.

Proposed Approach

653 We are mindful of the interaction between an incentive in this area and the network flexibility uncertainty mechanism included in our RIIO-T1 business plan. Network flexibility is the term we have used to identify the additional operational capability required for the NTS to be able to accommodate the changing flow patterns required by users into the future. If industry supports changes to the existing framework, such as through the network flexibility uncertainty mechanism, any solutions may use new or existing Rules, Tools and Assets as outlined in the 'Managing Risk and Uncertainty' Annex to the March RIIO-T1 Business Plan[71] .

There was general support for the use of the uncertainty mechanism, given the lack of evidence at this stage about network flows. Despite this, stakeholders also raised a number of queries about how the uncertainty mechanism would actually be implemented.
RIIO-T1 Talking Networks Stage three workshop Brunswick report, 9th November 2011

[69] The minutes of the Transmission Workgroup (Issues) meeting on Tuesday 31 January 2012 are available here: http://www.gasgovernance.co.uk/sites/default/files/Minutes%20tx%20issues%2031%20Jan%2012%20v1.pdf
[70]Stakeholder consultation notes are available here: http://www.nationalgrid.com/uk/Gas/soincentives/IndustryWork/
[71] Network Flexibility Managing Risk and Uncertainty Annexe is available at http://www.nationalgrid.com/NR/rdonlyres/99622FDF-8B76-4388-BAA1-4AD17B8B50D5/52239/2012_NGG_managing_risk_and_uncertainty_redactedsecure.pdf

654 The network flexibility uncertainty mechanism will only be considered if operational trends or customer requirements are identified that would otherwise lead to material increased risks or costs. Following identification, Asset, Rules and Tools solutions would be considered and explored with industry.

655 The trigger for the network flexibility uncertainty mechanism will be a proposal to Ofgem reflecting direct feedback from primary and relevant stakeholders, following a consultation process.

656 For Rules and Tools solutions, it may be appropriate to consider introducing products and/or financial incentives on the SO for these types of services, such as shorter notice periods and higher ramp rates, as and when they are valued by customers.

657 At this stage we are not proposing an incentive, however, in the future there are a number of viable options for an incentive to be developed, for example:

(a) Parties buy an enhanced service product (via an auction process potentially, for a zone or location on the system, in advance of the period, which we would be obliged to deliver as if it were contractual arrangement, and then if we had to withdraw flexibility we would pay a fee (either pre-agreed or via a bid process)'

(b) Parties request enhanced services through the Offtake Profile Notification (OPN) process as now, and if this is greater than contractual levels and we accept it we take revenue via a defined mechanism, and as with (a) pay a fee if we subsequently need to withdraw it; or

(c) Parties pay us a fixed fee up front to cover provision of enhanced services for the year, and this is reduced based upon the level of services delivered to meet user requirements.

Delivering Benefits for the Consumer

658 By not proposing an incentive at this stage provides the industry with the time to develop and consider new services / products that are valued by our customers, which could be incentivised at a later date in order to drive value for consumers.

Customer Satisfaction

Overview

659 Customer and Stakeholder Satisfaction is an indicator of how well we deliver against our customers' and stakeholders' expectations of the vital services we provide. To recognise the importance of customer and stakeholder satisfaction in today's society, we have proposed a financial incentive based on a satisfaction survey and a discretionary reward for stakeholder engagement within our March RIIO-T1 business plan.

660 Ofgem have proposed that the financial incentive associated with the survey has a value of up to +/- 1% of annual revenue, and that the discretionary reward has a maximum reward of 0.5% of annual revenue[72].

661 We propose that these incentives cover both the SO and TO aspects of our role to align with customers' experience of how we operate as integrated provider of transmission services.

Background

662 In 2009, we recognised the need to implement a new customer strategy on the back of the evolving energy industry and changes to our customer base; as such we introduced a formal survey in 2009 to help identify potential improvements to our customer service levels. We have been working hard since then to improve our customer service and satisfaction strategies and have launched our customer commitment[73]; which sets out what customers can expect in the delivery of our services.

When asked about customer service standards, stakeholders agree that National Grid staff are experts at the 'day job' - the networks are run well and there is a high level of technical expertise. In terms of customer service, there was recognition that improvements have been made but there is still some way to go. Some attendees suggested that National Grid could still be more proactive in dealing with its customers.

RIIO-T1 Stage one workshop, Brunswick report, 23rd November 2010

663 Ofgem has proposed an incentive package to encourage the network companies' behaviour in relation to monitoring performance against outputs and driving improved customer and stakeholder satisfaction scores and improved levels of stakeholder engagement. We have developed customer satisfaction surveys that will be used to set the level of performance for this output, which align with the work we have undertaken in recent years.

Developments expected over RIIO-T1 period and TO plan Interactions

[72] The average electricity TO revenue over the 8 year RIIO-T1 period is £1,811m.

[73] National Grid: Our commitment to UK Transmission customers

664 Within the Outputs[74] section of our March RIIO-T1 business plan, we have proposed a financial incentive relating to customer satisfaction.

665 The proposed financial incentive mechanism has the following features:

(a) The first aspect is based on the results of an annual customer and stakeholder satisfaction survey. The survey will reward companies that can demonstrate improvements in customer and stakeholder satisfaction over the RIIO-T1 period; and

(b) The second aspect will be a discretionary reward, which will incentivise performance where we can demonstrate that our effective stakeholder engagement has led to positive outcomes for stakeholders

666 The graph and table below illustrate our proposals, with the blue line on the graph representing the uncapped performance and the red line the capped performance.

	Max Gain		Max Loss	
	Survey score	Max gain	Survey score	Max loss
Uncapped performance	9.00	+1.0%	4.80	-1.0%
Capped performance	7.95	+0.5%	5.85	-0.5%

667 The customer satisfaction incentive is a symmetrical incentive scheme using the absolute customer and stakeholder satisfaction score (measured on a scale of 1 to 10, with 10 being the best score), with a target (break-even point) set to our current customer satisfaction score of 6.9, and maximum gain with a score of 9.0. Since this incentive is the first of its kind and we have limited previous experience of a customer survey, we propose a degree of protection against windfall gains or losses. Our

[74] National Grid's outputs section from the Business Plan: Outputs | Transmission: Electricity | National Grid

proposals[75], which will be finalised through further discussion with Ofgem, accommodate the full (uncapped) +/- 1% of annual revenue range subject to meeting pre-defined criteria which may comprise quantitative and/or qualitative measures. If these criteria are not satisfied, then a restricted (capped) +/- 0.5% of annual revenue range will be applied.

668 We are currently developing candidate quantitative and/or qualitative measure with Ofgem, and the candidate measures include:

(a) Number of complaints received in the year

(b) Standards of service being met/missed

(c) Response scores to particular questions within the survey (for example, responses to the questions relating to our customer commitment)

(d) Percentage of responses less than / equal to four out of 10; and

(e) Percentage of responses greater than / equal to eight out of 10

Proposed Approach

669 The survey to be carried out with our stakeholders will cover their views on SO and TO activities that we carry out. We propose a single customer satisfaction incentive to reflect the combined nature of our business. To separate out SO and TO customer satisfaction incentives would add complexity with limited material benefit.

670 The proposed incentive encourages us to consider the overall impact of our actions on our stakeholders and aligns with the commitments we have already made to our customers and stakeholders. Through our customer commitment program we have published our actions in response to the feedback we have received through customer surveys.

671 Consequently, greater focus and improved customer service should improve the efficiency of our operations and deliver long term benefits and potential cost savings for the consumer.

[75] Further information on our proposals set out in the Outputs annexe of our March RIIO-T1 TO Business Plan http://www.nationalgrid.com/NR/rdonlyres/91BBEC0F-50BB-4826-B008-11B5129CC037/52184/2012_NGG_Outputs_redactedsecure.pdf

Risk and Uncertainty

Overview

672 Under the RIIO framework, the price control settlement will be based on forecasts of output requirements, demand for network services over time, the cost of delivery (including input prices) and financing costs. The nature of many of the gas incentive schemes, whereby many elements are agreed upfront, will mean that the certainty associated with forecasts vastly reduces over time. As a result, there is a risk that:

(a) the revenues raised from consumers could be higher or lower than necessary to cover the costs of providing system operation (SO) services, with consumers paying more or less for services than was necessary

(b) the outputs that are set at the time of the control may turn out to be insufficient or inappropriate

673 Therefore, the main sources of uncertainty surrounding the SO incentives relate to the delivery of outputs, the input prices, volumes of activity required and changes to the political and regulatory background. As part of the RIIO framework, Ofgem has proposed three main options to deal with this uncertainty, namely:

(a) risk sharing through the efficiency incentive rate

(b) uncertainty mechanisms; and

(c) A mid-period review of the output requirements.

674 As part of the specific incentive design scheme, we have included a number of mechanisms that allow for incentive longevity, including volatility adjusters, price adjustment mechanisms and volume adjusters. Risk has been further managed through the scheme parameters in terms of scheme length, sharing factors and caps / collars.

675 Irrespective of this however, an element of residual risk remains. We have therefore undertaken an exercise to better understand the financial risks that we will face from our SO external activities over the forthcoming RIIO price control period and how the risk that we face from our system operation role determines the return on equity we require. As a result, an additional premium of £3.3m per annum is required to cover the residual risk. We have not, as part of this submission, specified a means by which this premium should be remunerated.

Risk Analysis Process

676 In order to be able to assess the risks that may impact the achievement of our business objectives, it is essential for us to be able to understand them. This knowledge will enhance the management's ability to make better decisions, deliver strategic and operational performance targets, protect corporate reputation, drive shareholder value and ensure value for money for customers and other stakeholders.

677 In assessing our risk management approach we have been guided by the Turnbull Guidance (Revised Turnbull Guidance, para 4, October 2005):

'A company's objectives, its internal organisation and the environment in which it operates are continually evolving and, as a result, the risks (operational, financial, compliance and other) it faces are continually changing. A sound system of internal control therefore depends on a thorough and regular evaluation of the nature and extent of the risks to which the company is exposed. Since profits are, in part, the reward for successful risk-taking in business, the purpose of internal control is to help manage and control risk appropriately rather than to eliminate it.'

678 In response to Turnbull and other best practice guidance, we use two separate but complementary processes: Risk Management and Compliance Management. These have been designed primarily as management tools but they also:

(a) contribute toward a better informed decision making process to help businesses achieve their objectives

(b) strengthen and streamline the system of internal control

(c) support and reinforce an open, proactive and 'risk and compliance aware' work culture

(d) closely align to business planning, performance management, and internal audit planning

(e) contribute toward a relevant and cost effective insurance programme

(f) facilitate the identification of opportunities (upside) as well as risks (downside)

(g) help protect reputation and shareholder value

(h) enable National Grid to clearly demonstrate good corporate governance to its stakeholders

(i) ensure compliance with the listing requirements of the London Stock Exchange.

679 The wider price control review process provides an opportunity for us to review our risk appetite. The regulatory arrangements that will be put in place for the RIIO-T1 period will inevitably depart from those in place today under the TPCR4 framework. The changes have the potential to fundamentally alter the risks to which the business is exposed and, therefore, the risks that customers and other stakeholders might be asked to bear. Given the potential impact of these changes, it is right for us to revisit the fundamental risk drivers of the business, in order to understand the nature of these risks and their potential materiality.

680 In certain instances it might be suitable for us to bear more risk going forward into RIIO than it was previously, provided that this increase in risk is reflected in the setting of SO incentive schemes. In addition, the prospect of regulatory framework change means that risk will increase in a number of areas where there is little we can do to manage it. This creates the need for new uncertainty mechanisms, or the enhancement of existing uncertainty mechanisms.

681 There are some risks that are completely (or largely) beyond our control, or where the only available actions are prohibitively expensive and clearly would not provide value. In such cases it is not clear that it is in consumers' best interests for us to bear those risks (and act as an insurer earning a premium) or whether the consequence of

these uncertainties would be more efficiently passed through to customers. We have based our analysis on the principle that risks should fall on those parties best able to manage them.

682 To support our risk analysis work for RIIO-T1, we have developed a risk model to better understand the relationship between risks, uncertainty mechanisms and our financial performance. The model uses probabilistic techniques to evaluate the impact on financial performance for the RIIO-T1 price control which builds on the analysis undertaken for the Transmission Operator submission. This provides a basis for assessing the impact of System Operator risks.

Key Drivers of Risk and Uncertainty

683 As described in greater detail within the 'System Operator Role: Now and into the future' section of this document, the operating environment is set to fundamentally change over the RIIO-T1 period, principally driven by the changes to the location and nature of UK gas supplies, a need to meet the UK's 2020 environmental targets and the introduction of IED. This shift towards a lower carbon economy and its corresponding affect on gas supply and demand backgrounds, transmission network design and market frameworks manifest itself in fundamentally increasing the operational risk that we face as the SO.

684 These changes can be broadly captured within three broad categories:

(a) Price risk: The price at which we can buy and sell gas is principally driven by fuel input costs. The input price for fuel is determined by international markets and will continue to be affected by the maturing price of carbon. With the churn in the generation portfolio during the RIIO-T1 period and an increasing reliance on the importation of primary fuel import sources we will face considerable price uncertainty in undertaking our SO responsibilities.

(b) Volume risk: As the residual balancer, we face uncertainty around the volume of actions that we will need to take to drive the overall market to balance. This is driven by various factors that are directly or indirectly out with our control such as demand and supply mismatches and the volume of constraints on the system that we need to resolve. Changes to the generation portfolio and the way industry parties manage demand, coupled with greater interconnectedness to Europe, will culminate in increasing the variability of the volume of actions we need to undertake.

(c) Political / Regulatory risk: In order to meet carbon reduction targets, both on a UK and European wide level, considerable uncertainty is introduced through changes being introduced to market frameworks. For example reviews such as Electricity Market Reform, IED, and European Network Code developments, all carry considerable risk to the way that we operate. Political risk also gives rise to increasing uncertainty. A clear example of this risk was the decision by Germany to close its Nuclear plants by 2022 and immediately closing several of its oldest plants following the Fukushima disaster.

685 Whilst not an exhaustive list, these types of risks need to be factored into the potential total range of external costs that we may incur in carrying out our SO role. The remainder of this section describes how we have tried to factor these risks into our initial risk modelling and how we will require uncertainty mechanisms to cover specific risks

Risk Modelling

686 In designing the scheme and exploring what the appropriate boundary is between who should manage the risk (either us or the consumer), we have modelled the uncertainties and the potential ranges of outcome. We have concentrated on the incentive mechanisms that have potentially the highest impact, buybacks/constraint management and shrinkage. We have modelled the risks associated with shrinkage and constraint management based on historical trends and cost data.

687 From the historical, data we have set a distribution around each of the components of costs and targets for these schemes. We have used this to performed Monte-Carlo simulation to provide a range of incentive performance outcomes. We have modelled outcomes over the RIIO-T1 period with and without caps and collars in order to determine the underlying risk range.

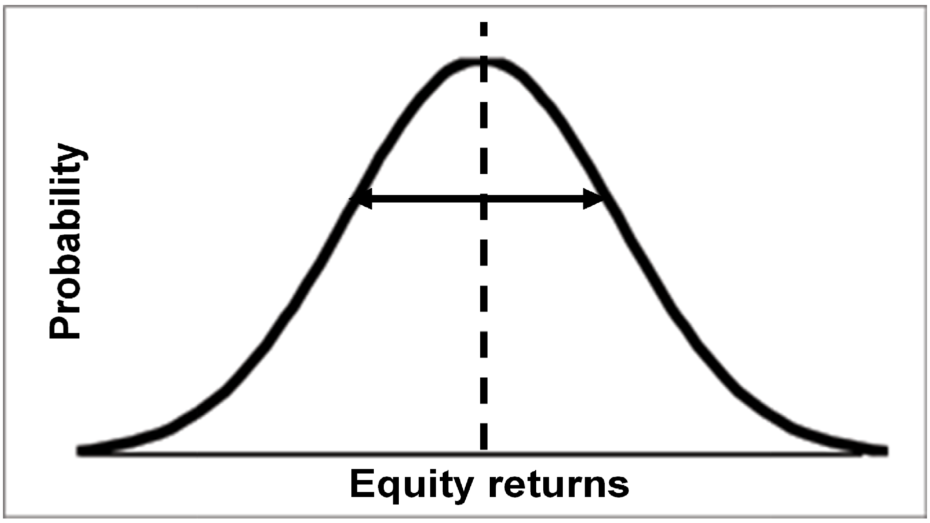
Financeability

688 The consideration of the risks that we face within our SO business need to be appropriately accounted for. A distinction needs to be made between reward for performance and remuneration for undertaking risk. The incentive outcome provides an opportunity for us to be rewarded for good performance and penalised for bad performance. It does not provide remuneration for undertaking and managing risks.

689 We are proposing therefore that a premium for undertaking and managing the risk associated with the SO incentives is included within the incentive package.

690 Risk can be defined as the variation in asset returns around expected asset returns, i.e. it is a measure of volatility. The Sharpe ratio can be used to compare two portfolios with different degrees of volatility to assess whether the risk-return trade off is appropriate. Within our March submission, we investigated the relationship between the required return on equity and variation in equity returns. We propose to use the same approach to determine the appropriate premium for the risks posed by the various SO incentive schemes.

691 In translating the risk to an equity return, our modelling considered the dispersion in equity returns for different incentivisation methods described above (with or without caps/collars). The narrower the dispersion in equity returns, the lower the justified premium over risk free rates. Dispersion is illustrated in the diagram below.



692 The gas SO does not have a sufficiently large balance sheet to finance or absorb the risk associated with the levels of cash flow requirement described above. These risks would effectively be underwritten by the wider NGG TO balance sheet, and thus we have derived the return that would be appropriate as an increment to the required TO return using the Sharpe ratio. Assuming the risk free rate to be constant, the risk/return balance is maintained if:

$$\frac{Return_{TO} - Return_{Risk\ free}}{\sigma_{TO}} = \frac{Return_{TO+SO} - Return_{Risk\ free}}{\sigma_{TO+SO}}$$

Where σ represents the standard deviation of returns

693 Our March submission identified the appropriate return on equity for TO business, and it's associated risk profile, as being 7.5%. We have performed additional modelling to add the SO risk to establish the incremental impact. The table below summarises the impact on the required post-tax cost of equity with the application of the Sharpe ratio for the Shrinkage and Constraint Management incentive schemes. The rows in bold represent our proposals as described within this document, but for completeness, we have included other computations with different cap/collar assumptions.

Shrinkage - incremental change in required return			
	Stand deviation of pre-tax return on equity	Implied post tax cost of equity	Incremental return
Base case (RIIO TO submission)	0.7119%	7.50%	-
50% sharing factor & no caps/collars	0.7190 %	7.55%	0.050%
50% sharing factor & +/-£10m cap/collar	**0.7182%**	**7.54%**	**0.044%**

Constraint management - incremental change in required return			
Constraint management scheme considered	Standard deviation of pre-tax return on equity	Implied post tax cost of equity	Implied additional post tax cost of equity to base case
Base case (RIIO TO submission)	0.6475%	7.50%	-

Add in Constraint Management scheme with 50% sharing factors and no cap/collar, target equal to expected performance measure	0.6595%	7.59%	0.092%
As above, but a +/-£20m cap/collar	**0.6570%**	**7.57%**	**0.073%**
As above, but a +/-£15m cap/collar	0.6560%	7.57%	0.065%
As above, but a +/-£48m cap/collar	0.6591%	7.59%	0.89%
As above, but a cap of +£15.5m and a collar of -£11.5m collar	0.6550%	7.56%	0.58%

694 As per our proposals, an increment of 117 basis points (for both shrinkage and constraint management schemes) to the identified TO equity return is required to ensure a commensurate reward for undertaking the residual SO risk. If caps/collars and variable sharing factors were to be removed, then the requirement would increase to 142 basis points.

695 The gas SO RAV is very small and thus it is not possible to credibly set a rate of return that could be applied to the RAV. As a result the potential premium has been calculated using the NGG TO RAV[76].

696 The implied post tax cost of equity figures calculated in the table above have been used to derive an appropriate annual risk premium, by multiplying them by the assumed equity portion of the RAV. The results are shown in the following table:

Scheme considered	Resultant annual risk premium (£m)
Sharing factors & caps/collars	3.3
50% sharing factor & no caps/collars	4.0

697 The premium required with the application of caps and collars as proposed is equivalent to 3.3m per annum. The introduction of a scheme premised on 50% sharing factors without the application of caps/collar would result in premium of around £4.0m per annum.

Sense Check

698 As a sense check to the proposed risk premium, we have sought to identify the level of risk premium investors might expect if the SO were a stand-alone business, given the risk they would face underwriting the SO incentive schemes. A standalone SO business carrying the risk proposed would need a balance sheet to absorb that risk. A balance sheet size of 3 years worth of losses appears reasonable.

699 The 95% confidence interval for annual scheme performance shows an average lower limit of around £32m for a sharing factor only scheme and £28m for a scheme

[76] The average opening RAV for the NGG TO over the RIIO-T1 period is £6,263m. Assuming a gearing level of 55%, this implies that the equity portion of this is £2,818m.

with caps/collars. Under a scheme without caps/collars the expected loss over three years amounts to £96m (£32m x 3) and £84m for a scheme with caps/collars. The table below shows the expected equity financing requirements using varying equity returns.

	Annual Scheme Performance- 95% confidence interval (lower limit)								
	2014 £m	2015 £m	2016 £m	2017 £m	2018 £m	2019 £m	2020 £m	2021 £m	Average over RIIO-T1 period £m
50% sharing factor & proposed caps/collars	30	30	30	30	23	25	30	28	**28**
50% sharing factor	33	35	36	34	25	27	34	30	**32**

700 Given the scale of risks, such a business would need to be wholly equity funded. Equally, such a business would be expected to have a cost of equity higher than that of the TO business, predicated by the fact that the SO business balance sheet does not have the capability to absorb these risks.

701 We have used a range of equity return to illustrate the potential risk premium requirements to attract equity investors. The table below shows the expected equity financing requirements using varying equity returns.

Risk premium based on 3 years of average losses		
Rate of equity return	**50% sharing factor (£m)**	**Variable sharing factor & caps/collars (£m)**
7.5%	7.1	6.4
10%	**9.5**	**8.5**
12%	11.4	10.2

702 Compared to the proposed 7.5% return on equity for our NGG TO business, the SO as a stand-alone business would be substantially more risky and thus would command a correspondingly higher rate of return. Investors in a stand-alone SO would expect a return of at least 10%, giving an expected annual risk premium in the range £8.5m and £11.4m from the table above, dependant on the incentive scheme parameters.

703 We have proposed a risk premium of £3.3m per annum (in 2009/10 prices) which is lower than what would be required for a stand-alone SO business due to the benefits of risk diversification across our wide transmission business.

Funding the Additional Risk Premium

704 Whilst the return on equity approach for the SO business on a standalone basis is inappropriate (due to the size of the SO RAV), the reward required to cover residual risk could be managed in one of three ways:

(a) Provide for a net positive expected incentive outcome in the SO control,

(b) An explicit administration fee, or

(c) Additional return via the TO control.

705 We do not believe that providing additional return via the TO control itself is an appropriate solution as this could result in a cross-subsidy between different classes of User. The means by which the additional premium is remunerated will need careful consideration when determining the overall SO package of incentives.

Uncertainty Mechanisms

706 We have already mentioned that a number of uncertainty mechanisms will be required in respect of the gas SO incentive package. The GB electricity market is facing a period of significant change and uncertainty with the development of a sustainable, low carbon electricity sector and greater market integration with Europe. Setting a robust and effective long-term incentive scheme against this level of uncertainty is going to be extremely difficult, and can only be achieved if they are supported by appropriate uncertainty mechanisms.

707 The proposed incentive schemes set out in this submission have been designed to deal with a degree of uncertainty using mechanisms that adjust the incentive target based on factors outside our control. Caps and collars also are proposed to protect against windfall gains or losses resulting from issues not captured by these mechanisms. We also propose to retain the concept of Income Adjusting Events (IAEs) to deal with major events outside our control.

708 In addition, we propose the inclusion of the following political / regulatory uncertainty mechanisms as part of the overall package. These should take the form of a re-opener should substantive change occur in these areas. This will allow for further consideration as to whether the overall SO incentive package remains appropriate in a changing world.

The facilitation of European energy markets

709 The convergence of EU energy markets under the Energy Infrastructure 3rd Package will undoubtedly drive the need for changes to the GB regulatory regime. It is, however, unclear at this stage as to the likely nature of those changes, and the consequential impacts on the UNC. We expect significant changes to GB codes and amendments to our Licence, which in most cases will require changes to business processes, information provision requirements, IT systems and even network assets.

710 In terms of the incentive schemes described here, European led changes have the potential to be widespread and may require a more fundamental review of the schemes. The possible harmonisation of calorific values across Europe could for example have a consequential impact on shrinkage, through a variation to existing CV values, or a requirement for an additional blending role, currently outside of the scheme. Similarly, the interoperability and balancing rules contained with the European Codes are likely to increase the uncertainty surrounding end of day balance, therefore altering the nature of our residual balancing role.

Changes to the GB regime

711 Similarly, the prospect of further GB led changes has the potential to impact on incentive design. Over the RIIO-T1 period, a number of framework changes are likely to materialise, including;

(a) Further modifications to develop NTS capacity and connection processes,

(b) The contractualisation of dynamic parameters at entry points as NTS flexibility becomes increasingly constrained,

(c) Electricity Market Reform and its subsequent impact for the NTS,

(d) Greater SO to SO interaction across electricity and gas, and

(e) The Ofgem led Significant Code Review (SCR) and DECC review of UK security of supply.

712 All have the potential to impact on the SO incentive schemes detailed within this document, with particular impacts on constraint management, residual balancing, demand forecasting and capacity delivery. Indeed a number of our stakeholders have already expressed concerns regarding the yet as quantified impact of regulatory reform such as the EMR. As such, they are supportive of the SO schemes being reviewed at the appropriate time.

Network Flexibility

713 Flexible operation for users (both up to, and beyond, their contractual parameters) has been readily available over the last few years. As the requirement for enhanced services continues to grow however, we will reach a level where such freedom of operation will become increasingly difficult to deliver for all that require it.

714 When this point is reached, it would seem sensible for the provision of enhanced services to be operated through a commercial mechanism, within an associated incentive scheme to align benefits between users and National Grid. This is particularly important where user's requirements for flexible operation exceed their defined contractual parameters and thus the obligations on the system operator to deliver.

715 We are mindful of the interaction between an incentive in this area and mechanisms included within our RIIO-T1 business plan. Network flexibility is the term we have used to identify the additional operational capability required for the NTS to be able to accommodate the changing flow patterns required by users into the future. If industry supports changes to the existing framework, such as through the network flexibility uncertainty mechanism, any solutions may use new or existing Rules, Tools and Assets. It may therefore be necessary to introduce new incentive arrangements or at the very least modify the existing constraint management incentive .

Industrial Emissions Directive (IED)

716 Adjustment for uncertainty in the scope and therefore the number of compressors affected by the Industrial Emissions Directive (IED) that sets out emissions limits for industrial combustion plant and drives replacement of compressors to enable compliance. IED has the potential to impact on shrinkage in terms of the compressor fuel usage, and also to the greenhouse gas incentive in terms of the venting characteristics of compressors.

Stakeholder Engagement

Overview

717 We have engaged with our stakeholders, sought their views on the proposed SO incentives for the RIIO-T1 period and used their views to help shape our SO incentives business plan. This section describes the engagement we have undertaken, provides a summary of stakeholders' views on the incentives and how they have been incorporated into our plan, and then outlines the next steps we will be taking with our stakeholders as we work together to develop the SO incentive regime for April 2013 and beyond.

Engagement Process and Incorporation into our plan

718 We have engaged with stakeholders, discussed the proposed incentives, heard and understood their views and used them to help shape our SO incentives business plan. Our engagement has covered a number of specific activities, including:

(a) Two SO incentives stakeholder workshop held in May 2012

Topics covered in UNC Transmission Workgroup 1st May 2012
• Connection Offers
• Capacity delivery
• Constraint management
• Maintenance and outage planning
• Capacity scale back
• Enhanced services for NTS users

Topics covered in Stakeholder Workshop 3rd May 2012
• Demand forecasting
• Residual balancing
• NTS shrinkage

(b) Publication of a stakeholder consultation document[77] outlining our initial thoughts on the SO incentives. This consultation gave stakeholders the opportunity to provide us with their written comments on our initial thoughts ahead of our submissions to Ofgem.

719 During our TO RIIO-T1 stakeholder engagement we have discussed and gathered stakeholders' views on a number of key areas relating to the SO incentives, both through workshops and written consultations. We have used the outcomes from this

[77] http://www.nationalgrid.com/uk/Gas/soincentives/IndustryWork/

engagement to also inform our SO business plan. The topics covered included connections, capacity and innovation.

720 We have also drawn on the stakeholder responses Ofgem received to its 'System Operator (SO) Incentive Schemes from 2013: Principles and Policy[78]' consultation which was published in January 2012. We have been mindful of the feedback we have received from stakeholders regarding the number of consultations being conducted in the industry and the draw on their time. Taking this into account we consider it was relevant to use the consultation responses published by Ofgem in the development of our plans.

721 In addition, we have engaged with our stakeholders throughout the current TPCR4 price control period as part of the regular reviews of the SO incentives. Many of the comments made by stakeholders during these reviews have been echoed in both the latest Ofgem consultation and the stakeholder workshops we held in May 2012.

722 Our engagement process has been open and inclusive with all our consultation material and reports published on our Talking Networks[79] and NGG[80] websites. The minutes from the 1st May meeting are available on the Joint Office of Gas Transporters website[81].

723 We acknowledge stakeholder feedback that the consultation process carried out in April and May 2012 was tight in terms of timescale and would like to thank all our stakeholders for their support and input.

724 Stakeholders have provided us with a variety of views regarding the SO incentives. In a number of areas they are in general agreement to maintain the current incentive as it is, such as support for the current Residual Balancing incentive whereas in other areas, such as having an incentive to provide enhanced services, there was no support for our proposals.

725 A number of stakeholders have said they wish to see more details regarding the incentives before they can be fully supportive of the proposals. In addition, concerns have been raised regarding how the details will be developed and agreed in time for April 2013. For more detailed commentary of our stakeholder views, please see Appendix 8.

Next steps

726 We will continue to work with our stakeholders in the development of the SO incentives for the RIIO-T1 period. Specifically, we will be engaging further in the following areas:

(a) Delivering connections and capacity: In June 2012, further discussions will be held at the UNC Transmission Working Group (Issues).

(b) Information Provision: Industry consultation is planned later this year.

---

78 http://www.ofgem.gov.uk/Pages/MoreInformation.aspx?docid=277&refer=Markets/WhlMkts/EffSystemOps/SystOpIncent

79 http://www.talkingnetworkstx.com/consultation-and-engagement.aspx

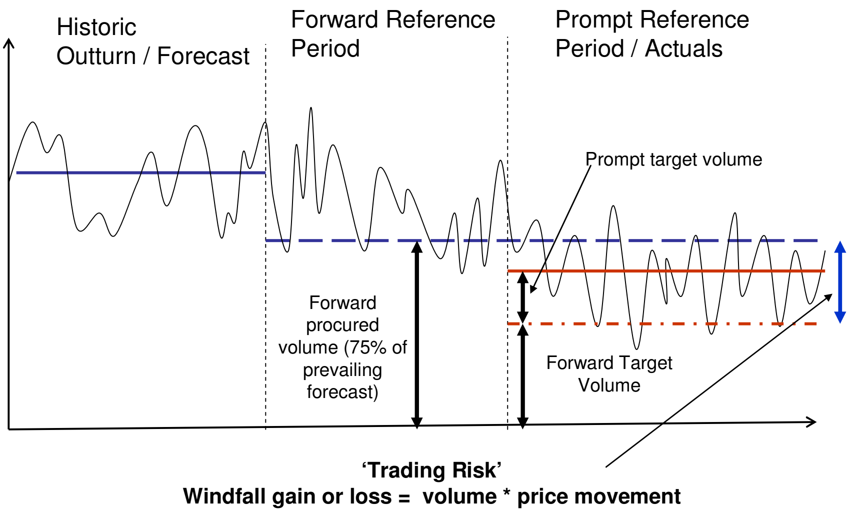
80 http://www.nationalgrid.com/uk/Gas/soincentives/IndustryWork/

81 www.gasgoverance.co.uk/tx/010512

(c) Operating Margins: Further developments will be considered following the completion of the OM review (this is expected in 2013).

Appendix 1: Trading Risk

1.1 The combination of forward reference prices and ex-post target energy requirements can lead to a trading risk. As shown below, at the start of a forward price reference period trades are made against the prevailing (best available) forecast of forward target amounts (in this case 75% of prevailing forecast). Closer to delivery, as forecasts accuracy improves the forward target requirement is adjusted. The price difference represents a windfall gain or loss.



1.2 The extent of risk is a function of energy forecast uncertainty, the trading horizon (forward price reference period to ex-post energy target setting), and price movement over the time horizon.

1.3 Where we have control or influence over the forecast uncertainty, this may be an appropriate risk to manage. We do not, however, consider this the case for

(a) UAG energy;

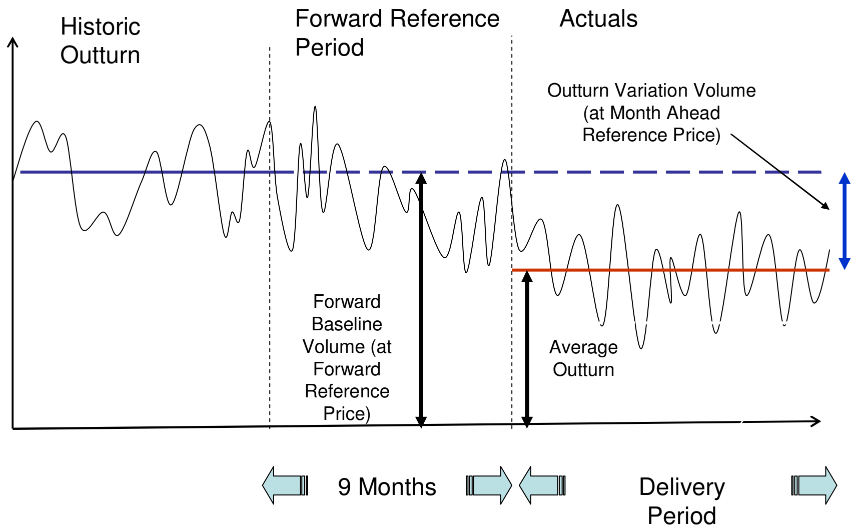
(b) CFU adjustment, where we cannot be expected to forecast the exact supply-demand balance (by all driver supply points) over extended forecast horizon; and

(c) Exceptional CVS arising from identified CV Shrinkage risks associated with Ross, Dyfrynn Clydach and Cowpen Bewley where there are no economic and efficient mitigating actions that National Grid can take as the System Operator to manage the risk.

1.4 Referencing shrinkage energy to shorter-term forward contracts could significantly reduce this but would increase customer's exposure to the volatility of prompt prices.

1.5 Customers have expressed concern over their risk premium related to the predictability of shrinkage costs.

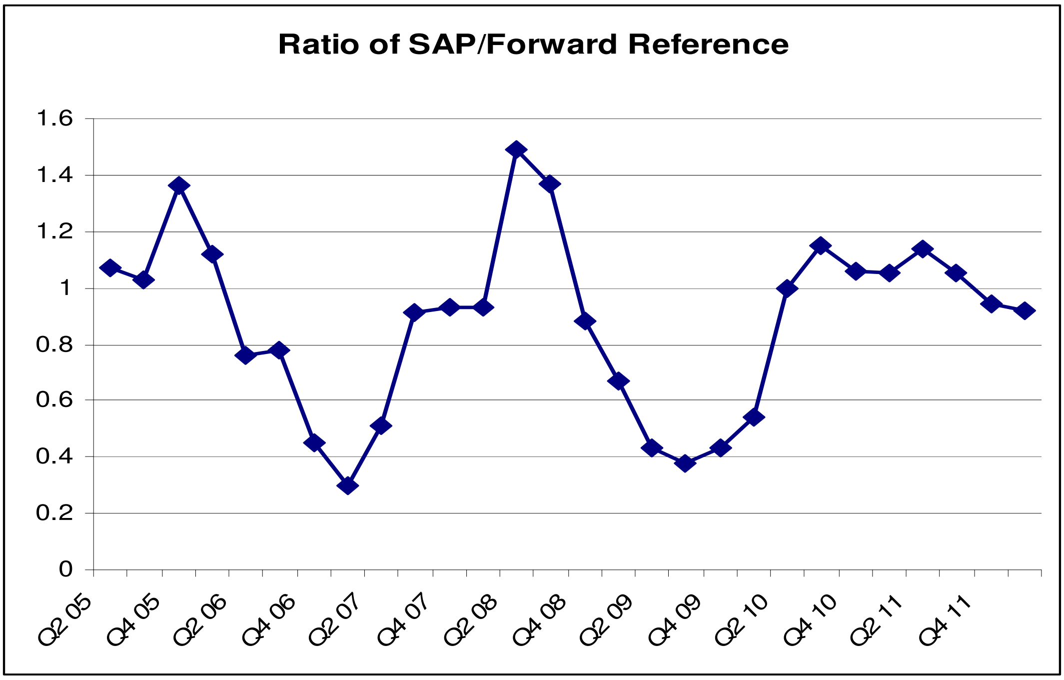
1.6 An alternative approach defines fixed forward reference energy requirements at the start of the forward price reference period and a shorter term reference for unmanageable uncertainties (retrospective adjustments) from that fixed forward reference level as illustrated in the diagram below:



Appendix 2: 'Tranche Buying' Reference Periods

2.1 Since the introduction of the shrinkage incentive schemes, our stakeholders have supported the use of 'Tranche' forward buying in order to spread risk given the relative price stability of the forwards markets.

2.2 The chart below highlights how, since the second quarter of 2005, SAP prices have outturned between 50% higher and 70% lower than current methodology reference prices. Reliance on short term prompt markets to satisfy significant daily requirements creates significant risk, and instability for Users' costs.



2.3 Agreeing a Price Reference Period (PRP) defines a price risk management strategy acceptable to customers. All other things being equal, this means target costs reflect the underlying markets' price and that neutral incentive performance is achieved.

2.4 It is the identification and management of risks and opportunities that allow movement away from the neutral position and hence deliver cost savings to customers.

2.5 The existing Gas Cost Reference Price (GCRP) methodology has been established for a number of years and drives us to adopt forward procurement and risk management strategies. These have delivered significant savings over market prices, whilst protecting customers from the volatility of prompt market prices.

2.6 The current Electricity Cost Reference Price (ECRP) methodology is fundamentally the same as GCRP, but with shorter-term forward procurement based on quarter prices a month ahead of delivery. This bias towards prompt prices was considered appropriate given the uncertainty in electric drive commissioning. It was proposed to seek further alignment between ECRP and GCRP methodologies once greater certainty was established over the programme to install electric compressors.

Options for calculating the Price Reference Period (PRP)

2.7 Three options have been considered. All seek to deal with a number of practical / operational issues including:

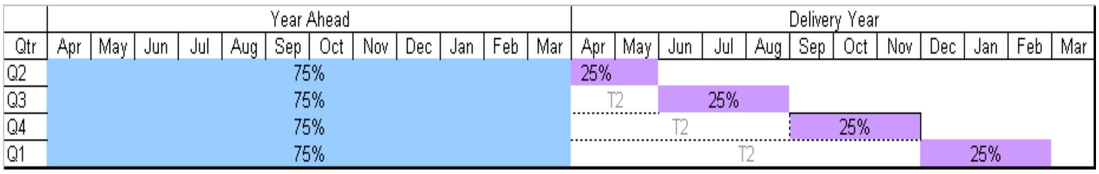
(d) The significant material trading risk evident as a result inherent variability of the NTS shrinkage components;

(e) The limited liquidity in the quarterly forwards markets at year ahead;

(f) The lack of published benchmark prices for electricity market over the same time horizons; and

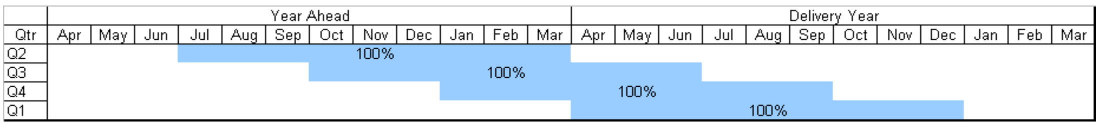
(g) The lack of continual market price data (denoted T2 below) used to define the reference price.

2.8 All options are in line with the current GCRP methodology, as shown below, and assume calculation of PRP quarterly by applying a 75% weighting to the average price of quarter contracts over each day in the year ahead, and a 25% weighting to the average price of a monthly contract over each day in the preceding month.



Option 1: (Recommended approach)

2.9 This option proposes to use a nine month price reference period.



2.10 The advantages of such an approach include:

(h) The maintenance of a balance of forwards and prompt reference prices which creates a 'fair' market benchmark price for customers;

(i) The reduction of hindsight trading risk through the use of shorter forecast horizons;

(j) Improved liquidity of forward contracts; and

(k) The existence of consistent and continual quarterly prices, i.e. no gaps in price reference periods.

Option 2:

2.11 The second option would be use a seasonal price reference period, with a rolling twelve month ahead of the season in question.

	Year Ahead												Delivery Year											
Qtr	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar
Q2																								
Q3														T2										
Q4																								
Q1																				T2				

2.12 This would generate greater liquidity since such contracts are more liquid at the year ahead stage.

Option 3:

2.13 The third option would be to use a three month rolling price reference period, i.e. three months ahead of the quarter in question.

	Year Ahead												Delivery Year											
Qtr	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar
Q2											100%													
Q3														100%										
Q4																	100%							
Q1																				100%				

2.14 Such an approach would allow for:

(a) Increasing focus on prompt reference prices, with 33% weighting to month ahead of delivery quarter;

(b) Reduced hindsight trading risk given the shorter forecast horizon;

(c) Increased liquidity of forward contracts; and

(d) More consistent and reliable quarterly prices.

2.15 We consider that the reference price methodology must be consistent with the minimisation of trading risk. We therefore propose a 9 month rolling price reference period (option 1 above).

Appendix 3: Swing Cost

3.1 The reference price methodologies are used to provide a cost reference for a reasonable procurement strategy assuming the energy requirements are flat. However efficient cost management and cash out price mitigation necessitates that we tailor the flat purchases to the volatile outturn energy requirements.

3.2 For gas load this will be a daily variance, and for electricity load this will be a half-hourly variance. The profile of these variances are referred to as swing, generating a swing cost.

3.3 This incremental swing cost has been provided for by uplifting the GCRP and ECRP respectively; unit price uplifts derived from target cost divided by forecast energy requirement.

3.4 Over the RIIO-T1 period, this may generate material windfall gain or loss if outturn energy requirements are significantly different to forecast, for example the potential for significant variance in UAG levels can create a material over or under recovery of swing cost.

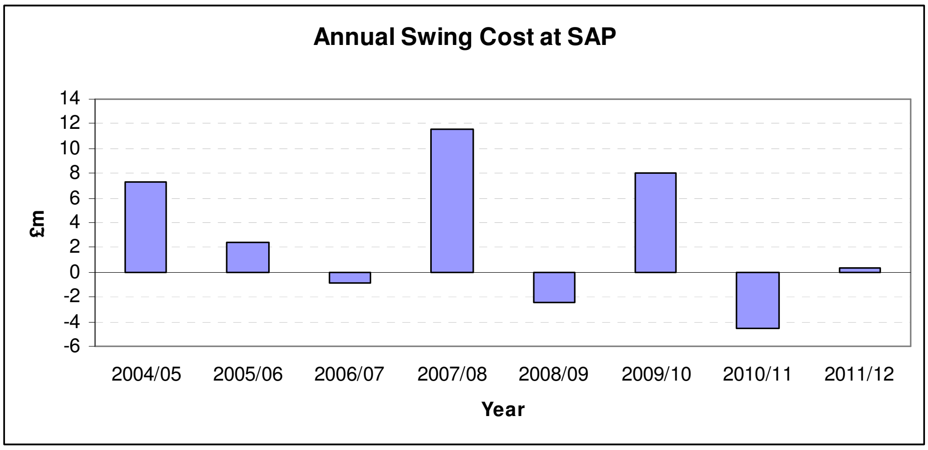
3.5 To mitigate the risk associated with energy forecasts we consider application of a fixed cost allowance is appropriate rather than unit price. There still remains uncertainty in annual swing cost target. Appropriate targets for the RIIO-T1 period are discussed below.

Gas Swing Cost

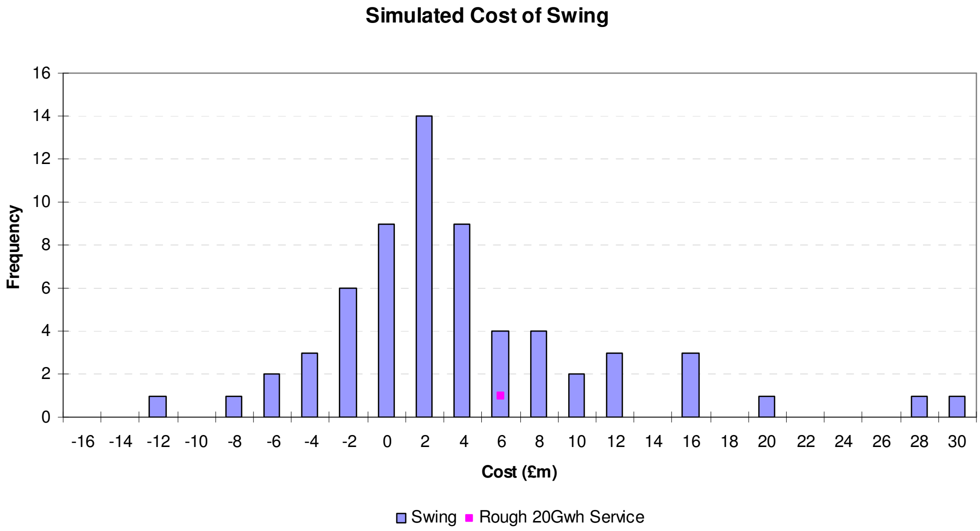
3.6 In relation to shrinkage gas requirements, there are two approaches to benchmark the swing cost, either ex-ante through use of a storage service (as now) or ex-post prompt market prices. These approaches are discussed below.

Approach 1: Gas swing cost using ex-post benchmark

3.7 Under this option the target cost of managing swing would vary according to the profile of outturn market prices and daily swing requirements. An assessment of historic swing cost is shown below based on net cost of daily Swing Volumes multiplied by System Average Price (SAP).



3.8 The chart shows a high year on year variability due to favourable and unfavourable combinations of volume and price profiles. An assessment of cost uncertainty over the RIIO-T1 period is shown below based on all scenarios of historic profiles – the price and energy requirements are independent, looking forward any combination is just as likely and outside our control. The ex-ante cost assessment is also shown for reference.



3.9 This cost distribution quantifies the uncertainty of the ex-post swing cost and risk borne by customers. This assessment could understate risk over the RIIO-T1 period if;

(a) market price differentials change relative to this historic analysis; or

(b) swing patterns change as a result of changing gas compressor loads or operations following commissioning of electric drive compressors; or

(c) As a result of requirements for increased network flexibility.

3.10 With an ex-post target our exposure would be limited to trading performance against daily reference price for outturn swing volumes. The absence of an energy target may raise concerns over the efficiency of outturn swing requirements or the potential ‘trade off’ with other operational incentives that value system flexibility.

Approach 2: Gas swing cost using an ex-ante benchmark

3.11 Customers typically favour the cost stability offered by ex-ante management of swing requirements. This approach sees customers paying the outturn swing cost, with any variance from benchmark cost captured through incentive sharing factors. This ex-ante benchmark maintains an energy requirements efficiency measure absent in an ex-post benchmark approach. The current market cost of this service, shown in the cost distribution above, quantifies the value (and cost) of the insurance premium relative ex-post cost.

3.12 The cost of storage has been used as a readily available market benchmark to manage swing requirements. Based on average historic swing requirements and a ‘single cycle’ storage service, i.e., inject negative swings on 188 days and withdraw to meet positive swing requirements on 177 days, then based on services available from the Rough storage facility:

(a) 19.7 GWh of Standard Bundled Units (SBU – a fixed ratio of withdrawal:injection:space capacities) would be required to service the maximum swing withdrawal, or

(b) 47.4 GWh SBU would be required to service the maximum swing injection – a far more costly option

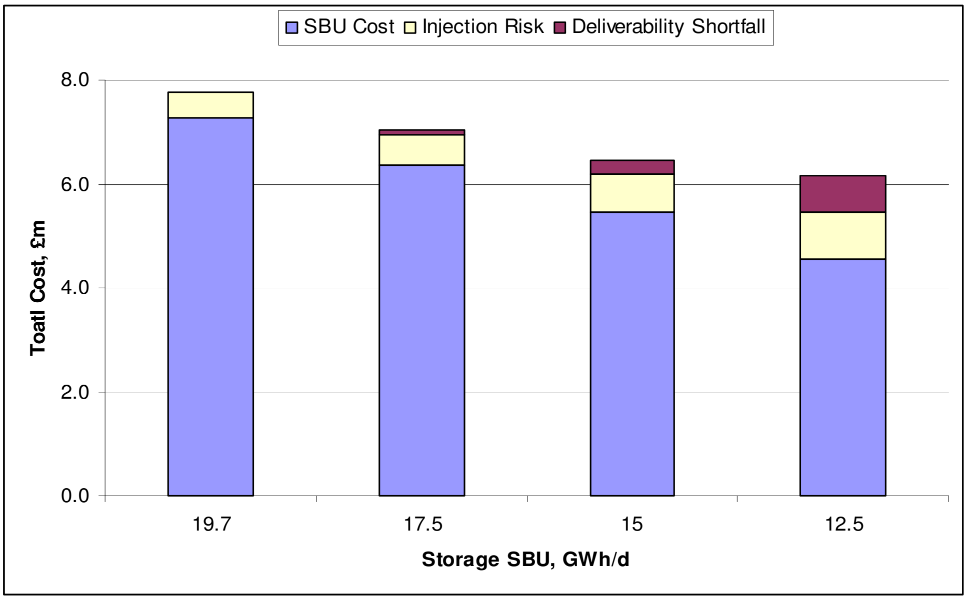
3.13 The current market cost for a Rough service to meet peak swing withdrawal requirements is £7.2m. However based on the Rough standard bundled unit (SBU), this is an injection limited service that would require some market sells of excess negative swing on days with injection shortfall, and market buys on days with spare injection capacity. This additional prompt management of swing across days is equivalent to 15%, by volume, of the historic ex-post swing management cost.

3.14 The £7.2m benchmark cost is based on average peak deliverability requirement. A cost allowance based on peak deliverability requirements has been challenged by Of gem questioning the efficient level of storage booking (or insurance premium). Reducing the booking (to say average deliverability requirements) will:

(a) Increase the injection capacity risk discussed above; and

(b) Create a deliverability shortfall requiring incremental market buy actions to balance the Shrinkage Provider account.

3.15 The total cost of an ex-ante option is shown below, valuing the injection capacity risk pro-rata by volume of the mean ex-post management cost and the deliverability shortfall cost at gas market prices. Given the uncertainty in market costs for injection risk and deliverability shortfall, a swing cost benchmark based on peak deliverability is considered most appropriate.

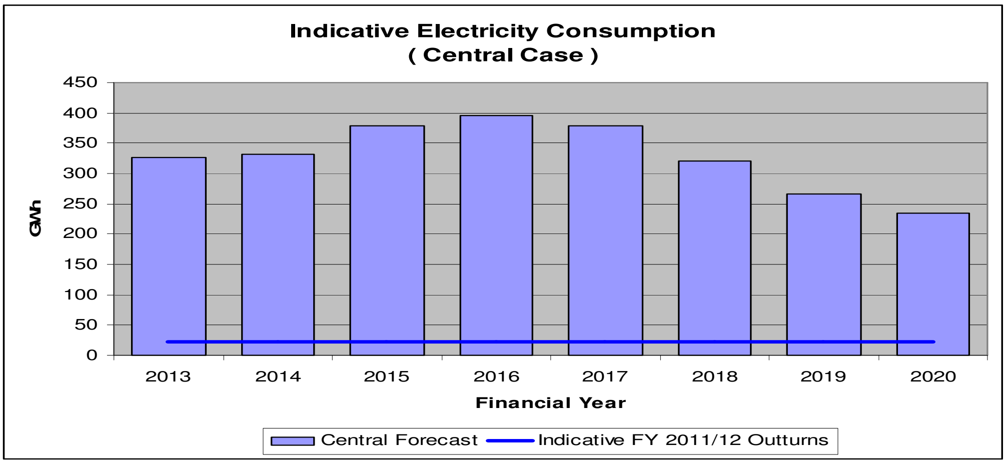


3.16 Market prices for Rough services and gas commodity have been variable and remain uncertain over the RIIO-T1 period, thus an ex-ante benchmark for swing cost would require a periodic update based on a defined methodology statement.

3.17 Additionally the swing cost methodology would require a periodic review to ensure average historic swing profiles and the Rough SBU service, if still available, remains appropriate benchmarks. Given these uncertainties National Grid consider a 2 year review appropriate.

Electricity Swing Cost

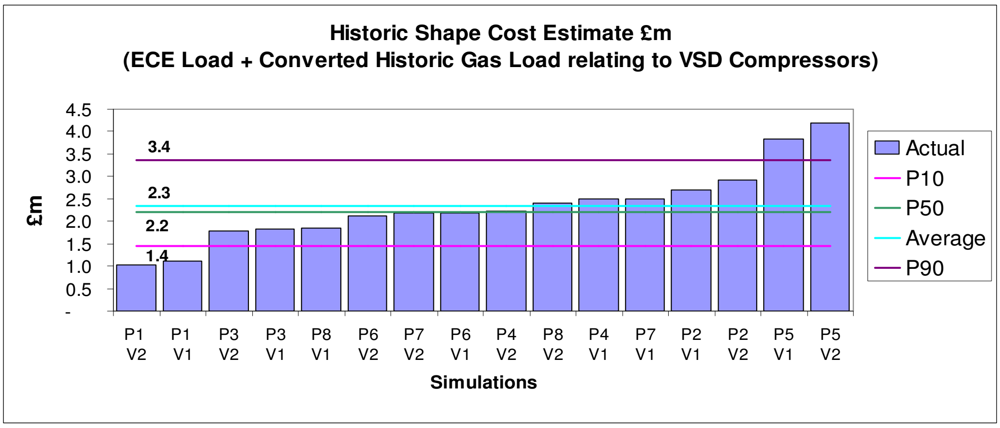
3.18 Looking forward, the commissioning of new electric compressors will see a significant step change in use of electricity compressors over the RIIO-T1 timeframe relative to current operational levels.



3.19 As with gas, we consider application of a cost allowance rather than unit price appropriate to mitigate the risk associated with energy forecasts. However, a benchmark of the electricity swing cost can only be based on ex-post market prices.

3.20 To form a view of what an appropriate electricity swing cost allowance, we have derived the electricity equivalent compressor consumption from historic gas compressor load over the two year period from 1 April 2010 to 31 March 2012.

3.21 This consolidated 2 year energy view of half hourly electricity consumption has then been applied to cash out prices over the last 8 years.



3.22 The analysis highlights an annual average electricity swing cost of £2.3m p.a with P10 – P90 values of £1.4m - £3.4m.

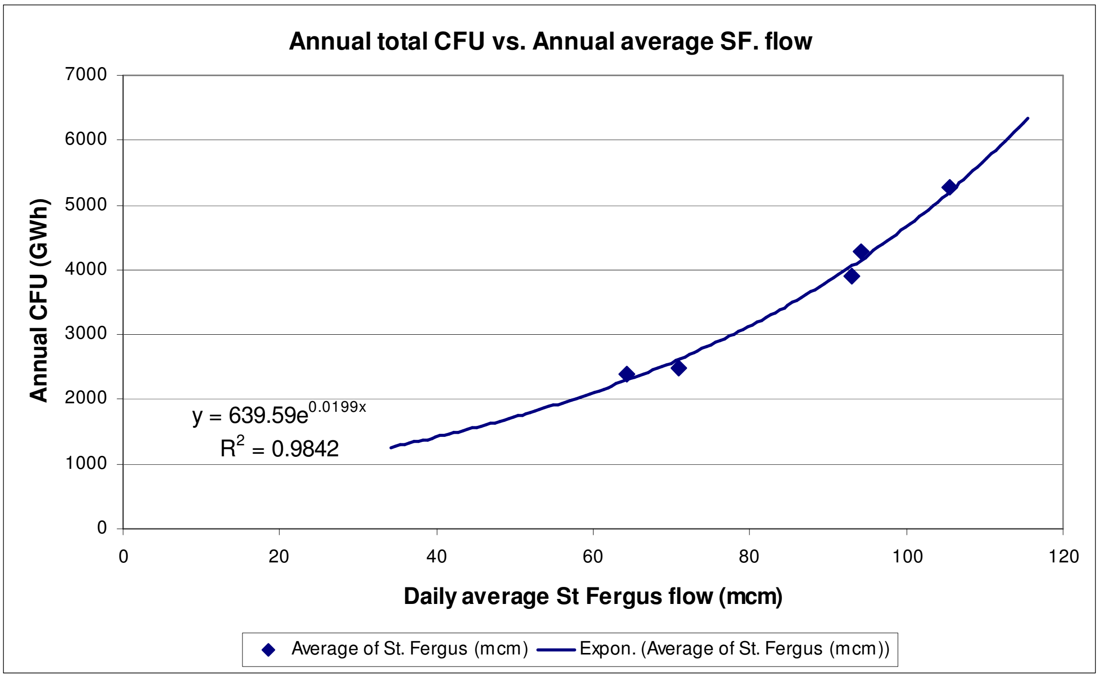
3.23 The analysis is based on limited historic data and assumes that electric compressors usage in the future will be consistent with historic gas compressor use. Uncertainties also remain over how future electricity cash out prices will evolve and the form electricity contracts will take going forward (the existing electricity contract expires in September 2013).

3.24 Recognising these uncertainties, we consider a £2.3m per annum electricity swing cost target appropriate with a review point after 2 years.

Appendix 4: Compressor Fuel Use (CFU) Target

4.1 The NTS shrinkage scheme includes an incentive to reduce the volume of CFU (including both gas and power energy requirements). This is done by calculating a deemed efficient use of CFU, against which outturn CFU is compared.

4.2 The deemed efficiency target is based on regression analysis to compare historical annual flows at St Fergus against historical annual CFU volumes. Historically, the St Fergus flow has shown the correlation to overall CFU volumes and is used as the basis for 2012/13 target.



4.3 Using a forecast of St Fergus flows gives an ex-ante CFU target. Actual St Fergus flows are then used to adjust the target to give an ex-post target, against which performance (actual CFU volumes) is measured. For 2012/13, a linear adjustment is used. This is a simplified approximation of an ex-post calculation of CFU and is an update (minimal change for rollover) to previous CFU volume mechanisms.

Proposed Approach

4.4 It remains appropriate to retain an incentive to reduce CFU volume, and we considered three options in order to deliver this:

(a) A qualitative volume incentive

(b) A separate quantitative volume efficiency measure; and

(c) The removal CFU volumes from the forward shrinkage reference volumes

A qualitative volume efficiency incentive

4.5 With no specific financial CFU volume efficiency incentive mechanism in place, we would be required to demonstrate efficient and economic compressor usage as part of the overall shrinkage incentive.

4.6 Demonstration that CFU volumes are efficient would take into account factors such as demand, supply/demand patterns, line pack, customer data provision, maintenance requirements and construction outages.

A separate efficiency measure

4.7 Under this option, an efficiency mechanism would be introduced to incentivise the efficient operation of compressors such that;

(a) The efficient volume of CFU is used to set a target;

(b) Outturn CFU volumes are compared against target in order to identify efficiency volumes; and

(c) A reference price is applied to the efficiency volume (target c.f. outturn) to derive an incentive cost.

4.8 This is in addition to the environmental element, which would be calculated in a similar way, but using the traded price of carbon as the price.

The exclusion of CFU from baseline reference target

4.9 Where CFU is excluded from the baseline energy procurement target, we envisage CFU would continue to be incentivised following similar principles to the existing methodology.

4.10 This is in addition to the traded price of carbon environmental element.

Setting CFU Targets

4.11 For some of the options, an ex-ante baseline reference volume needs to be forecast. For others, an ex-post target needs to be calculated. The table below summarises which options require CFU targets to be set either ex-ante or ex-post.

4.12 For comparison, the current scheme uses an ex-ante target with an ex-post adjustment. This is essentially the same as just having an ex-post target as per option 3.

Option		Ex-Ante Target	Ex-Post Target
1	Non-financial, report and justify	Baseline reference volume	Environmental performance
2	Separate efficiency measure	Baseline reference volume	Deemed efficiency target + Environmental performance
3	Exclude from baseline reference volume	*Not required*	Deemed efficiency target + Environmental performance

4.13 The different options for the reference baseline volume and the deemed efficient CFU volume need to be assessed against the following criteria:

(a) Accuracy over the required period (annual or quarterly)

(b) Robustness for eight years

(c) Ability to codify methodology into licence; and

(d) Simplicity for ease of understanding and transparency

4.14 The possible approaches to calculating baseline reference volume and calculating a deemed efficiency target are inherently different. An ex-ante baseline reference volume can only be based on forecasts of supply/demand patterns, as different supply/demand patterns require different volumes of CFU to operate the NTS.

4.15 Regression analysis remains an appropriate way to calculate the CFU baseline reference volume.

4.16 A range of regression analysis has been undertaken using data from the last six years to try to identify the most accurate and appropriate drivers of CFU, including;

(a) Aggregated System Entry Point (ASEP) flows, temperature, composite weather variable, national demands for regression drivers;

(b) Individual ASEPs and various combinations of ASEPS;

(c) The granularity of detail, i.e. daily, weekly etc; and

(d) The time period upon which the analysis is based.

4.17 Neural networks have also been used to analyse CFU. The underlying principles and assumptions however are not defined and are therefore less appropriate than traditional regression. The use of neural networks has not shown to give improved calculations of CFU.

4.18 The analysis showed that the best results can be obtained when the level of detail for inputs and required results are the same. So if an annual CFU volume if required, it is best to undertake regression using annual data. If CFU volumes are required for each quarter, it is best to use quarterly historical data to undertake the regression analysis etc.

4.19 When calculating annual or quarterly CFU, many years of historical data are required so the time period needs to be as long possible. Accurate records exist back to 2006/7, so this is the time period used.

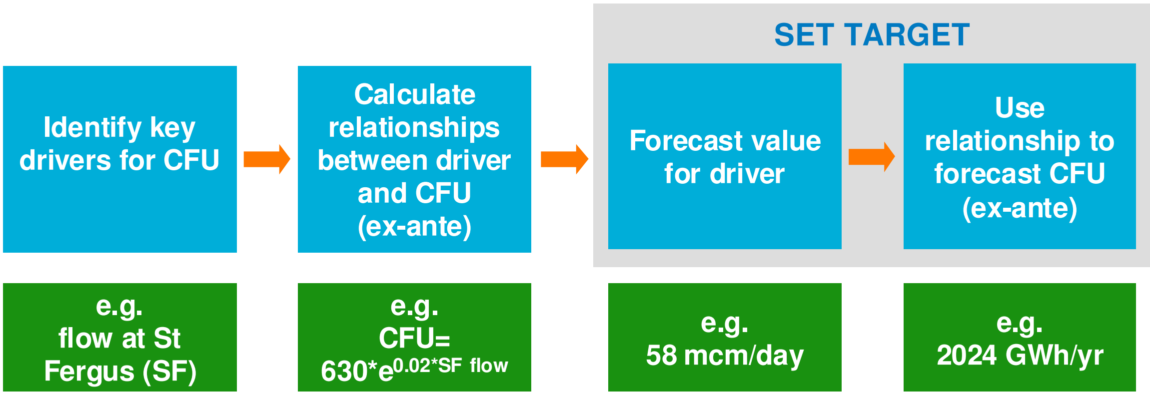
4.20 ASEP flows are shown to be the most accurate driver of CFU, rather than using combinations of ASEP flows and temperature or demands or composite weather variable.

4.21 We expected to find that using flows from many ASEPs would give more accurate CFU forecasts, but the flows from just one ASEP, St Fergus, remains not only the strongest driver but including other ASEPs in the regression analysis actually adds no more significant accuracy. This is true for both annual and quarterly forecasts.

4.22 In order to ensure that network and flow pattern changes are incorporated into the baseline reference volumes we propose to recalculate this relationship each year including the most recent year's outturn data. This will increase the robustness of the methodology.

4.23 The predicted changing usage of the NTS and resulting changes in supply patterns means that this methodology may not be robust for the full eight years of RIIO-T1 and we propose to review the methodology for calculating the baseline reference volume after four years.

4.24 The diagram below illustrates the proposed approach for setting the ex-ante baseline reference target.



Appendix 5: Residual Balancing Supplemental Information

Daily Linepack Performance Measure

5.1 It is proposed that the Daily Linepack Performance Measure (LPM) is determined as follows:

$$\mathbf{LPM} = |(\mathbf{CLP} - \mathbf{OLP})|$$

Where

CLP means the Closing Linepack volume (in mcm) on the relevant gas day

OLP means the Opening Linepack volume (in mcm) on the relevant gas day

Exceptional Event Adjuster

5.2 This mechanism would necessitate additional terms to define the performance target range (mcm). Accordingly the existing proposed definition of Linepack Performance Target would apply where the previous day's linepack change was less than 8mcm, however, where the change was 8mcm or greater, an different Linepack Performance Target Upper Limit (LPTUL) and Lower Limit (LPTLL) would apply. Accordingly:

If |(CLPD – OLPD)| is <8mcm then

LPTUL = CLPD + Linepack Performance Target

LPTLL = CLPD - Linepack Performance Target

Otherwise,

LPTUL = (Max (CLPD, OLPD)) + Linepack Performance Target

LPTLL = (Min (CLPD, OLPD)) – Linepack Performance Target

where

CLPD means the Closing Linepack volume (in mcm) on the previous gas day
OLPD means the Opening Linepack volume (in mcm) on the previous gas day

Appendix 6: Residual Balancing – Cost Minimisation

6.1 As described in the Residual Balancing Section of this Business Plan, Ofgem has indicated that it is considering the introduction of a Cost Minimisation Scheme for Residual Balancing. The following details our analysis in respect of such a scheme.

Assumptions

6.2 We have made an assumption that an incentive to minimise net costs is accompanied by an incentive to keep Closing Linepack (CLP) close to Opening (OLP), similar to the linepack component of the current scheme. In making our trading decisions on each gas day, we would then be taking into account the impact on the cost incentive and the linepack change incentive – in a similar way as we currently "trade off" the price performance measure and linepack performance measure.

Balancing a short market (less supply than demand)

6.3 In order to minimise net costs, National Grid could seek to trade in different ways depending on whether the market was short or long. Where on a gas day, the market is short, indicated by values of Predicted Closing Linepack (PCLP) some way below OLP, if we expect that the market will naturally resolve the imbalance to a sufficiently low level we are unlikely to trade. We would expect CLP to be close to OLP, with no costs incurred.

6.4 Otherwise, if we expect that this within day imbalance will persist, and the end of day imbalance will leave CLP some way from opening, we would look to buy, and achieve the desired increase in linepack from the minimum cost of trades. It is likely that we would await an opportunity to trade a small volume up to a relatively high price in order to set the 'System Marginal Price (SMP) Buy' cashout price above the default level (currently equal to the System Average Price (SAP) plus 0.77p/therm). This would encourage shippers who are 'short' to address their imbalance. We would thereby expect to achieve CLP close to OLP, at a relatively small cost.

6.5 There is an immediate consequence of this activity. Shippers who are short pay a sum equal to 'SMP Buy' price multiplied by their imbalance volume into Balancing Neutrality, the same "pot" as residual balancing revenues and costs are passed through. So, if the market becomes less short, the total in Balancing Neutrality decreases, and so therefore does the value of each shipper's share of it.

6.6 Another effect of this activity (setting 'SMP Buy') is a tendency to increase market prices. For a shipper who is short by, for example 1mcm, it is likely to be more economic to purchase 1mcm of gas at anything up to the 'SMP Buy' price as opposed to incurring the costs of cashout of the volume at SMP Buy. The increase in the 'SMP Buy' will tend to increase market prices on that day and potentially apply upward pressure on prices for subsequent days, therefore increasing overall costs.

6.7 Market conditions, and in particular price stacks on the OCM, are not within our control, so the opportunity to set 'SMP Buy' may not arise. In this case, it is likely that we would seek to buy a significant part of the imbalance, at price that does not set the 'SMP Buy' price. However, if doing so means that the downside on a cost incentive outweighs the upside on the linepack incentive; we could retain an imbalance and address the following day when market conditions could be more favourable.

6.8 Minimising the volume, and therefore the cost, of trading to balance the 5mcm short market, could have the unintended consequence of inflating prices on the OCM. This could raise gas prices the next day both on the OCM and the larger brokered markets. Hence this approach could add greater volatility to the within day market. This illustrates the distinction between minimising the net cost of residual balancing and minimising the energy balancing costs of the whole market.

6.9 The opportunity we have to trade in different ways depends on market conditions during the day. Within the balancing window (from the start to near the end of the gas day) the OCM is a live market, with changing and incomplete bid and offer stacks, and no gate closure, unlike the equivalent electricity Balancing Mechanism.

Balancing a long market

6.10 Now consider a gas day when the market is long, and we expect this to persist to the end of the day. To minimise net costs, it is likely we would seek to reduce linepack towards opening level by selling with the maximum trading revenue, as this represents a negative cost and is encouraged under a net cost scheme.

Setting a Performance Target for a net cost scheme

6.11 In order to implement a net cost minimisation scheme, two main elements need to input into the calculation of a net cost target: the price at which we could be expected to procure or sell energy, and the appropriate volume required to resolve the prevailing imbalance. Indexes for volume and price could reduce the effect of factors outside National Grid's control, in particular the future level of gas price, and the future market length, in order to focus the incentive on factors within National Grid's control.

6.12 Although the price of actions could be measured against market prices on the day, the volume of actions is problematic to index, because (as described above) it depends on the particular bid or offer stacks available during the day, which are incomplete and changing. Hence there is no clear way of setting a volume target for a year ahead, or even eight years, with any confidence, and adopting such an approach could potentially lead to windfall profits or losses. We give more detail on this below.

6.13 An index for price is simple and could be based on SAP +/- an increment, related to default cashout price. However an index for volume is much more challenging. Although shipper imbalance is the primary driver of balancing trades, the volume effect of Title trades is not 1:1 or uniform or predictable.

6.14 The volume of trades is driven by

(a) The natural market imbalance (and therefore the change in linepack) that would occur without any National Grid residual balancing actions.

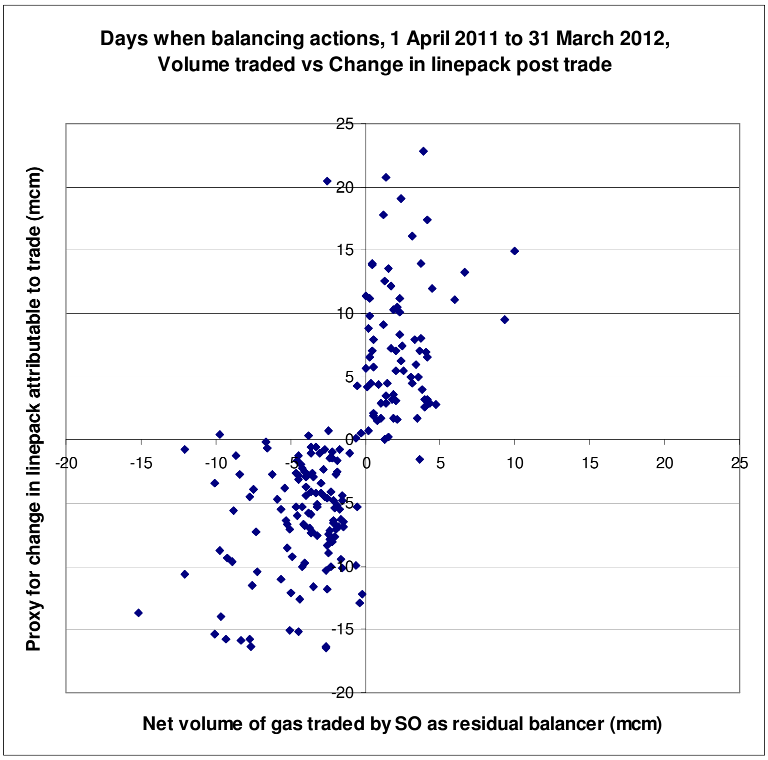
(b) The required degree of imbalance at the end of the gas day, to maintain a safe operational environment. A perfect match for supply and demand is difficult, unnecessary, inefficient, or uneconomic.

(c) The market reaction in volume to National Grid's trades. For example, if we buy a small volume, at a price that sets the SMP Buy price, then the market may respond by changing supply or demand with a relatively large volume effect.

6.15 On the days when we do trade, we do not know what market imbalance would have been had we not traded. Hence the yardstick for measuring our actual volume requirement is unknown. This is because the user can change their imbalance position freely throughout the gas day. On the days when we do not trade, we do not know how to gauge what volume would have been required to balance (if any).

6.16 One approach could be to use an average volume effect of our trades. In order to look at this, we have done some analysis of the last incentive year 2010/11. On each day that National Grid did residual balancing actions, we have taken the Predicted Closing Linepack (PCLP) at the hour just prior to the first action, and subtracted this from the Closing Linepack (CLP), to show the change in linepack seen from just before the action to the end of the gas day. We can then attempt to correlate this change with the volume traded. The following chart shows the scatterplot.

Volume traded versus change in linepack post trade



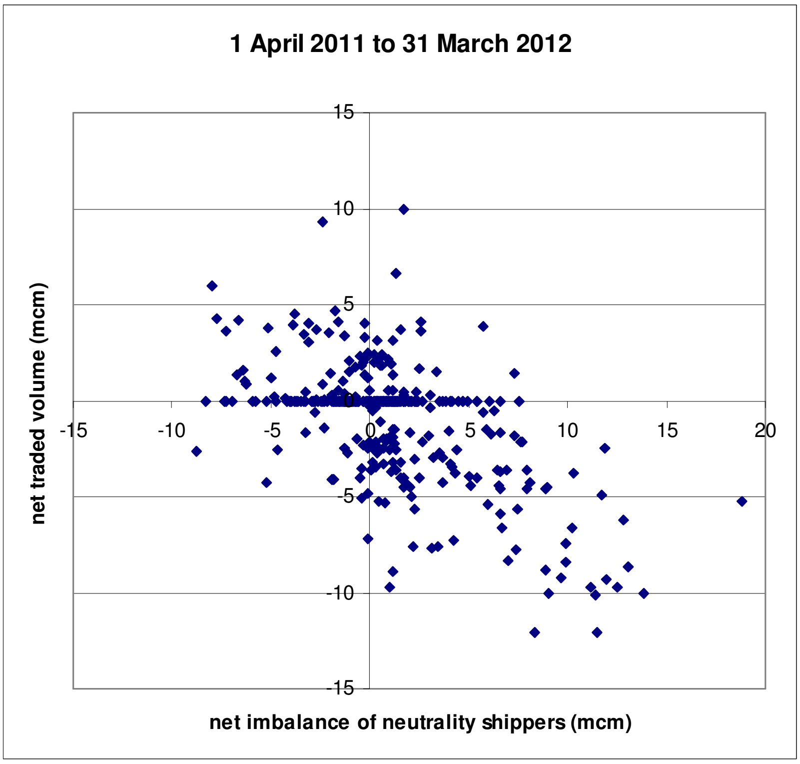
6.17 As the above chart shows, in incentive year 2010/11, when we have done residual balancing buys, we have tended to buy up to 5mcm, but for similar buy volumes the subsequent linepack change, while generally positive, has been anything up to around 20mcm. When we have done residual balancing sells, we have traded a higher volume, generally up to around 10mcm, and again on different days with similar volumes of sales, the subsequent linepack change has ranged between zero and around 15mcm.

6.18 Using an average volume effect of our trades will not adequately represent the large range of effects we see over different days with different trading conditions. The effect of our trades is not the same for all physical parties – cashout only affects shippers. Furthermore, using an unrepresentative index for volume would create inappropriate commercial incentives for a day to take into account alongside a linepack change incentive.

6.19 Traded volume is not well correlated with shipper imbalance, either at end of day, or within the day (18:00). This is demonstrated in the following graphs.

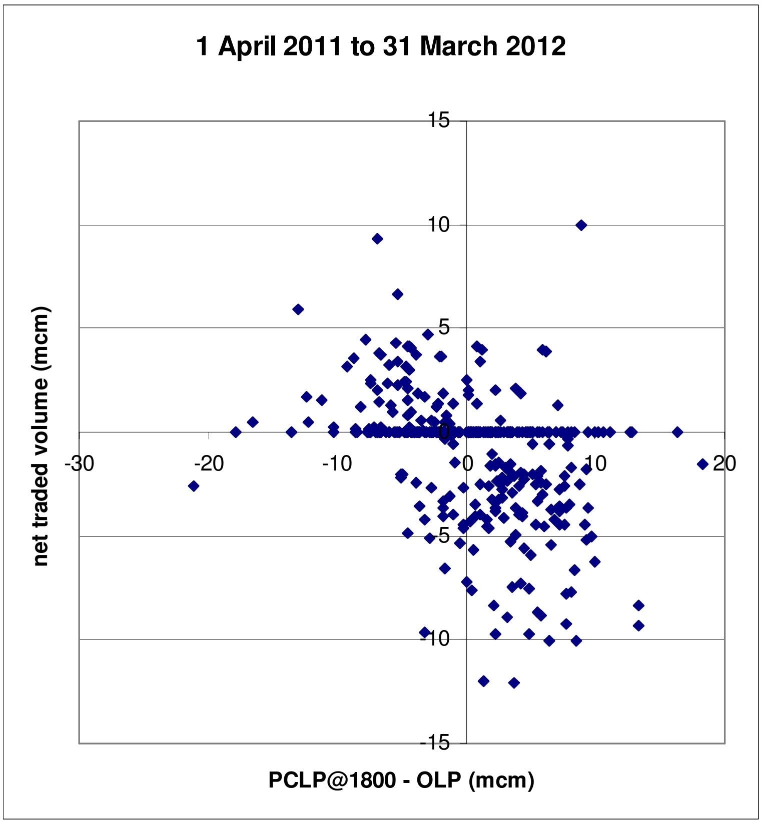
6.20 The following chart shows net traded volume against end of day shipper imbalance for each day in the last incentive year 2010/11. The graph shows the huge range of traded volumes for a particular level of shipper imbalance. (A 1:1 relationship would be a diagonal line from top left to bottom right with gradient -1.) This is not due to seasonal variation of linepack (higher in winter, lower in summer) or because of targeting closing linepack away from opening, but due to the different volumes necessary for different strategies in different market conditions. The charts also show the many days when National Grid chose not to take actions.

Shipper imbalance versus traded volume, 2011/12



6.21 An alternative candidate for a volume index is the imbalance of the market halfway through the gas day, at 1800, after the close of the brokered markets. This is given by PCLP at 1800 – OLP. Residual balancing actions are typically done after this time, giving the market time to self balance without intervention. The following chart shows the relationship for the last incentive year 2011/12.

1800hrs imbalance versus traded volume, 2011/12



6.22 As before, we see a large range of volume for similar levels of market imbalance, including the many “no trade” days, and this is again explained by the different conditions from day to day. To pursue a volume index any further, we would have to consider OCM bids and offers submitted during each gas day, and attempt to unpick market reaction - a challenging exercise.

Appendix 7: Demand Forecasting Supplemental Information

Determination of Seasonal Target from Base Year

7.1 It is proposed that the seasonal targets for the base year be derived as follows:

$$\text{Summer Target} = \text{Min}\left(\text{ADFE April 2011 to September 2011},\ \text{ADFE April 2012 to September 2012}\right) + \text{Volatility Adjustment}$$

$$\text{Winter Target} = \text{Min}\left(\text{ADFE October 2011 to March 2012},\ \text{ADFE October 2012 to March 2013}\right) + \text{Volatility Adjustment}$$

where

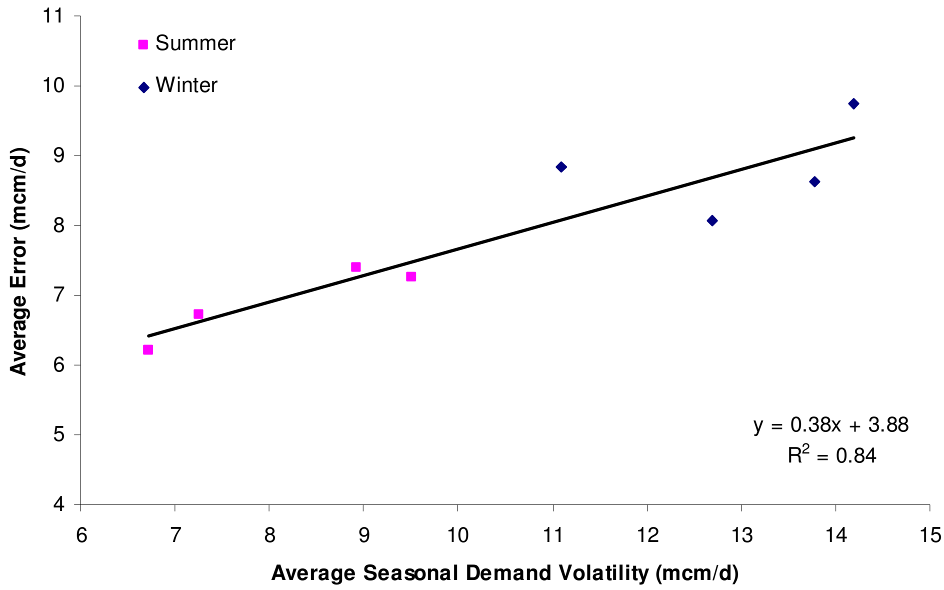
ADFE is the Mean Absolute Daily forecast error (mcm) within the relevant period

7.2 The proposed Volatlity Adjustment is described further below.

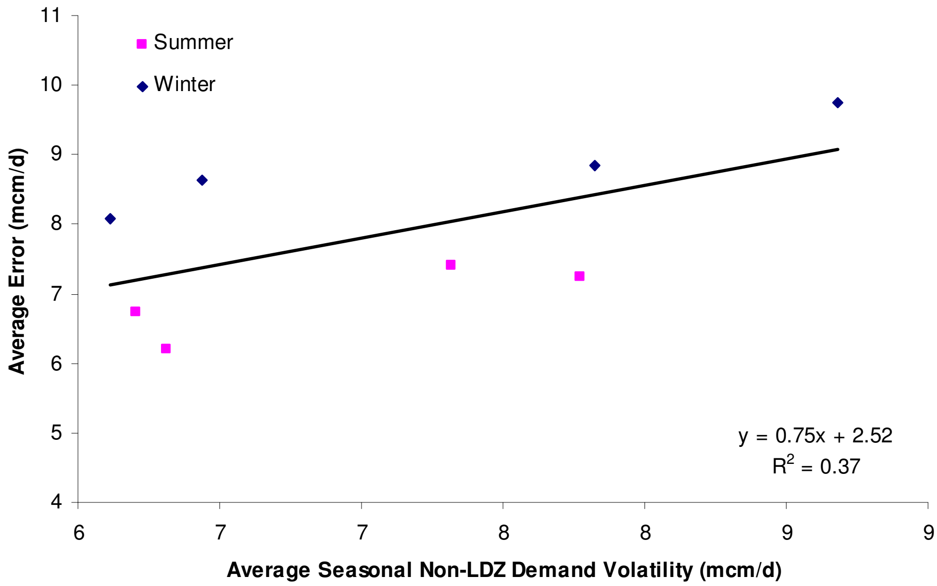
Demand Volatility Analysis and Adjuster

7.3 The chart below illustrates regression analysis of the relationship between the average day to day volatility of demand and the average absolute forecast error, by season, over the last four years. There is clearly a strong relationship (R^2 value of 0.84) between demand volatility and the accuracy of the demand forecast. National Grid is currently on average able to forecast 62% of the volatility.

7.4 We are therefore proposing that the adjustment factor should be 38% of any change in volatility from that seen in the base year.



7.5 In our stakeholder workshop one industry party raised a question regarding the exclusion of DN demand from any volatility adjustment to isolate what it viewed as the primary drivers of demand volatility. Our analysis has concluded that exclusion of such would dilute the correlation (R2 value down to 0.37) between demand volatility and forecast error as indicated by the following chart



7.6 On the basis of the above analysis, it is proposed that the volatility adjustment is determined as follows. The base year will be the year in which forecast performance was lower between Incentive Years 2011/12 and 2012/13.

$$\text{Volatility Adjustment} = 0.38 \times \left(\text{Demand volatility in current year} - \text{Demand volatility in base year} \right)$$

7.7 We propose that Demand Volatility in any year will be determined as follows:

$$Volatility = \frac{\sum_d \left| (\textbf{Demand on gas day} - \textbf{Demand on previous gas day}) \right|}{\textbf{Number of days in year}}$$

Where $\sum_d$ means the sum across all gas days in the relevant incentive year

Weighting of Target and Performance

7.8 In order to derive a single daily target and single daily performance metric, the values relevant to the respective timed forecasts will be aggregated in accordance with the following formulas:

Overall Target = (D5T*0.1) + (D4T*0.1) + (D3T*0.1) + (D2T*0.2) + (D1T*0.5)

where

D5T	is the relevant seasonal D-5 NTS demand forecasting target
D4T	is the relevant seasonal D-4 NTS demand forecasting target
D3T	is the relevant seasonal D-3 NTS demand forecasting target
D2T	is the relevant seasonal D-2 NTS demand forecasting target
D1T	is the relevant seasonal D-1 13:00 demand forecasting target

Overall mcm Error = (E5A*0.1) + (E4A*0.1) + (E3A*0.1) + (E2A*0.2) + (E1A*0.5)

where

E5A	is the D-5 seasonal daily average absolute demand forecast error
E4A	is the D-4 seasonal daily average absolute demand forecast error
E3A	is the D-3 seasonal daily average absolute demand forecast error
E2A	is the D-2 seasonal daily average absolute demand forecast error
E1A	is the D-1 13:00 seasonal daily average absolute demand forecast error

7.9 The seasonal demand forecast error values shall be determined on the basis of the following:

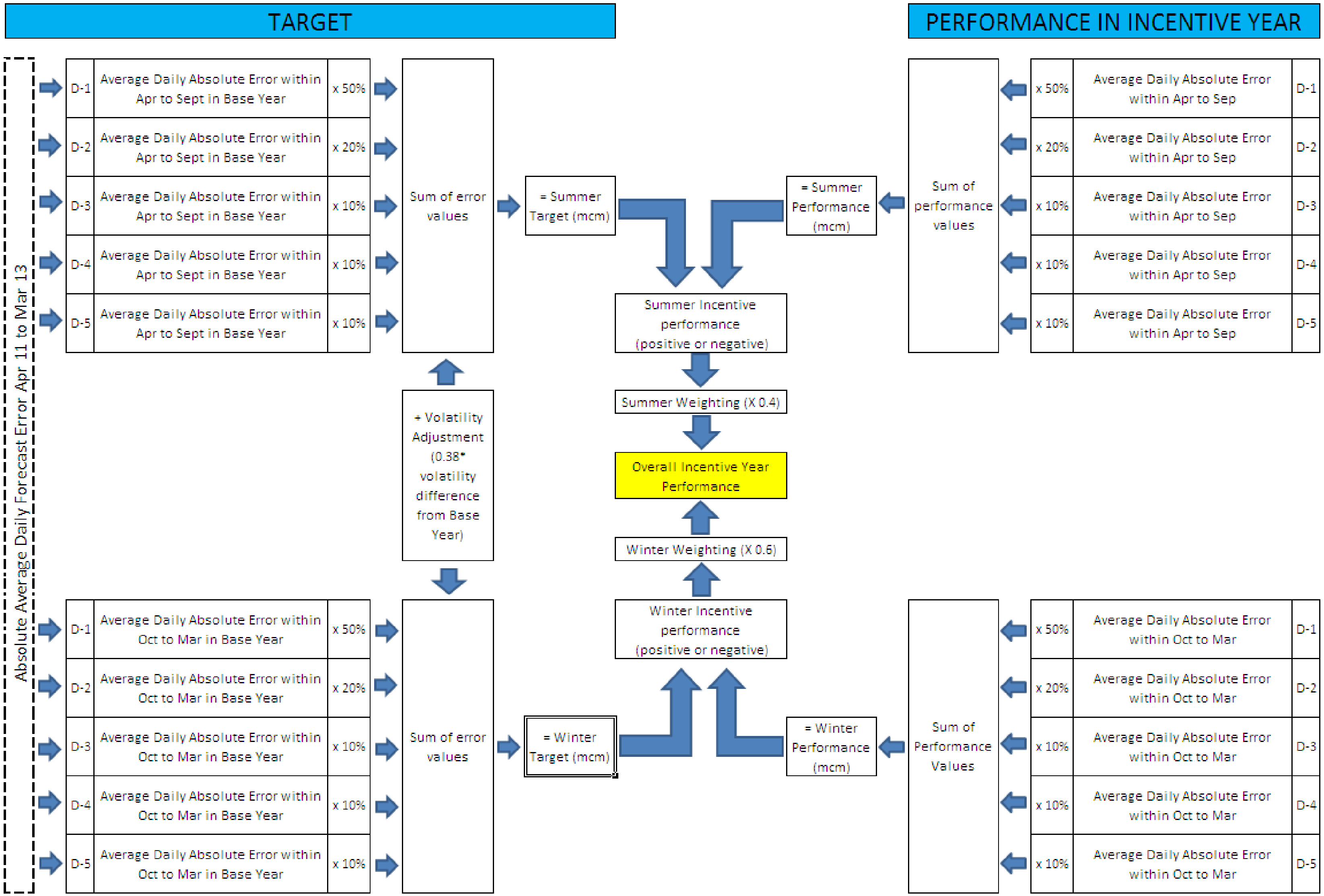
$$\text{Seasonal Daily Average Absolute Demand Forecast Error} = \frac{\text{Sum of Daily Values within season} \left| (\text{Forecast Demand} - \text{Actual Demand}) \right|}{\text{Number of Days within Season}}$$

Overall Incentive Year Performance

7.10 It is proposed that a weighted average (3:2 for Winter: Summer) will subsequently be used determine overall annual performance. This would be applied as follows:

$$\text{Annual Performance} = \left(\left(\text{Overall Summer Error} - \text{Overall Summer Target} \right) * 0.4 \right) + \left(\left(\text{Overall Winter Error} - \text{Overall Winter Target} \right) * 0.6 \right)$$

7.11 The diagram on the following page provides an overview of the derivation of the targets and the performance measures for the NTS Demand Forecasting Incentive.


TARGET
PERFORMANCE IN INCENTIVE YEAR
Absolute Average Daily Forecast Error Apr 11 to Mar 13
D-1 Average Daily Absolute Error within Apr to Sept in Base Year x 50%
D-2 Average Daily Absolute Error within Apr to Sept in Base Year x 20%
D-3 Average Daily Absolute Error within Apr to Sept in Base Year x 10%
D-4 Average Daily Absolute Error within Apr to Sept in Base Year x 10%
D-5 Average Daily Absolute Error within Apr to Sept in Base Year x 10%
Sum of error values
= Summer Target (mcm)
+ Volatility Adjustment (0.38* volatility difference from Base Year)
D-1 Average Daily Absolute Error within Oct to Mar in Base Year x 50%
D-2 Average Daily Absolute Error within Oct to Mar in Base Year x 20%
D-3 Average Daily Absolute Error within Oct to Mar in Base Year x 10%
D-4 Average Daily Absolute Error within Oct to Mar in Base Year x 10%
D-5 Average Daily Absolute Error within Oct to Mar in Base Year x 10%
Sum of error values
= Winter Target (mcm)
Summer Incentive performance (positive or negative)
Summer Weighting (X 0.4)
Overall Incentive Year Performance
Winter Weighting (X 0.6)
Winter Incentive performance (positive or negative)
= Summer Performance (mcm)
Sum of performance values
x 50% Average Daily Absolute Error within Apr to Sep D-1
x 20% Average Daily Absolute Error within Apr to Sep D-2
x 10% Average Daily Absolute Error within Apr to Sep D-3
x 10% Average Daily Absolute Error within Apr to Sep D-4
x 10% Average Daily Absolute Error within Apr to Sep D-5
= Winter Performance (mcm)
Sum of Performance Values
x 50% Average Daily Absolute Error within Oct to Mar D-1
x 20% Average Daily Absolute Error within Oct to Mar D-2
x 10% Average Daily Absolute Error within Oct to Mar D-3
x 10% Average Daily Absolute Error within Oct to Mar D-4
x 10% Average Daily Absolute Error within Oct to Mar D-5

Appendix 8: Stakeholder Engagement

NTS shrinkage

What stakeholders said	What is in our May 2012 plan
Stakeholders continue to support a cost minimisation incentive for Shrinkage and have recognised our good performance in recent years in our management of energy procurement which has resulted in savings for consumers	*We have proposed retention of a cost minimisation incentive with an overall cost target based upon target volumes and benchmark energy prices.*
There are concerns that Unaccounted for Gas (UAG) has come to dominate the shrinkage allowance in volumetric terms, in part due to recent meter errors	*Recognising these concerns, we undertook a new Licence Condition in April 2012 (see below).*
It seems perverse that the industry faces increasingly higher UAG costs yet National Grid continues to maximise its returns from the shrinkage incentive	*Consistent with the SO Incentive Principles our shrinkage proposals seek to sharpen the incentive to focus on elements which are within the SO's control.*
National Grid should publish a breakdown of the shrinkage data so the industry can clearly see the impact of UAG	*We are currently considering the most appropriate method of providing this information to the industry.*

Unaccounted for gas (UAG)

What stakeholders said	What is in our May 2012 plan
Stakeholders are concerned about the growth in UAG, highlighting it has been recently driven by a number of meter errors.	*We have proposed continuation of our obligations under the new UAG licence condition[82] introduced in April 2012. This requires us to undertake investigations into the causes of UAG and periodically report our findings to Ofgem. We proactively work with the industry by witnessing meter validation activities and contribute to the resolution of meter errors in a timely manner in accordance with obligations under the UNC.*
Whilst stakeholders acknowledge the errors may not be on our meters, a number have said National Grid is in a unique position and should be able to provide information to the industry outlining details	*We recognise our central role in the market and therefore advocate continuation of the existing reputational incentive. This includes obligations to publish on our website reports on the witnessing of Measurement Equipment*

[82] Special Condition C29 of the NTS GT Licence

of meter inspections and meter performance, including information regarding errors. A meter accuracy incentive may be appropriate to avoid future errors	*validation and data centred investigations. Information in respect of meter errors is available on the Joint Office of Gas Transporters website[83]*
A number favoured a financial incentive for UAG rather than a reputational one	*Consistent with the principle that the SO should only exposed to risk we can meaningfully manage, influence or mitigate against rather than those that we are unable to control or reasonably forecast, we have concluded that a financial incentive is not appropriate in this area.*

Demand forecasting

What stakeholders said	What is in our May 2012 plan
The majority of stakeholders reiterated that the accuracy of the day-ahead (D-1) 13:00 hrs demand forecast is important to them. There was limited interest in the earlier demand forecasts becoming incentivised.	*We have proposed to incentivise a range of forecasts in the NTS Forecasting incentive scheme including the D-1 13:00 demand forecast. The focus of this incentive remains the D-1 forecast with a 50% weighting attributed to the forecast alone. The remaining 50% is apportioned amongst the four forecasts produced over the previous four days*
Seasonal targets should be considered in the demand forecasting	*We have proposed that seasonal targets are utilised for NTS demand forecasting (a winter target for October to March and a summer target for April to September).* *Further, we have proposed to weight the overall NTS Demand Forecasting incentive value such that performance against the winter target determines 60% of the incentive value.*
The accuracy of Non Daily Metered (NDM) demand forecast was highlighted as an important area where improvements could be sought.	*We have proposed the introduction of new NDM forecasting and associated incentive which is measured by its accuracy relative to the existing version produced in accordance with the terms of the UNC.*

[83] http://www.gasgovernance.co.uk/MER

Information Provision

What stakeholders said	What is in our May 2012 plan
A number of stakeholders have said our data provision has improved over recent years.	*We have proposed to engage with our stakeholders and customers later in 2012 to inform our prospective data provision strategy to ensure that it addresses their future needs.*
The data provided is important and flows directly into the industry's processes therefore a reputational incentive is appropriate if supported by agreed publish metrics	*We have proposed replacing this financial incentive with a reputational one which includes the publication of performance standards.*
European and other regulatory developments may require the provision of additional information in the future	*We recognise that there are considerable uncertainties in many areas (including in respect of information provision) within the RIIO-T1 period. This is one of the drivers for our proposed approach in this area.*

Residual balancing

What stakeholders said	What is in our May 2012 plan
The majority supported retaining the incentive with its current arrangements as it has worked well, although a number felt the incentive should be tightened to further improve National Grid's performance	*We have proposed retention of the PPM and LPM measures. We have proposed dynamic performance targets which seek to provide fair and equitable performance benchmarks which are reflective of market conditions.*
Many stakeholders have been supportive of the ongoing review of the Price Performance Measure (PPM) whilst there are mixed views as to whether the Linepack Performance Measure (LPM) is needed.	*We have proposed retention of the PPM and LPM measures, the latter to support the 'polluter pays' principle and our obligations to maintain cost reflectivity.*
There was little support for a cost minimisation incentive because the current incentive was working well	*We are concerned that a cost minimisation incentive will have undesirable impacts on the market and have therefore not included it in our proposals. The combined effect of the LPM and PPM schemes will incentivise us to minimise Residual balancing costs whilst minimising our impact on the market.*
Stakeholders questioned why we were proposing to double the daily maximum value when it seemed we were not proposing to provide anything new or of additional value to them	*In our business plan we explain our view that the current Residual Balancing scheme undervalues the service provided by the SO in terms of the value of the gas traded and the impact of actions.* *We assert that the current scheme value is arbitrary and has evolved from the parameters of preceding schemes.*

	Alternatively we propose linking value to the prevailing cashout differential price.

Environmental

What stakeholders said	What is in our May 2012 plan
For greenhouse gas emissions (venting) a number of stakeholders have pointed to our public objective to reduce greenhouse gases and questioned whether an incentive is required, with a number saying a reputational incentive would suffice.	*The RIIO-T1 capital plans for our UK businesses include capital investment to reduce or eliminate both vented and combustion emissions wherever this is economic and efficient, or mandated by legislation. We propose to retain the existing emissions framework that incentivises us to reduce the inherent level of emissions even further wherever operational decisions permit.*
Stakeholders suggested a move to a five year rolling average target for venting could be an appropriate target as more data becomes available.	*We have proposed a framework for setting targets using an industry consulted methodology. This maintains a sharp incentive by readily adapting the target to reflect our growing understanding of the scale, environmental impacts and economic / social costs of greenhouse gas emissions.*

Connections

What stakeholders said	What is in our May 2012 plan
Stakeholders wish to see an improvement in our connections service with a transparent and timely connections offer process in place.	*UNC Modification Proposal 0373 has identified the timeframe by which we will provide timely connections offers. We intend to work to this timeframe even if the Proposal is not implemented.*
There was limited support for an incentive to find new and innovative ways of delivering connections offers quicker than the UNC timescales being proposed under Modification 373	
Many stakeholders wish to see greater alignment between the gas connections and gas capacity processes.	*We have proposed two incentives in this area:* *A licence obligation to publish information on the time taken prior to an application for a Development Consent Order under the Planning Act (2008); and* *A financial incentive to encourage early delivery and penalise late delivery of capacity.*
General support for a reputational incentive to optimise the activities from signature of a bi-lateral contract to capacity application readiness	
Little support for a financial incentive to provide flexibility to adjust obligated lead times where there is a user requirement as could go against the principles of Modification 376.	*We have not proposed a financial incentive in this area.*

Constraint management

What stakeholders said	What is in our May 2012 plan
Stakeholders were supportive of the principle of the SO incentive targets changing to reflect the application of the TO uncertainty mechanisms	*We have continued with this approach of reflecting the impact of triggered TO uncertainty mechanisms in our SO constraint management incentive target.*
Stakeholders have reservations over combining exit and entry capacity management into one single incentives, with a number saying they do not support this proposal	*The plan explains why we continue to believe that the scheme should be designed to cover both entry and exit.*
In relation to the price we have used in our modelling assumptions, stakeholder views centred on the difficulty of setting a price for an 8 year control period	*We have continued to apply the same pricing assumption principles as used in the March TO submission, updating them to provide more detail on the assumptions we have made in relation to exit.*

Capacity scaleback

What stakeholders said	What is in our May 2012 plan
No stakeholder support for this incentive with a number saying a Modification to the UNC should be raised instead.	*A lack of stakeholder support for an incentive in this area may reflect the relative infrequency of scalebacks in the current environment. Accordingly we have concluded that a financial incentive would be appropriate.*

Maintenance and outage planning

What stakeholders said	What is in our May 2012 plan
Whilst stakeholders value the flexibility in the NTS maintenance schedule, some said they would welcome a financial incentive that penalises a party when maintenance days are changed without mutual consent.	*We propose introduction of an incentive scheme in respect of changes to the maintenance plan. Performance under this scheme is determined by the number of changes initiated by us, and by the customer.*
Stakeholders would like to see National Grid carry out its maintenance work 24 hours a day, seven days a week to meet the agreed timetables rather than changing the maintenance times.	*We plan to raise awareness of an existing service, the Minor Works Agreement, which is a bi-lateral arrangement whereby the customer is able to pay the incremental costs to us for working flexibly outside normal working practices.*

Customer satisfaction scheme

What stakeholders said	What is in our May 2012 plan
Stakeholders were wary that customer satisfaction would be measured by surveys alone. The survey itself must not be a resource burden on stakeholders.	*We continue to work with Ofgem and the other stakeholders on the format of the survey.*

Innovation

What stakeholders said	What is in our May 2012 plan
Innovation is important in meeting future challenges in an efficient and affordable manner. It should not be restricted to the TOs.	*We have concluded that it is appropriate to extend the Network Innovation Allowance (NIA) to the System Operator.*
The benefits of any innovation funding would need to be demonstrated to stakeholders.	*During the identification and prioritisation of research areas we will listen to stakeholders and focus our efforts on delivering innovative solutions to address their needs.*